NRC-005L

North Anna 3 Combined License Application

Part 3: Applicants' Environmental Report - Combined License Stage

Revision 8

June 2016

REVISION SUMMARY

Revision 8

Section	Changes	Reason for Change
2.7.6, 5.4.2.2; Tables 2.7-2, 2.7-4 thru 2.7-12, 3.0-1, 3.0-2, 5.4-4 thru 5.4-8, & 10.4-2	RAI 02.03.05-05, Modeling of Radwaste Building Vent Stack Releases	

Revision 7

Section	Changes	Reason for Change
1.3.3	Revised list of new and significant information	Unit 3 technology change from US-APWR to ESBWR
	Added bullet indicating information added to ER Sections 2.6.2.2.1 and 2.4.4.2.1	Indicate information contained in ER Sections 2.6.2.2.1 and 2.6.4.2.1
	Added bullet indicating information added to ER Section 4.5	Response to US-APWR S-COLA RAIs 12.03-46 and 12.03-47
Section 2.2 Reference, Section 2.4 References, Section 4.1 Reference, Section 4.2 Reference, Section 9.4 References	Update reference for PJM study	Updated study completed
2.7	Updated atmospheric dispersion information	Unit 3 technology change from US-APWR to ESBWR; ESBWR DCD changes from R5 to R9
Tables 3.0-1 & 3.0-2	Updated Unit 3 Site Characteristic Values vs. ESP Values	Unit 3 technology change from US-APWR to ESBWR; ESBWR DCD changes from R5 to R9
Tables 3.0-3 thru 3.0-8	Revised accident activity release information	DCD R9
3.2	Revised reactor power conversion system information	Unit 3 technology change from US-APWR to ESBWR
3.3.2	Revised water treatment information	Unit 3 technology change from US-APWR to ESBWR; changed water treatment plan
Table 3.3-1	Revised Unit 3 chemical injection points	Unit 3 technology change from US-APWR to ESBWR

Revision 7 *(continued)*

Section	Changes	Reason for Change
3.6.1	Revised plant effluent discharge information	Blowdown sump removed from design
3.7.1	Revised citation to PJM system impact study	PJM study updated
Section 3.7 References	Updated Reference 1	PJM study updated
Section 4.3 References	Added references 9 thru 11	Additional plant surveys performed
4.3.1.1	Updated plant survey information	Additional plant surveys performed
4.5	Updated construction worker radiation exposure evaluation information	Updated evaluation performed to address US-APWR S-COLA RAIs 12.03-46 and 12.03-47
5.3	Reflected results of updated SACTI analysis	Unit 3 technology change from US-APWR to ESBWR
5.4	Updated normal operation radiological impacts information	Unit 3 technology change from US-APWR to ESBWR; ESBWR DCD changes from R5 to R9
5.8, Figure 5.8-2	Deleted reference to UHS cooling tower and revised visual impact survey figure	Unit 3 technology change from US-APWR to ESBWR
7.1.4	Deleted reference to "two" accidents	Editorial
Tables 7.1-2 thru 7.1-5, 7.1-7, 7.1-9, & 7.1-10	Revised design basis accident doses information	DCD R9
7.3	Changed "GE" to "GEH"	Editorial
7.3.1	Deleted (ESP-ER reference)	Updated analytical inputs
7.3.2	Clarified source of SAMDAs	NEDO-33306 Rev 4 clarified the source of SAMDAs
	Inserted NEDO-33306 averted risk benefit value	Updated GEH analysis
	Updated GEH conclusions	Updated GEH analysis
7.3.3	Updated Unit 3 SAMA analysis	Updated to reflect the current ESBWR PRA and SAMDA analysis, and current site information

Revision 7 *(continued)*

Section	Changes	Reason for Change
Section 7.3 References	Changed Reference 1 from Revision 1 to 4 and August 2007 to October 2010	NEDO-33306 is Revision 4, ML1029904331
	Added Reference 2	NEDO-33201 Revision 6, ML 102880548
10.4.2	Updated O&M and decommissioning costs; revised land use information	Unit 3 technology change from US-APWR to ESBWR
Tables 10.4-1 & 10.4-2	Revised peak number of construction workers, land use, hydrological and water use, doses, and expected traffic impacts	Consistency with updates in other chapters

Revision 6

Section	Changes	Reason for Change
Various	US-APWR narrative to ESBWR information	Unit 3 technology change from US-APWR to ESBWR
1.1	Revised Unit 3 megawatt thermal (MWt) value	Electrical output of an ESBWR plant is different than that of a US-APWR plant
1.1.6	Revised potential construction start and fuel load dates	Milestones dates no longer valid
Figure 1.1-1	Revised site utilization plan figure	Revised to reflect ESBWR design and North Anna specific information
Figure 1.1-2	Revised site plan with building legend	Revised to reflect ESBWR design and North Anna specific information
Table 1.2-1	Revised federal, state, and local authorizations	Revised to reflect updated agency consultation status
1.3.3	Added bullet indicating information added to ER Sections 2.6.2.2.1 and 2.6.4.2.1	Indicate information contained in ER Sections 2.6.2.2.1 and 2.6.4.2.1
1A	Revised Environmental Protection Plan (EPP)	Revised to reflect level of detail in Revision 2 of NA3 ESBWR COLA ER
2.4.1.6, 4.3.1.2, 4A.2, 4B.2.4	Revised endangered species surveys description	Revised to reflect 2012 survey results
2.4.1.7	Revised rare plant species surveys description	Revised to reflect 2012 survey results

Revision 6 *(continued)*

Section	Changes	Reason for Change
Section 2.4 References	Added information regarding additional surveys	Updated with recent survey documents
2.6	Added narrative to describe information associated with seismological conditions and impacts	Provide information stemming from the new CEUS SSC model and the August 2011 Mineral, VA earthquake.
3.1	Deleted narrative associated with US-APWR UHS cooling towers	Consistency with ESBWR design
3.6	Deleted content regarding the blowdown sump	Design has changed and feature is no longer planned
Section 3.6 References	Updated date of regulation in Reference 3	Effective date changed
4.1	Deleted statement that land-use and other impacts associated with transport of large components to NAPS site is small	Pending updated Large Component Transport Route evaluation, removed impact statement
4.2.1.2, 4A.6	Added information regarding groundwater wells for construction and operations	Revised to provide additional detail on planned groundwater withdrawal during construction
Section 4.3 References, 4A.8	Added information regarding additional survey	Update with recent survey document
4A.1, 4A.5, Figure 4A-1	Deleted figures and references to figure	Additional property site utilization plan is included in Figure 1.1-1
4A.1, 4A.5	Deleted narrative associated with batch plant on additional property	Batch plant now planned to be inside EAB
Section 4B.4 References	Added information regarding additional survey Changed "Reference" to "References"	Update with recent survey document Editorial
5.9	Revised to provide ESBWR-specific narrative on decommissioning	Reflect ESBWR information
8.0	Updated information regarding net electrical generation's benefits, fuel diversity/mitigated and enhanced reliability, and emissions avoidance	Updated information
8.0.1.1	Revised values	Updated information
Section 8.0 References	Updated references	Updated information
Table 8.0-1	Revised	Updated information

Revision 6 *(continued)*

Section	Changes	Reason for Change
Table 8.0-2	Deleted	Deleted
Figures 8.0-1 thru 8.0-4	Revised	Updated information
8.1, 8.1.1	Editorial changes	Clarified content
Section 8.1 References	Updated references	Updated information
8.1.3	Updated service territory information and added information about the Regulation Act	Updated information
8.1.4	Updated PJM, Virginia, SCC, and NCUC information	Updated information
Tables 8.1-1 & 8.1-3	Updated information	Updated information
Figures 8.1-1 & 8.1-4	Updated information	Updated information
Figure 8.1-6	New figure	Updated information
8.2	Updated PJM and DSM information	Revised to incorporate PJM's 2012 report
Section 8.2 References	Updated references	Updated information
Table 8.2-1	Updated information	Updated information
Figure 8.2-1	Updated information	Updated information
8.3	Updated generating capability and purchase and sales information	Updated information
Section 8.3 References	Updated references	Updated information
Table 8.3-2	Deleted	
Tables 8.3-3 thru 8.3-9	Updated information	Updated information
Figures 8.3-1 thru 8.3-5	Updated information	Updated information
8.4	Updated information to support need for power evaluation	Updated information
Section 8.4 References	Updated references	Updated information
Tables 8.4-1 & 8.4-2	Updated information	Updated information
Chapter 9, Introduction	Deleted information about Virginia City facility	Deleted information
9.1	Updated information about capacity additions	Updated information
9.2.1	Updated information	Updated information

Revision 6 *(continued)*

Section	Changes	Reason for Change
Section 9.2 References	Updated references	Updated information
9.4	Updated information	Updated information

Revision 5

Section	Changes	Reason for Change
Chapter 1, 1.1, 1.1.1, 8.0.1.1, 8.1, 8.1.1, 8.1.2, 8.1.4.5; Figure 8.1-2	ODEC terminated its ownership interest in North Anna Unit 3.	Revised to reflect the change in ODEC ownership interest in North Anna Unit 3.

Revision 4

Section	Changes	Reason for Change
Figures 1.1-1 & 1.1-2	Changed electrical building size and SGBD facility relocated.	Reflect new Site Utilization Plan changes
Table 1.2-1	Updated the status and expiration dates for existing authorizations; added/deleted authorizations.	Update federal, state, and local authorizations
	Permit number and status updates.	New permits issued and received
1A	Entirely replaced.	Adopt latest NEI template
Table 2.3-1	Changed to be consistent with current VPDES Permit.	VPDES Permit
2.4.1.6	Updated the status of survey results communications to regulatory agencies.	New information regarding endangered species surveys
2.4.1.7	Updated plant-specific identification follow-up survey for Epling's hedgenettle.	New information regarding rare plant species surveys
Section 2.4 References	Added references 7 thru 10.	New references identified
2.5.3.5	Added the results of the survey conducted in 2011 of the LCTR.	New information regarding historical/cultural resources surveys
Section 2.5 References	Added reference 5.	New reference identified
2.7.6; Tables 2.7-1, 2.7-2 & 2.7-3	RAI MET-1, Meteorology/Air Quality; Revised distances to the EAB	
3.6.1	Deleted brackets around "essential."	Editorial
3.6.1, 3.6.2; Table 3.3-1	Changed "cooling tower blowdown sump" to "blowdown sump."	Editorial

Revision 4 *(continued)*

Section	Changes	Reason for Change
Table 3.0-1	Changed gaseous effluent dispersion site characteristic values and evaluation.	Consistency with response to RAI 11.03-4
	Changed EAB atmospheric dispersion factor evaluation.	Consistency with response to RAI MET-1
4.6	Editorial.	Editorial
4.7	Deleted.	Editorial
Table in 4A.2	Changed total acres from "95.6" to "95.5."	Editorial
4A.5	Deleted "areas."	Editorial
4B.1	Changed "lines" to "supplies" and "storm water" to "stormwater."	Editorial
4B.2.2	Changed "storm water" to "stormwater."	Editorial
Figure 4B-1	Added planned wells and Gen. Rewind Bldg.	New Site Separation Activities drawing changes
Tables 5.4-3, 5.4-4, 5.4-6 thru 5.4-8	See RAI 11.02-7, Cooling Tower Makeup Water Tritium	
9.3	Clarified SECY reference.	Editorial
Table 10.4-2	Changed "12.5 cfs" to "12.4 cfs."	Editorial

Revision 3

Section	Changes
1.1; Figures 1.1-1 & Figures 1.1-2	Revised to reflect the change from ESBWR to US-APWR technology. Added footnote to provide clarification for "msl" datum to "NGVD 29" datum.
Table 1.2-1	Revised to reflect the change from ESBWR to US-APWR technology.
1.3; Table 1.3-1	Revised to reflect the change from ESBWR to US-APWR technology. Revised 1.3.3 to update the list of new and significant information. Added 1.3.3.3 to described new and significant processes for ER revisions. Revised Table 1.3-1 to provide update to IFIM study description.
2.4	Revised to reflect the change from ESBWR to US-APWR technology. Revised 2.4.1.5 to reference a subsequent habitat survey. Revised 2.4.1.6 and 2.4.1.7 to discuss a letter regarding two plants of interest, and added related references.

Revision 3 *(continued)*

Section	Changes
2.7; Tables 2.7-1 thru 2.7-12	Revised to reflect the change from ESBWR to US-APWR technology. Updated to reflect the latest sensitive receptors and χ/Q inputs from US-APWR.
Chapter 3; Tables 3.0-1 thru 3.0-7	Revised to reflect the change from ESBWR to US-APWR technology. Changed values for site and design characteristics and accident analyses and results.
3.1	Revised to reflect the change from ESBWR to US-APWR technology. Clarified area required for UHS cooing tower basins and cooling towers' height.
3.2	Revised to reflect the change from ESBWR to US-APWR technology.
3.3; Table 3.3-1	Revised to reflect the change from ESBWR to US-APWR technology. Changed chemicals, applications (dosages) and subsystem descriptions.
3.6	Revised to reflect the change from ESBWR to US-APWR technology.
3.7	Revised to reflect the change from ESBWR to US-APWR technology. Deleted description of intermediate switchyard from Section 3.7.1.
3.8	Revised to reflect the change from ESBWR to US-APWR technology. Revised to include the RADTRAN results.
4.3	Revised to reflect the change from ESBWR to US-APWR technology. Revised 4.3.1.1 and 4.3.1.2 to discuss two plants of interest and added related references.
4.4	Revised to reflect the change from ESBWR to US-APWR technology. Revised to add commitment to address the communications plan.
Appendix 4A; Figures 4A-1 & 4A-2	Revised to reflect the change from ESBWR to US-APWR technology. Revised to add discussion of, and references to plant-specific habitat survey conducted for the additional property, and the planned identification survey. Revised Figure 4A-2 to include plant-specific habitat survey.
Appendix 4B; Figure 4B-1	Revised to reflect the change from ESBWR to US-APWR technology. Revised to include the results of the plant specific habitat survey that found a potential small whorled pogonia habitat on-site.
5.3	Revised to reflect the change from ESBWR to US-APWR technology. Added discussion of UHS visible plume length.

Revision 3 *(continued)*

Section	Changes
5.4; Tables 5.4-1 thru 5.4-8	Revised to reflect the change from ESBWR to US-APWR technology. Revised release activities, distances, dose calculation values.
5.8; Figures 5.8-1, 5.8-2, & 5.8-3	Revised to reflect the change from ESBWR to US-APWR technology.
5.9	Revised to reflect the change from ESBWR to US-APWR technology.
5.10; Tables 5.10-1 thru 5.10-6	Revised to reflect the change from ESBWR to US-APWR technology.
7.2	Revised to reflect the change from ESBWR to US-APWR technology. Revised to incorporate the severe accident analysis (MACCS2) for the US-APWR.
7.1; Tables 7.1-1 thru 7.1-12	Revised to reflect the change from ESBWR to US-APWR technology.
7.3	Revised to reflect the change from ESBWR to US-APWR technology.
10; Tables 10.1-1 thru 10.4-2	Revised to reflect the change from ESBWR to US-APWR technology.

Revision 2

Section	Changes
1.1.1, 1.3.3, Figure 1.1-1, 1A, 2.2.1, 2.2.2, 2.3.1, 2.4.1, 2.4.1.2, 2.4.1.3, 2.4.1.5, 2.4.1.6, 2.4.1.8, 4.1, 4.1.3, 4.2, 4.2.1.1, 4.2.1.2, 4.3, 4.3.1.3, 4.3.2.1, 4A, Figures 4A-1 & 4A-2, Table 10.1-1	Added information on additional property construction utilization and impacts to wetlands; revised Site Utilization Plan; added statements in associated sections to reference Appendix 4A.
1.1.1, 1.3.3, Table 1.2-1, 1A, 2.4.1.6, 2.5.3.3, Section 2.5 References, 3.4, 4.1, 4.1.2, 4.1.3, 4.2.1.1, 4.3.1.4, 4.4, 4A, 4B, 5.6.3.4, 5.10, 5.10.1.4, 5.10.1.5, 5.10.1.6, Section 5.10 Reference, Table 5.10-3, Tables 10.1-1 & 10.1-2	Editorial changes.
1.3.3, 2.2.1, 2.5, 2.5.1, 2.5.2, 2.5.3, 2.5.4, Section 2.5 References, 4.1.3	Added information on historic and cultural resources within the transmission corridor.
Table 1.2-1	Updated status of permitting activities.
Table 1.2-1	Completed definition of acronyms.

Revision 2 *(continued)*

Section	Changes
Table 1.3-1, 5.10.1.1	Updated status of IFIM study; added summary description of IFIM study.
1.3.3, 1A, 4.6, 3.7.2, 5.6.3.4, Table 10.1-1	Added description of mitigation measures associated with the transmission corridor.
1.3.3, 1A, 2.3.1, 2.4.1, 2.5, 4.1.3, 4.3.1.2, 4.4, 4.6, Table 10.1-1	Added new information on historic and cultural resources and wetlands within the heavy haul route and mitigation measures to prevent impacts to historic and cultural resources, and to wetlands.
1A, 2.4.1.8, 5.8, 5.10.1.4, 5.10.1.5, 5.10.1.6, 9.4, Table 10.1-2	Addressed nonhydrological impacts from mitigating actions based on the results of the IFIM study, including the 3-inch in lake level. Aligned narratives among EPP, 5.10, and 10.1.
1A, 4.6	Added mitigating actions identified in the Draft Supplemental Environmental Impact Statement
1A, 4.7, 4B	Added 4B to address site separation activities. Added 4.7, Cumulative Impacts. Corrected EPP Table 1 to be consistent with 4B.
Table 3.0-2	Updated the evaporation rate characteristic value.
3.4, 5.2, 5.3, 5.10, Tables 5.10-1 thru 5.10-6, Figures 5.10-1 thru 5.10-4, Tables 10.4-1 & 10.4-2	Added descriptions of mitigating actions based on the results of the IFIM study, including the 3-inch lake level increase.
1.1.6, 1A, 2.2.1, 2.3.1, Section 2.3 References, 2.4.1, 4.3.1.4, Section 4.3 References, 4A, 5.10.1.1, 5.10.1.4, 5.10.1.5, 5.10.1.6, Table 5.10-1	Updated construction start date information. Corrected EPP Table 1 to be consistent with 2.2.1 and 4A. Added reference to substantiate 2.3.1. Provided pointer in 2.4.1 to location of new information. Provided basis for section conclusion statement 4A.5. Incorporated IFIM comment into 5.10, clarifying statements of hydrologic alterations, aquatic ecology impact, future shoreline wetland mitigation evaluations, and added missing footnotes to Table 5.10-1.

Revision 1

Section	Changes
Section 1.1 References, EPP References; Section 2.3 References, Section 2.4 References, Section 3.6 References, Section 3.7 References, Section 3.8 Reference, Section 4.1 Reference, Section 4.2 Reference. Section 5.2 Reference, Section 5.6 References, Section 5.9 References, Section 7.1 References, Section 7.3 References, Section 8.0 References, Section 8.1 References, Section 8.2 References, Section 8.3 References, Section 8.4 References, Section 9.2 References, Section 10.4 References	Editorial changes.
1.1.6	Revised estimated key milestones.
Table 1.2-1, 1.3.4, Table 1.3-1, Chapter 3, Tables 3.0-1 thru 3.0-7, 3.1, 3.2, 7.3.3	Updated to reflect ESP-003; editorial and clarifying changes.
1.3.1	Updated to reflect ESP-003; editorial changes.
Table 1.3-1	Updated status of IFIM study.
Figures 1.1-1 & 1.1-2	Updated site utilization figures to align with DCD R5.
EPP, Table 1, 2.5, 8.0.1.1, 8.3.1.3	Editorial changes.
Table 2.3-1	Reflected new lake water sample data.
2.7, 2.7.6	RAI NA3 02.03.05-1, χ/Q and D/Q Values
2.7.6, Table 2.7-1	Updated source-to-receptor distances, χ/Q values.
2.7.6, Tables 2.7-1 & 2.7-2, 5.4.2.2, Tables 5.4-4 thru 5.4-6	RAI NA3 02.03.05-2, Clarification of χ/Q and D/Q Values
2.7.6, Tables 2.7-5 thru 2.7-12	RAI NA3 02.03.05-3, χ/Q and D/Q Values Out to 50 Miles
Table 3.0-1, Post-Accident	Corrected reference to DBA dose consequences.

Revision 1 *(continued)*

Section	Changes
Tables 3.0-1 & 5.4-4	Added "undepleted" or "depleted" to descriptions; editorial corrections; reflected new doses to MEI (Table 3.0-1). Editorial clarifications (Table 5.4-4).
Table 3.0-2, Structure Height	Updated tallest structure information.
Tables 3.0-2 thru 3.0-6a; 7.1.3, 7.1.4, Tables 7.1-1 thru 7.1-10	Updated source terms in plant parameter and activity release tables to align with DCD R5.
3.6.1	Clarified copper-presence explanation.
3.6.1, Table 3.6-1	Revised the copper and tributyltin values and the associated explanatory statement.
3.7.1	Revised 500 kV connection to Ladysmith line.
4.1.4, 4A	Revised to describe additional property per Dominion Letter NA3-08-108 (Proprietary).
4.3.1.1, Section 4.3 References	Reflect results of new wetlands impacts, wildlife and cultural resources assessments.
5.4.2.2, Tables 5.4-3, 5.4-4, 5.4-5, 5.4-6, 5.4-7, & 5.4-8	RAI NA3 12.02-1, Update Commitment to Final Version of NEI 07-03
5.4.2.3	Incorporated discussion of Units 1 & 2 direct radiation contribution.
5.4.2.3, Table 5.4-6	Changed ISFSI dose contribution, and changed existing units and site total doses.
5.4.3	Updated discussion of liquid and gaseous effluent dose impacts to MEI due to operation of Units 1, 2, and 3 and the ISFSI. Added discussion of Unit 3 operational liquid and gaseous effluents on the population within 50 miles.
Tables 5.4-4 & 5.4-7	RAI NA3 12.02-11, Clarify Information In Section 12 Tables
Table 5.4-6	RAI NA3 12.02-12, Dose Contributions
Section 5.6 References, Section 8.0 References, Section 8.1 References, Section 8.2 References, Section 8.3 References, Section 8.4 References, Section 9.2 References, Section 10.4 References	Editorial corrections (deleted web addresses).
7.1.4, Table 7.1-9	Editorial correction.
8.2.1.1, 8.2.1.2.1, 8.2.1.2.3, 8.2.1.2.4, 8.2.2.2.1, Section 8.2 References	Deleted references 9 and 17 and renumbered/corrected citations accordingly.

Revision 1 *(continued)*

Section	Changes
Table 9.2-4a	Added table from RAI response ER NA3-08-079R (coal combustion).
	Typographical correction. Updated PM10 emission rate.
Table 9.2-10	Typographical correction.
Tables 10.4-1 & 10.4-2	Incorporated revisions per RAI response ER NA3-08-079R (cost benefit).

PART 3 - ENVIRONMENTAL REPORT
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PART 3: ENVIRONMENTAL REPORT

Chapter 1 Introduction

This Applicants' Environmental Report-Combined License Stage is submitted pursuant to 10 CFR 51.50(c) to provide environmental information supporting the application of Virginia Electric and Power Company, doing business as Dominion Virginia Power (Dominion or DVP), for a combined construction permit and operating license for a third nuclear unit at the North Anna Power Station (NAPS).

The environmental impacts of constructing and operating new nuclear units at NAPS were previously assessed in North Anna Early Site Permit Application, Part 3, Environmental Report (ESP-ER) (Reference 1), and in NUREG-1811, Final Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna Site (FEIS) (Reference 2). In accordance with 10 CFR 51.50(c)(1), this Applicants' Environmental Report - Combined License Stage incorporates by reference the assessment of environmental issues that were resolved in the ESP proceeding and provides, where necessary, the following supplemental information:

- Information demonstrating that the design of the facility falls within the ESP site characteristics and design parameters;
- Information resolving any significant environmental issue identified by the NRC that was not resolved in the early site permit proceeding;
- Any new and significant information for issues related to the impacts of construction and operation of the facility that were resolved in the early site permit proceeding;
- A description of the process used to identify new and significant information regarding the NRC's conclusions in the ESP environmental impact statement; and
- Demonstration that relevant environmental terms and conditions for the early site permit will be satisfied by the date of issuance of the combined license, or for requirements applicable to activities that may continue beyond COL issuance, would be appropriately included as terms and conditions of the combined license.

1.1 The Proposed Action

This section provides a description of the proposed action, the applicants, site location, and the selected design.

The proposed action is the issuance of a combined construction permit and operating license (COL) for a new nuclear unit (Unit 3) at the North Anna Power Station (NAPS). Unit 3 would be a 4500 megawatt thermal (MWt) ESBWR.

The purpose and need for the proposed action is to provide additional baseload power for residential and industrial customers in the region served by Dominion. Additional purposes of proposed Unit 3 are to maintain fuel diversity in this region, reduce dependence on imported power, leverage Dominion's existing nuclear facilities, and to promote the regional economy, while not contributing to CO_2 emissions.

1.1.1 The Applicant and the Owner

Dominion is the applicant for the COL addressed in this environmental report. Dominion holds sole title to the portion of NAPS on which Unit 3 will be located. The remainder of the NAPS site is owned by Dominion and Old Dominion Electric Cooperative as tenants in common. These companies also own all land outside the NAPS site boundary that forms Lake Anna, up to Elevation 255 ft msl[1]. Dominion is the licensed operator of the existing units, with control of the existing site and facilities and the authority to act as ODEC's agent. In addition, Dominion owns additional property contiguous with the NAPS site, which will provide additional space for Unit 3 construction support activities.

1.1.2 Site Location

The portion of the North Anna site on which Unit 3 will be located is the same as the ESP site described and evaluated in the ESP-ER and FEIS. The NAPS site is located on a peninsula on the southern shore of Lake Anna, approximately 5 miles upstream of the North Anna Dam. The NAPS site is located in Louisa County, Virginia, near the town of Mineral.

The portion of the NAPS site on which Unit 3 will be located is shown on ESP-ER Figure 1.1-1. Figures 1.1-1 and 1.1-2 show the location of Unit 3 buildings and equipment within the ESP proposed facility boundary (ESP plant parameter envelope) (see ESP-ER Figure 2.1-1) as well as the cooling tower area, switchyard expansion, spoils and overflow storage, temporary batch plant, construction laydown areas, and temporary construction parking.

1.1.3 Reactor Information

In the ESP-ER, the reactor technology to be used had not been selected. Since that time, Dominion has selected the ESBWR as the reactor technology to be constructed and operated at the ESP site. This ER addresses one unit (Unit 3) on the site. Details of the Unit 3 ESBWR design are provided in the FSAR.

1.1.4 Cooling System Information

As described in the ESP-ER, the cooling system for Unit 3 will be a closed-cycle, combination dry and wet cooling tower system, with make-up water supplied from Lake Anna. Make-up water will be withdrawn from the North Anna Reservoir through a new intake structure located on a cove on the south shore of the lake, originally planned for the intake of the never-constructed Units 3 and 4. This new structure will be adjacent to the existing units' intake structure. Cooling system discharges for

1. The designation msl (mean sea level) for water level is referenced to the National Geodetic Vertical Datum 1929 (NGVD29).

the existing units and the Unit 3 wet cooling tower blowdown will be sent to the Waste Heat Treatment Facility (WHTF) via the existing discharge canal.

1.1.5 Transmission System Information

At the ESP stage, it was expected based on an initial evaluation that any two of the existing 500 kV transmission lines, together with the 230 kV transmission line, would have sufficient capacity to carry the total output of the existing units and the new units. Subsequently, a system study (load flow study) has been performed that models these lines with the new unit's power contribution. The results of the load flow study and import/export studies indicate that a new 500 kV transmission line and other system reinforcements will be required for grid reliability in association with the interconnection of new Unit 3. The new line will be installed on new transmission towers in the existing corridor between the North Anna Substation and the Ladysmith Switching Substation. Further information is provided in Section 3.7.

1.1.6 Construction Start Date

Subject to required regulatory approvals and a decision to build, the following are estimated dates related to construction and operation of Unit 3:

Potential Safety Related Construction Start 2019

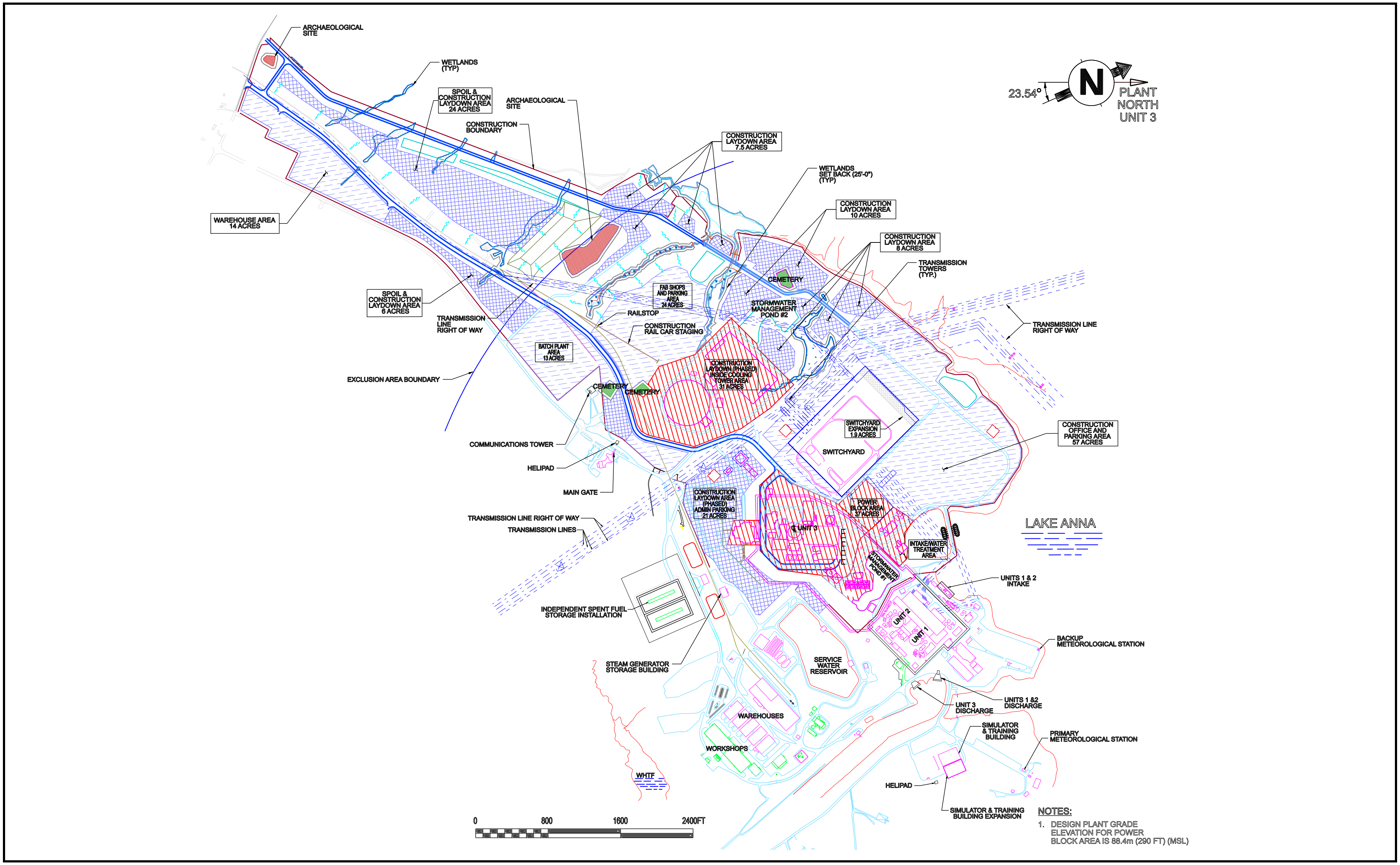
Fuel Load: 2023

Section 1.1 References

1. Dominion Nuclear North Anna, LLC, "North Anna Early Site Permit Application, Part 3 – Environmental Report," Revision 9, September 2006.

2. U.S. Nuclear Regulatory Commission, "Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna ESP Site," NUREG-1811, December 2006.

Figure 1.1-1 Site Utilization Plan



Security-Related Information Withheld Under 10 CFR 2.390

Figure 1.1-2 Site Plan With Building Legend

1.2 Status of Reviews, Approvals, and Consultations

Numerous reviews, approvals, and consultations will be required for the construction and operation of new Unit 3. Table 1.2-1 provides a list of the environmental-related authorizations, permits, and certifications required by federal, state, regional, and local agencies for activities related to the construction and operation of Unit 3 at the NAPS site.

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
Federal Aviation Administration (FAA)	49 USC 1501	Construction Notice			Notice of erection of structures (if >200 feet) potentially impacting air navigation	Received "Determination of no hazard to air navigation" 4/13/08. Received antenna tower approval 2008. Other extensions or determinations to be applied for as needed.
Lake Anna Special Area Plan Committee	N/A	Conditional Land Use Approval	N/A	N/A	Local land use approval – Lake Overlay District, on as-needed basis only	Consultation with Lake Anna Advisory Committee expected to be conducted following issuance of COL.
Nuclear Regulatory Commission (NRC)	Atomic Energy Act (AEA), 10 CFR 51, 10 CFR 52.17	EIS	N/A	N/A	Environmental effects of construction and operation of a reactor	Under NRC Review
NRC	10 CFR 52, Subpart C	Combined License			Combined construction permit and operating license for a nuclear power facility	Under NRC Review
NRC	10 CFR 52, Subpart A	Early Site Permit	ESP-003	11/27/ 2027	Approval of the site for one or more nuclear power facilities, and approval of limited construction as per 10 CFR 50.10(e)(1)	Received November 2007
NRC	10 CFR 30	Byproduct Materials License			NRC license to possess special nuclear materials	To be issued with COL
NRC	10 CFR 70	Special Nuclear Materials License			NRC license to possess nuclear fuel	To be issued with COL
Virginia State Corporation Commission (SCC)	VA Code 56-265.2 and 56-46.1				Certificate of public convenience and necessity	Necessary for construction

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
U.S. Army Corps of Engineers (USACE)	Federal Water Pollution Control Act (FWPCA)	Section 404 Permit	10-V 1256/ NAO-2008-2534	9/30/26	Disturbance or crossing wetlands, streams or navigable waters	Received permit Sept 2011
USACE/Virginia Marine Resources Commission (VMRC)	Rivers and Harbors Act	Section 10 Permit	10-1256	9/27/16	Impacts to navigable waters of the U.S. (would also include overhead transmission line crossings)	Received permits Sept 2011
U.S. Fish & Wildlife Service (USFWS)/USACE	Endangered Species Act	Consultation regarding potential to adversely impact protected species	N/A	N/A	Concurrence with no adverse impact or consultation on appropriate mitigation measures	Concurrence received in connection with Section 404 permit issued Sept 2011
	Migratory Bird Treaty Act				Adverse impact on protected species (e.g., eagles, ospreys) and/or their nests, if applicable	
Virginia Department of Environmental Quality (VDEQ)	Clean Air Act 9 VAC 5-20-160	Registration (air emission)			Annual update report of air emissions	Expected to be submitted with (Air) Operating Permit application. Schedule being evaluated
VDEQ	9 VAC 5-80-800	State Operating Permit			Construction and operation of minor air emission sources	Schedule being evaluated
VDEQ	9 VAC 5-50-60 et seq.	Control and Abatement of Air Pollution			Fugitive dust control	Expected to be submitted with (Air) Operating Permit application. Schedule being evaluated

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
VDEQ	9 VAC 5-80-1100 et seq.	Permits for New and Modified Stationary Sources			Permit to install fuel burning equipment (e.g., boilers and generators)	Expected to be submitted with (Air) Operating Permit application. Schedule being evaluated
VDEQ	CWA, Section 402; 9 VAC 25-10/ 9 VAC 25-820/ 9 VAC 25-790	Virginia Pollutant Discharge Elimination System Permit (VPDES)/ Nutrient General permit/ Sewage treatment Certificates			Regulate limits of pollutants in liquid discharge to surface water	Expected to be submitted for construction sewage discharge permit and operational discharge permit, schedule being evaluated. Certificate to construct for site separation modifications to the existing Units 1/2 sewage treatment plant obtained 6/21/11; for certificates to construct & operate Unit 3 sewage treatment plants, schedule being evaluated
Virginia Department of Conservation & Recreation (VDCR)	FWPCA 4 VAC 50-60-10	Virginia Stormwater Management Program General Permit Registration Statement for stormwater discharges from Construction Activities	VAR 10-10-10574	06/30/14	General permit to discharge stormwater from land-disturbing and/or site construction activities	Received five-year general permit for site separation activities in 2009
VDEQ	9 VAC 25-210	Virginia Water Protection Permit	10-1256	4/14/26	Permit to dredge, fill, discharge pollutants into or adjacent to surface water. Joint Permit Application with USACE Section 404 permit	Received permit April 2011

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
VDEQ	FWPCA	Section 401 Certification (VWP Individual Permit serves as the 401 certification)	10-1256	4/14/26	Compliance with water quality standards	Received permit April 2011
VDEQ	9 VAC 25-210	Virginia Water Protection Individual Permit	10-1496	4/14/26	Permit to withdraw water from Lake Anna for construction	Received permit April 2011
VDEQ	9 VAC 25-210	Virginia Water Protection Individual Permit			Permit to withdraw water from Lake Anna for operation of Unit 3 & raise the lake level 3 inches	Received permit April 2012
VDEQ (lead agency)	Virginia Coastal Resources Management Program	Consistency determination (Coastal Zone Management Act)	N/A	N/A	Compliance with Virginia Coastal Program	Concurrence received May 2011
Virginia Department of Historic Resources (VDHR)	National Historic Preservation Act, 36 CFR 800	Cultural Resources Survey/Review	N/A	N/A	Evaluate area of potential effects for historic/cultural resources. If resources are present, complete Section 106 consultations as needed.	Large component transport route (LCTR) cultural resources evaluation submitted to VDHR July 2011. “No Adverse Effect” letter received July 2011 regarding eligible cultural resources at Walkerton Landing
Virginia Department of Transportation (VDOT)	24 VAC 30 et seq.	Consultation			Equipment transport routes, employee and/or public access routes, level-of-service review, transportation management plan	Began 2011, consultations continue with project needs and schedule

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
VMRC		VMRC Permit	10-1256	9/27/16	Permit to fill submerged land; Joint Permit Application with USACE Section 404 permit	Received permit Sept 2011
	VA Code 28.2-1280 et seq.				Submerged bottomlands	
	VA Code 28.2-1300 et seq.				Wetlands	
Virginia Department of Health (VDH)	12 VAC 5-590	Permit			Water supply well, as needed	Received permit Sept. 2010
Louisa County	Code of Ordinances Chap. 66	Permit		5/16/15	Water supply well, as needed	Received permit Nov. 2010
Louisa County	Code of Ordinances Chap. 38	Land Disturbing Permit	ESCP 30-80		Land disturbing activities associated with construction activities.	Renewal permit ESCP 30-80 for site separation in 2009
Louisa County	4 VAC 50-30					Received ESCP 30-80 in 2009 to support land disturbance beginning in 2010. Updated for additional phased construction-related activities in 2011
Louisa County	Code of Ordinances Chap. 18	Permit			Buildings and occupancies, as needed	Submitted and received for site separation in 2010-2013; others to be determined

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. [a]	Expiration Date [a]	Activity Covered	Status
King William Wetlands Board		Wetlands Permit	10-1256	2026	Wetlands impacts associated with off-loading facilities	Received permit June 2011

a. Licenses and permits will be applied for and received at the appropriate time, including renewals as appropriate.

N/A: Not applicable. No specific permit number or expiration date is associated with this consultation.

1.3 Report Contents

This report follows the same table of contents as the ESP-ER. Where a topic was previously addressed and resolved in the ESP proceeding, and no new and significant information has been identified, this report identifies the sections of the ESP-ER and FEIS that address the topic and states that no new and significant information has been identified. However, where new and significant information has been identified, the report provides the supplemental information required by 10 CFR 51.50(c)(1), as discussed in the following sections.

1.3.1 Information to Demonstrate That the Facility Design Falls Within the Site Characteristics and Design Parameters in the ESP

In accordance with the first row of FEIS Table J-1, Table 3.0-1 provides an evaluation of Unit 3 site characteristics against the ESP site characteristics identified in FEIS Table I-1.

In accordance with the second row of FEIS Table J-1, Table 3.0-2 provides an evaluation of Unit 3 design characteristics against the ESP plant parameters identified in FEIS Table I-2 and ESP Table D-1.

See also FSAR Table 2.0-201 which includes an evaluation of ESBWR DCD site parameters, ESP site characteristics, and ESP design parameters.

1.3.2 Information to Resolve any Significant Environmental Issues that Were Not Resolved in the ESP Proceeding

Several issues were not resolved in the ESP proceeding. The issues applicable to Unit 3 and previously identified as unresolved in the FEIS are listed below along with the section of this report in which they are addressed:

- Need for Power (Chapter 8)
- Energy Alternatives (Section 9.2)
- Water Quality (Sections 3.6, 5.2)
- Alternatives to Mitigate Severe Accidents (Sections 7.2, 7.3)
- Chronic Health Impacts of Electromagnetic Fields (Section 5.6)
- Decommissioning impacts (Section 5.9)
- Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment (Section 10.3)
- Benefit-Cost Balance (Section 10.4)

1.3.3 New and Significant Information

In accordance with 10 CFR 51.50(c)(1)(iii), this ER provides new and significant information for various issues related to the impacts of construction and operation of the facility that were resolved in the ESP proceeding:

- New 500 kV Transmission Line (Sections 1.1.5, 2.2.2, 2.4.1, 2.5.3.3, 3.7, 4.1.2, 4.1.3, 4.2.1, 4.3, 4.4, 4.6, 5.1.2, 5.6, 9.4, 10.1)
- Revised Long-Term χ/Q Values for Changes in Receptor Locations (Sections 2.7.6, 5.4)
- Offsite Road/Rail Transport of Large Components (Sections 2.3.1, 2.4.1, 2.4.1.8, 2.5, 2.5.3.5, 4.1.1, 4.1.3, 4.3.1.4, 4.6)
- Change in Potentially Impacted Ephemeral Streams (Section 4.2.1.1)
- Revised Liquid Effluent Release Activities (Section 5.4)
- Separate Sanitary Waste Facility for Unit 3 (Sections 3.6, 5.5)
- Revised Accident Source Terms (Sections 2.7.5, 7.1)
- Mitigating Actions Based on Results of IFIM study (5.10.1)
- Acquisition and use of additional property (Section 4.1.4, Appendix 4A)
- Site Separation Activities (Appendix 4B)
- Plant-specific habitat surveys (Sections 2.4.1.6, 2.4.1.7, 4.3.1.1, 4.3.1.2, Appendix 4A, Appendix 4B)
- Design Basis Accidents (Section 7.1)
- Seismological Conditions and Impacts (Sections 2.6.2.2.1 and 2.6.4.2.1)
- Radiation Exposure to Construction Workers (Section 4.5)

In accordance with 10 CFR 51.50(c)(1)(iv), a description of the process used to identify new and significant information regarding the NRC's conclusions in the FEIS is provided below.

1.3.3.1 Definitions

The following definitions apply to the new and significant process:

1. "Key inputs" means those assumptions and inputs, explicitly identified or implied, that were considered in the environmental review, either by the NRC Staff to support its findings and conclusions in the FEIS or in preparation of the ESP-ER.

   The FEIS is the primary document that was reviewed for key inputs used by the NRC Staff in its evaluations. These FEIS key inputs identify the main sources of information that were considered for whether or not there could be new information potentially affecting a finding or conclusion regarding an environmental impact. The representations and assumptions relied upon by the NRC Staff during its review of the ESP-ER and development of the FEIS are identified in each section of the FEIS and are also listed in FEIS Appendix J.

   In addition to the review of FEIS for key inputs, the ESP-ER was also reviewed to identify any relevant key inputs for which new information is available that may bear on the FEIS impact evaluations.

2. "New" in the phrase "new and significant information" is any information that was both: 1) not considered in preparing the ESP-ER or FEIS, and 2) not generally known or publicly available during the preparation of the FEIS. See 72 FR 49431.

3. For new information to be "significant," it must be material to the issue being considered, that is, it must have the potential to affect the finding or conclusions of the NRC Staff's evaluation of the issue. See 72 FR 49431.

The NRC has established three significance levels for environmental impacts: SMALL, MODERATE, and LARGE. In general, one of these three significance levels was assigned to each impact evaluated and resolved in the FEIS. New information was considered significant if it had the potential to change an NRC-assigned level of significance; that is, from SMALL to MODERATE or from MODERATE to LARGE for adverse impacts.

1.3.3.2 Steps of the New and Significant Information Process

The "new and significant information process" is a multi-step process used to identify new and significant information for inclusion in this ER per the requirements of 10 CFR 51.50(c)(1)(iii). The new and significant information process is documented in procedures and was implemented by qualified personnel including researchers, subject matter experts, licensing specialists, and engineering and environmental professionals.

Figure 1.3-1 is a flowchart that illustrates the steps of the new and significant information process. Process steps are described below.

Step 1: Identify issues that are resolved in the FEIS, and discussed in the ESP-ER, related to the topic being addressed.

Identify if the issue being reviewed was resolved in the FEIS. In general, an issue is resolved if an impact level of SMALL, MODERATE, or LARGE was assigned in the FEIS for the issue. In a few cases, the FEIS states conclusions in terms specific and appropriate to the subject area. (Issues that were identified as unresolved in the FEIS are identified in Section 1.3.2.)

Step 2: Document key inputs from the FEIS and ESP-ER.

For resolved issues, identify those FEIS sections and corresponding ESP-ER sections for the issue being addressed. Within these sections, identify the key inputs considered relevant to the resolved issue (used to make the FEIS determination). Document the identified key inputs.

Step 3a: Screen EIS key inputs.

Perform a screening of the FEIS key inputs to determine whether there is new information or whether there is a need to perform further research to determine if new information related to the key input exists. Give consideration to the potential for change of the input given the amount of time passage from FEIS completion to development of this ER. Document the results of the review by identifying whether or not new information exists for a given key input. If the existence of new information is not known, assume that new information may exist.

Screening reviews were performed by a review team consisting of subject matter experts, licensing specialists, engineering and environmental personnel, and other knowledgeable individuals.

Step 3b: Identify other and/or new key inputs.

Identify any other key inputs from the ESP-ER, subject matter expert's or review team's experience, or external documents, which were not otherwise identified in the Step 2 review for key inputs. Screen these key inputs in the same manner as described in Step 3a.

Step 4: Determine appropriate tasks to identify new information.

If it is not known whether new information exists for a key input, or the extent of the new information is not readily apparent, determine the appropriate actions to take to evaluate if new information exists for the key input.

Step 5: Perform actions identified in Step 4.

Perform the actions identified in Step 4, and document the resulting conclusion by identifying whether or not new information exists for a given key input. Describe the rationale used to arrive at this conclusion. Include references, as appropriate, to support the rationale used.

Step 6: Conduct significance evaluation.

If new information is found for any key input, evaluate the significance of the new information for the key input identified. Document the results of the significance evaluation, including whether or not the new information is determined to be significant. Refer to external documentation where appropriate.

Step 7: Address items identified as new and significant information in the appropriate section of the COLA ER.

For information identified as "new and significant" in Step 6, provide a description and evaluation of the information in the appropriate sections of this ER.

1.3.3.3 New and Significant Information Identified for COLA ER Revisions

New information which has the potential to affect the findings or conclusion of the NRC Staff's evaluation of an issue is evaluated to determine the significance of the new information relative to each applicable section. This process to document the assessment of new project-related information is implemented by qualified personnel similar to the process described in Section 1.3.3.2 unless the topic is clearly significant and appropriate for inclusion in a COLA ER revision.

1.3.4 Environmental Terms and Conditions

In accordance with 10 CFR 51.50(c)(1)(v), Table 1.3-1 identifies relevant environmental terms and conditions listed in the ESP (ESP-003 in Docket No. 52-008) and demonstrates that they will be satisfied by the date of issuance of the combined license or, for requirements applicable to activities that may continue beyond COL issuance, would be appropriately included as terms and conditions of the combined license. Table 1.3-1 also identifies those conditions that apply only to preconstruction activities if undertaken prior to COL issuance and are not prerequisites to COL issuance.

1.3.5 Commitments and Supplemental Information

In addition to the content requirements of 10 CFR 51.50(c)(1), the following information is provided in this ER to address commitments made in the ESP-ER or to provide supplemental information regarding items in the FEIS:

- Status of IFIM study (Table 1.3-1)
- Transmission system load flow study (Sections 3.7.2, 4.1.2)
- Visual impact study (Sections 3.1, 5.8)
- Description of switchyard upgrades (Section 3.7.1)

- Impacts of crud and activation products on spent fuel transportation accident risks (Section 3.8.2)
- Confirmatory evaluation of fogging, icing, and salt deposition (Sections 5.3, 5.8)
- Maximum annual occupational dose (Section 5.4)
- Confirmatory evaluation of cooling tower noise (Section 5.8)
- Description of Meteorological Monitoring Data Recording System (Section 6.4)
- Estimate of construction materials (Section 10.2)

Table 1.3-1 ESP Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.D	The values of plant parameters considered in the environmental review of the application and set forth in Appendix D to this ESP are hereby incorporated into this ESP.	The ESP plant parameters are described and evaluated against Unit 3 design characteristics in Table 3.0-2.
3.F(1)	The holder of this ESP may perform the activities authorized by 10 CFR 52.25, “Extent of Activities Permitted,” only insofar as the site redress plan describes such activities. The holder of this ESP may perform activities not described in the site redress plan only with prior NRC approval. A request to perform such activities shall describe how such activities will be redressed, and, if the request is granted, the site redress plan shall be deemed to include this additional description of site redress.	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.
3.F(2)	The holder of this ESP may change the site redress procedures set forth in the site redress plan in Appendix E without obtaining Commission approval provided that the changes do not decrease the effectiveness of the plan.	This ESP condition is applicable to activities that may continue beyond COL issuance, and is therefore appropriate for inclusion as a condition of the combined license.
3.F(3)	The permit holder shall obtain the right to implement the site redress plan set forth in Appendix E before initiating any activities authorized by 10 CFR 52.25.	As the owner of the Unit 3 site and entity in control of NAPS, Dominion possesses the right to implement the site redress plan. See FSAR Section 2.1.2.1.
3.G	The permit holder shall notify the NRC Regional Administrators for Region II and the operator of North Anna Power Station of the permit holder’s plans to begin the site preparation and preliminary construction activities described in the site redress plan at least 120 days before commencement of such activities, and shall certify in that notification to the NRC that it has obtained all other permits, licenses, and certifications required for these activities;	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.
3.H	The holder of this ESP shall not perform any site preparation or preliminary construction activities authorized by 10 CFR 52.25 unless such holder obtains the certification required pursuant to Section 401 of the Federal Water Pollution Control Act from the Commonwealth of Virginia, or obtains a determination by the Commonwealth of Virginia that no certification is required and submits the certification or determination to the NRC before commencement of any such activities.	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.

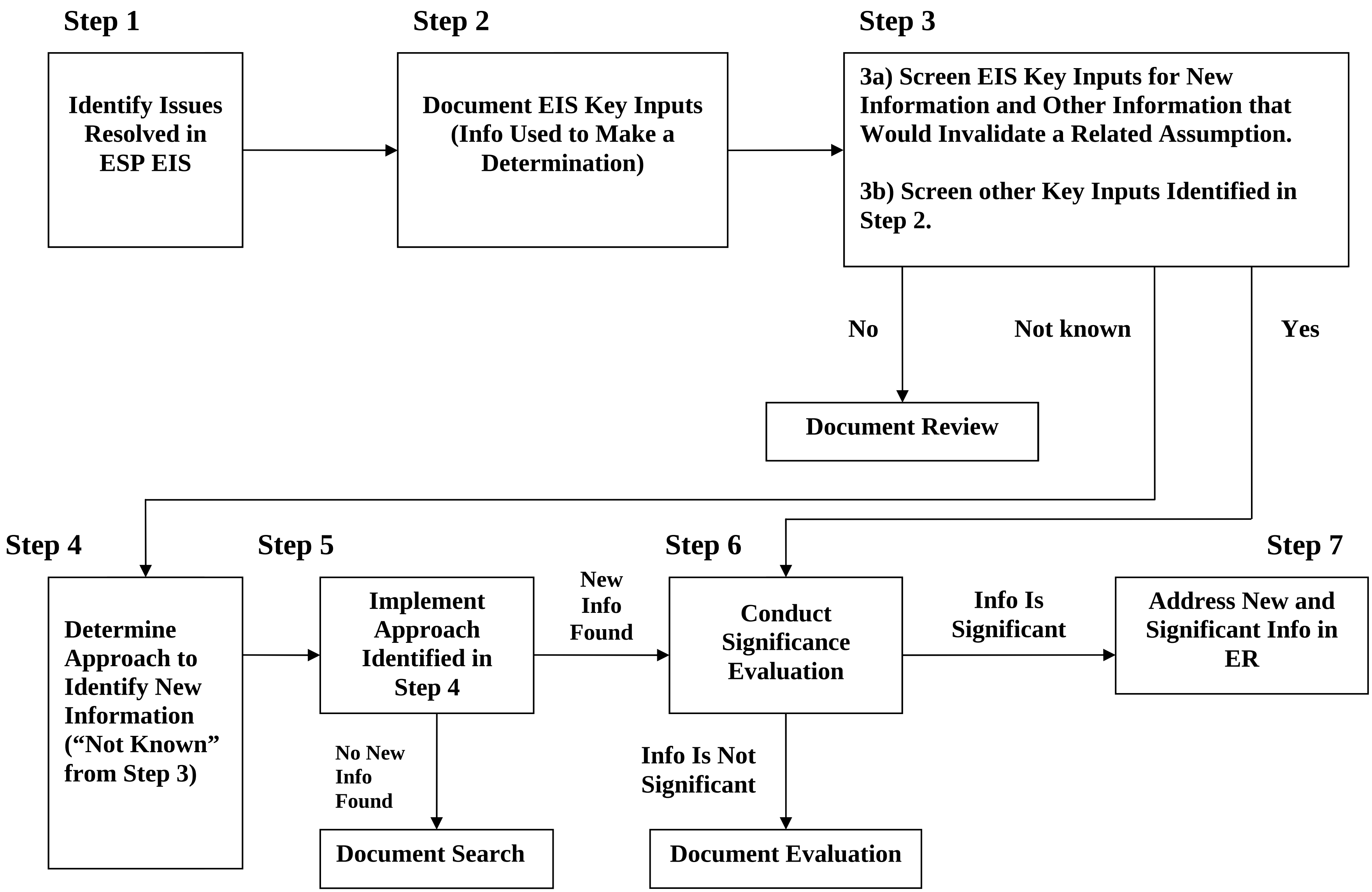
Table 1.3-1 ESP Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.I (1)	Any activities performed pursuant to 10 CFR 52.25 are subject to the conditions for the protection of the environment set forth in the Environmental Protection Plan attached as Appendix F to this ESP.	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be controlled by the Environmental Protection Plan (EPP) proposed in this Application for the COL.
3.I (2)	Dominion shall conduct a comprehensive Instream Flow Incremental Methodology study (IFIM), designed and monitored in cooperation and consultation with the VDGIF and the VDEQ, to address potential impacts of the proposed Units 3 and 4 on the fishes and other aquatic resources of Lake Anna and downstream waters. Development of the scope of work for the IFIM study shall begin in 2007, and the IFIM study shall be completed before issuance of a combined license (COL) for this project. Dominion agrees to consult with VDGIF and VDEQ regarding analysis and interpretation of the results of that study, and to abide by surface water management, release, and instream flow conditions prescribed by VDGIF and VDEQ upon review of the completed IFIM study, and implemented through appropriate State or Federal permits or licenses.	Work on the IFIM study began in January 2006. The final IFIM study report was submitted to VDEQ in October 2009. The IFIM Study Plan had four major components and was focused on a single new unit: 1. IFIM Study Plan Design. The study plan design was conducted in collaboration with Virginia Resource Agencies. The study scope included: a. designated North Anna River and Pamunkey River mileage and zones affected; b. species of concern and habitat parameters needed for life stages; c. a wide range of flows with parameters monitored and modeled; d. river recreational impact; and e. Lake Anna water level impacts on shoreline and wetlands. 2. Field Data Collection. Field data collection began in Summer 2007 and was completed in Spring 2008. 3. Analysis Methodology. The analysis methodology was developed in collaboration with state agencies following data collection. The analysis began in Summer 2008 and was completed in Spring 2009. 4. Interpretation of Analysis and Reporting. This was performed in collaboration with state agencies following completion of the analysis. Mitigating actions based on the results of the IFIM study are described in Section 5.10.1 and support permitting actions listed in Table 1.2-1.

Table 1.3-1 ESP Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.I (3)	The CP or COL applicant will conduct an instream flow incremental methodology study pursuant to the Coastal Zone Management Act consistency determination.	See the description for Condition 3.I (2) above.
3.J	An applicant for a CP or COL referencing this ESP shall develop an Environmental Protection Plan (EPP) for construction and operation of the proposed reactor and include the EPP in the application. The portion of the EPP directed to operation shall include any environmental conditions derived in accordance with 10 CFR 50.36b, “Environmental Conditions.”	The Environmental Protection Plan (EPP) is provided as Appendix 1A to this ER.

Figure 1.3-1 Flowchart of the New and Significant Information Process



1.4 Conformance with Division 4 Regulatory Guides

The supplemental analyses presented in this ER were prepared using the guidance provided in NUREG-1555, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants." NUREG-1555 is the document that guides the NRC Staff's reviews of the information contained in Environmental Reports. The content guidelines outlined in NUREG-1555 are generally consistent with the guidance contained in Regulatory Guide 4.2.

None of the other Division 4 regulatory guides is applicable to the supplemental analyses presented in this ER.

Appendix 1A Environmental Protection Plan

APPENDIX C

TO FACILITY COMBINED LICENSE NO. [XXX-XX]

NORTH ANNA - UNIT NO. 3

DOMINION VIRGINIA POWER

DOCKET NO. 52-017

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

[DATE]

Table of Contents

1. Objectives of the Environmental Protection Plan

The purpose of the Environmental Protection Plan (EPP) is to provide for protection of nonradiological environmental resources during construction and operation of Unit 3. The principal objectives of the EPP are as follows:

(a) To ensure that the facility is constructed and operated in an environmentally acceptable manner, as established by the ESP Final Environmental Impact Statement (FEIS) and COL Supplemental EIS (SEIS) (Reference 1) and (Reference 2)

(b) Coordinate NRC requirements and maintain consistency with other Federal, State, and local requirements for environmental protection

(c) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects

Environmental concerns identified in the FEIS and SEIS that relate to water quality matters or other matters regulated under the Federal Water Pollution Control Act will be governed by the licensee's Virginia Pollutant Discharge Elimination System (VPDES) permit.

2. Environmental Protection Issues

In the ESP FEIS, the staff considered the environmental impacts associated with the construction and operation of reactors at the North Anna ESP site. In the SEIS, the staff supplemented the ESP FEIS to consider issues that were not previously resolved or were affected by significant new information. The objective of this EPP is to ensure that environmental impacts associated with construction and operation of Unit 3 and in accordance with the facility Combined Construction Permit and Operating License (COL) will not exceed in any significant respect the impacts assessed in the FEIS and SEIS.

3. Consistency Requirements

3.1 Construction Activities

The licensee shall take the mitigating actions identified in EPP Table 1 to avoid any unnecessary adverse environmental impacts from construction activities. These mitigating actions are also identified in the following documents:

- ESP-ER (Reference 3)
- Chapter 4.0 of the FEIS (as summarized in FEIS Section 4.10)
- COL ER (Reference 4)
- Chapter 4.0 of the SEIS (as summarized in SEIS Section 4.10)

The licensee shall maintain records of construction activities. These records shall include an assessment of whether the environmental impact of construction activities is consistent with that evaluated in the FEIS and SEIS.

3.2 Operations

The licensee shall take the mitigating actions identified in EPP Table 2 to avoid any unnecessary adverse environmental impacts from facility operation. These mitigating actions are also identified in the following documents:

- ESP-ER
- Chapter 5.0 of the FEIS (as summarized in FEIS Section 5.11)
- COL ER
- Chapter 5.0 of the SEIS (as summarized in SEIS Section 5.12)

3.3 Reporting Related to the VPDES Permit and State Certification

Violations of the VPDES Permit or the State certification (pursuant to Section 401 of the Clean Water Act) shall be reported to the NRC by submittal of copies of the reports required by the VPDES Permit or certification.

Changes and additions to the VPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The NRC shall be notified of changes to the effective VPDES Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The notification of a licensee-initiated change shall include a copy of the requested revision submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the VPDES permit at the same time the application is submitted to the permitting agency.

3.4 Changes

The licensee may make changes in construction activities, make changes in station design or operation, or perform tests or experiments affecting the environment provided such changes, tests, or experiments do not involve an unreviewed environmental question, and do not constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1. Changes in construction activities, changes in plant design or operation, or performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by EPP Section 3.5 are not subject to the requirements of this section.

A proposed change, test, or experiment shall be deemed to involve an unreviewed environmental question if it concerns: a) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the Final Environmental Impact Statement (FEIS) and supplements as modified by staff's testimony to the Atomic Safety and Licensing Board, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or b) a significant change in effluents or power level; or c) a matter not previously reviewed and evaluated in the documents specified in a) of this section, which may have a significant adverse environmental impact.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable nonradiological environmental effects are confined to the onsite areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question or constitutes a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1, the licensee shall provide prior written notification to the NRC.

The licensee shall maintain records of changes in construction activities, changes in facility design or operation, and of tests and experiments carried out pursuant to this section. These records shall include a written evaluation which provides bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question nor constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1. The licensee shall include as part of their Annual Environmental Operating Report (per EPP Section 5.4.1) brief descriptions, analyses, interpretations, and evaluations of such changes, tests, and experiments.

3.5 Changes Required for Compliance with Other Environmental Law

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, or local environmental statutes, regulations, permits, or orders are not subject to the requirements of EPP Section 3.4.

4. Environmental Conditions

4.1 Unusual or Important Environmental Events

The licensee shall evaluate and report to the NRC Operations Center within 24 hours in accordance with 10 CFR 50.72(b)(2)(vi) (followed by a written report in accordance with EPP Section 5.4) any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to construction activities or plant operation under this license. The following are examples of unusual or important environmental events: excessive bird impaction events, onsite plant or animal disease outbreaks, mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973, fish kills, unusual increase in nuisance organisms or conditions, and unanticipated or emergency discharge of waste water or chemical substances.

Routine monitoring programs are not required to implement this condition.

5. Administrative Procedures

5.1 Review and Audit

The licensee shall provide for review and audit of compliance with the EPP. The audits shall be conducted independently and shall not be conducted by the individual or groups responsible for performing the specific activity. A description of the organization structure used to achieve the independent review and audit function and results of the audit activities shall be maintained and made available for inspection.

5.2 Records Retention

The licensee shall make and retain records associated with this EPP in a manner convenient for review and inspection and shall make them available to the NRC on request.

The licensee shall retain records of construction and operation activities determined to potentially affect the continued protection of the environment until the date of termination of the license. Records of modifications to station structures, systems and components determined to potentially affect the continued protection of the environment shall be retained for the life of the plant. All other records, data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Requests for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revisions to the EPP.

5.4 Reporting Requirements

5.4.1 Routine Reports

An Annual Environmental Operating Report describing implementation of this EPP for the previous year shall be submitted to the NRC prior to May 1 of each year. The period for the first report shall begin with the date of issuance of the Combined License, and the initial report shall be submitted prior to May 1 of the year following issuance of the Combined License. At the discretion of the licensee, the Annual Environmental Operating Report for Unit 3 may be combined with the Annual Operating Report submitted for Units 1 & 2.

The report shall include summaries and analyses of the results of the environmental protection activities required by EPP for the report period, including a comparison with related preoperational studies, operational controls (as appropriate), and previous nonradiological environmental monitoring reports, and an assessment of the observed impacts of the plant operation on the environment. If unexpected harmful effects or evidence of trends toward irreversible damage to the environment are observed, the licensee shall provide a detailed analysis of the data and a proposed course of mitigating action.

The Annual Environmental Operating Report shall also include:

(a) A list of EPP noncompliances and the corrective actions taken to remedy them

(b) A list of changes in station design or operation, tests, and experiments made in accordance with EPP Section 3.4 which involved a potentially significant unreviewed environmental issue

(c) A list of nonroutine reports submitted in accordance with EPP Section 5.4.2

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing results shall be submitted as soon as possible in a supplementary report.

5.4.2 Non-Routine Reports

A written report shall be submitted to the NRC within 60 days of occurrence of a nonroutine event that has a significant unanalyzed impact on the environment. The report shall: a) describe, analyze, and evaluate the event, including extent and magnitude of the impact, and plant operating characteristics; b) describe the probable cause of the event; c) indicate the action taken to correct the reported event; d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and e) indicate the agencies notified and their preliminary responses.

Events reportable under this section which also require reports to other Federal, State, or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such report at the same time it is submitted to the other agency.

References

1. U.S. Nuclear Regulatory Commission, “Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna ESP Site,” NUREG-1811, December 2006.
2. U.S. Nuclear Regulatory Commission, “Supplemental Environmental Impact Statement for the Combined License (COL) for North Anna Power Station Unit 3, “NUREG-1917, Draft Report for Comment, December 2008.
3. Dominion Nuclear North Anna, LLC, “North Anna Early Site Permit Application, Part 3 – Environmental Report,” Revision 9, September 2006.
4. Dominion Virginia Power, “North Anna 3 Combined License Application, Part 3 – Environmental Report,” Revision 6, July 2013.

Table 1. Mitigating Actions for Construction Activities

1. Mitigating Actions Identified in ESP-ER Section 4.6

ESP-ER Section 4.1.1

- Conduct ground disturbing activities in accordance with regulatory and permit requirements.
- Use adequate erosion controls and stabilization measures to reduce impacts to the extent practicable.
- Reduce potential impacts to wetlands and intermittent streams on the NAPS site through avoidance and compliance with applicable permitting requirements.

ESP-ER Section 4.1.3

- Conduct sub-surface testing prior to initiating ground disturbing activities to identify buried historic or archaeological resources.
- Take appropriate actions (e.g., stop work) following discovery of potential historic or archaeological resources.
- Use existing Virginia Power procedures that require contacting the appropriate regulatory agencies following a discovery of potential historic or archaeological resources.

ESP-ER Section 4.2.1

- Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to impede turbid water from migrating into the lake.
- Perform activities under applicable regulations and permit requirements with regard to seasonal restrictions for in-water work, installation of appropriate erosion control measures, drainage controls to convey stream flow, and construction storm water management.
- Use Best Management Practices (BMP) described in the Virginia Erosion and Sediment Control Handbook to control erosion and maintain the sediment load from the construction zone as low as practicable.
- Use wells unaffected by dewatering activities to maintain needed capacity for the NAPS site. Not all wells are expected to be affected by dewatering activities.

ESP-ER Section 4.2.2

- Develop and implement a construction Stormwater Pollution Prevention Plan (SWPPP) and spill response plan during construction at the NAPS site.
- Implement an Erosion and Sediment Control Plan that describes use of approved/recognized Best Management Practices (BMP).
- Limit dewatering activities to only those necessary for construction.
- Use offsite sources of potable water, if necessary, to temporarily supplement onsite water resources.

Table 1. Mitigating Actions for Construction Activities

ESP-ER Section 4.3.2

- Develop and implement a construction Stormwater Pollution Prevention Plan (SWPPP) and spill response plan during construction in the transmission corridor.
- Implement an Erosion and Sediment Control Plan that describes use of approved/recognized BMPs.
- Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to impede turbid water from migrating into the lake.
- Adhere to seasonal restrictions on in-water construction activities. Following temporary construction disturbance, intake channel cove will likely be re-colonized by benthic organisms and fish.

ESP-ER Section 4.4.1

- Train and appropriately protect NAPS site and temporary construction personnel (i.e., those most directly and frequently affected by construction noise, dust and gaseous emissions) to reduce the risk of potential harmful exposures from noise, dust, and gaseous emissions.
- Provide onsite services for emergency first aid care and conduct regular health and safety monitoring for affected personnel on site.
- Make public announcements and/or notifications prior to undertaking atypical or noisy construction activities.
- Use normal dust control measures (e.g., watering, stabilizing disturbed areas, covering truck loads).
- Manage concerns from adjacent residents, business owners, or landowners, on a case-by-case basis through a Dominion prepared concern resolution process.
- Post signs at or near construction site entrances and exits to make the public aware of potentially high construction traffic areas.
- Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to impede turbid water from migrating into the lake.

Table 1. Mitigating Actions for Construction Activities

ESP-ER Section 4.4.2

- Develop a construction traffic management plan prior to construction to address potential impacts on local roadways.
- Encourage the use of shared (e.g., carpooling) and multi-person transport (e.g., buses) of construction personnel to the ESP site.
- Coordinate schedules during workforce shift changes to limit impacts on local roads.
- Schedule delivery of larger pieces of equipment or structures on off-peak traffic hours (e.g., at night) or through other transportation modes (e.g., rail).
- Consider/coordinate, if necessary, with local planning authorities the upgrading of local roads, intersections, and signals to handle increased traffic loads.

Table 1. Mitigating Actions for Construction Activities

2. Mitigating Actions Identified in FEIS Section 4.10
• Incorporation of environmental requirements into construction contracts (ESP-ER Section 4.6).
• Avoid watercourses and wetlands to the extent practical during any construction (ESP-ER Sections 4.1.1.6.2, and 4.3.1.2).
• Develop a dust control plan to mitigate the impacts of emissions from construction activities (ESP-ER Section 4.4.1.4).
• Develop a construction traffic management plan to include several traffic mitigating measures (ESP-ER Section 4.4.2.2.1).
• Mitigate potential impacts for materials delivery. Methods include: 1) avoiding routes that could adversely affect sensitive areas (e.g., housing, hospitals, schools, retirement communities, businesses) to the extent possible and 2) restricting delivery times activities to daylight hours (ESP-ER Section 4.4.1.1.3).
• Repair damage to public roads, markings, or signs caused by construction activities (ESP-ER Section 4.4.1.1.3).
• Build and maintain new access road on the NAPS site to support construction activities (by Virginia Power personnel as needed) (ESP-ER Section 4.4.1.1.3).
• Maintain emissions from heavy construction equipment as low as reasonably practicable by scheduled equipment maintenance procedures (ESP-ER Section 4.3.1.2).
• Implement a Spill Prevention Control and Countermeasure Plan (ESP-ER Section 4.3.2).
• Manage nuisances and concerns from adjacent residents, business owners, or landowners on a case-by-case basis through a Dominion prepared concern resolution process (ESP-ER Section 4.4.1).
• Coordinate with the VDHR regarding the potential presence of historic and cultural resources within planned disturbed areas and notify VDHR in the event of any unanticipated discovery (ESP-ER Section 4.1.3).

Table 1. Mitigating Actions for Construction Activities

3. Mitigating Actions Identified in COL-ER Section 4.6

- Upon completion of the transports, temporary structures will be removed, interferences will be reinstalled, and disturbed areas will be restored. (Section 4.1.1)
- The new transmission line will be located in an existing corridor and constructed under practices and procedures applicable to the existing transmission lines (Sections 4.1.2, 4.2.1.1 and 4.3.1.1).
- Land clearing necessary to accommodate the new transmission tower foundations will be controlled by existing transmission line procedures, good construction practices, and established best management practices (Section 4.3.1.1), as well as all applicable regulations.
- Clearing methods for small trees, bushes and vegetation will be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water will be hand-cleared and material approximately three inches in diameter and above will be removed from the buffer, leaving material less than three inches undisturbed (Sections 4.1.2, 4.2.1.1, and 4.3.1.1).
- Once all the construction of transmission lines has been completed, Dominion will restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property (Sections 4.1.2 and 4.3.1.1).
- Appropriate actions (e.g., stop work) will be taken following discovery of potential historic or archaeological resources (Sections 4.1.2 and 4.1.3).
- While the goal is zero impacts to historic properties and cultural resources located adjacent to the proposed large component transport route, appropriate actions for potential impacts include rehabilitation of land, removal of debris, and restoration of damaged property (Section 4.1.3).
- Potential impacts to streams and creeks will be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks will be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials will be removed from the temporary crossing at the completion of the project (Sections 4.2.1.1 and 4.3.1.1).

Table 1. Mitigating Actions for Construction Activities

- Soil disturbances will be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies will be implemented to reduce runoff and erosion. These measures will be left in place, until stabilization of the area is achieved. Work sites will be stabilized prior to moving to the next area (Sections 4.2.1.1, 4.3.1.1, and 4.3.1.4).
- To the extent practicable, construction will avoid alterations to shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) will be consulted, and permits and approvals will be obtained as necessary (Sections 4.2.1.1 and 4.3.2).
- Dust suppression techniques will be utilized and equipment maintenance employed to reduce airborne emissions (Section 4.3.1.1).
- For wetlands along the proposed large component transportation route, temporary erosion and sedimentation controls will be maintained until permanent stabilization is achieved, debris is removed, and disturbed lands will be rehabilitated (Section 4.3.1.4).
- As a safety precaution, during installation of the transmission lines, access to the area will be temporarily restricted from recreational use (Section 4.4).
- To help avoid impacts to the archaeological resource along the transmission corridor, the identified archaeological site will be marked and/or flagged prior to and during construction of the new transmission line (Section 4.1.3).
- Impacts to wetlands within the additional property may be addressed through preservation of other onsite streams or through purchasing offset credits from an approved mitigation bank (Appendix 4A).
- The additional property area will be stabilized and structures will be removed upon completion of the construction of Unit 3 (Appendix 4A).

4. Mitigating Actions Identified in SEIS Section 4.10

- The new transmission lines would be located in an existing transmission line right-of-way and constructed under current practices and applicable procedures.
- Land-clearing activities to accommodate construction of the new transmission tower foundations would be controlled by existing Dominion transmission line procedures, good construction practices, established BMPs, and applicable regulations.

Table 1. Mitigating Actions for Construction Activities

- Once construction of the transmission lines has been completed, Dominion would restore disturbed areas by appropriate means, including restoring damaged property to its original condition to the satisfaction of the property owner.
- As a safety precaution, during the construction of the transmission lines, access to the transmission line right-of-way will be restricted.
- Clearing methods will be conducted in a manner to protect natural resources and control erosion and siltation of streams. Special procedures would be used for clearing trees and brush within 30 m (100 ft) of a stream or ditch with running water.
- Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings pursuant to standards and specifications by the Commonwealth of Virginia. Materials used for temporary crossings of streams and creeks would be removed and the landscape restored upon completion of the construction activities.
- Soil disturbances would be avoided or reduced to the extent practicable within 30 m (100 ft) of streams and ditches with running water. Erosion and sedimentation control measures would be implemented to reduce runoff and erosion.
- To the extent practicable, construction would avoid alterations to shoreline and wetland areas. If wetland areas will be impacted, appropriate Commonwealth and Federal agencies will be contacted and necessary permits and approvals will be obtained prior to construction activities that would impact the wetland areas.
- Dust suppression techniques would be utilized along with good equipment maintenance practices to reduce airborne emissions from construction-related activities.
- The discovery of potential historic or cultural resources will result in a stop work and appropriate procedures will be followed to notify the Virginia Department of Historic Resources.

Table 2. Mitigating Actions for Operation

1. Mitigating Actions Identified in ESP-ER Section 5.10

ESP-ER Section 5.1.1

- Water discharges from operation of the new unit will be governed by VPDES permit requirements.
- Potential increases in traffic will be mitigated through traffic management.

ESP-ER Section 5.2.1

- Practices to minimize the hydrologic alterations may be implemented.
- During periods of extended drought, dry cooling towers will be put into service to dissipate a portion of waste heat from Unit 3 to minimize the make-up water requirements.

ESP-ER Section 5.2.2

- During periods of extended drought, dry cooling towers will be put into service to dissipate a portion of waste heat from Unit 3 to minimize the make-up water requirements.

ESP-ER Section 5.3.1.1

- Stabilizing the banks of the channel to the screen house and pump house will be considered.

ESP-ER Section 5.3.1.2

- The intake structure for Unit 3 will meet such requirements as the VDEQ may impose under Section 316(b) of the Clean Water Act and the implementing regulations, as applicable.
- A fish return system based on the latest technology available during detailed engineering will be considered for incorporation into the intake system.

ESP-ER Section 5.3.2.2

- Cooling water discharges to the North Anna Reservoir will be governed by VPDES water quality standards and permitted discharge limits.

ESP-ER Section 5.4.1

- Sources of radiation at the new units will be contained similar to the existing units.

Table 2. Mitigating Actions for Operation

ESP-ER Section 5.5.1

- Water availability issues regarding the North Anna River are addressed via regulated releases from the North Anna Dam.
- Comply with applicable VPDES water quality standards for any discharge from Dike 3.
- Prepare and implement a new operational Stormwater Pollution Prevention Plan to avoid and/or minimize releases of contaminated stormwater.
- Use approved transporters and offsite landfills for disposal of solid waste. Continue existing units' program for reuse and recycling of nonradwastes.
- Operate any new minor air emission sources in accordance with applicable regulations and permits.
- Modify (if necessary) existing sanitary waste treatment systems to accommodate increased volume.

ESP-ER Section 5.5.2

- Limit need to manage and dispose of mixed waste through: 1) source reduction; 2) recycling options; 3) treatment.
- Develop a Waste Minimization Program, to address mixed waste inventory management; equipment maintenance; recycling and reuse; segregation; treatment (decay in storage); work planning; waste tracking; and awareness training.
- Implement a program to manage wastes stored onsite in compliance with applicable EPA and NRC regulatory requirements.
- Implement spill prevention and response plans and procedures to address hazards associated with managing mixed wastes. Include in plans and procedures measures for response personnel training and protective equipment.

Table 2. Mitigating Actions for Operation

ESP-ER Section 5.8.1

- Comply with applicable VDEQ permit limits and regulations when installing and operating air emission sources.
- Perform noise study as part of final design for dry cooling towers.
- Perform visual impact study for new structures on site, including dry and wet cooling towers, as part of final design.

ESP-ER Section 5.8.2

- Perform noise study as part of final design for dry and wet cooling towers.
- Perform visual impact study for new structures on site, including dry and wet cooling towers, as part of final design.

ESP-ER Section 5.9

- The significance of the impacts is unknown because the decommissioning methods have not been chosen. No mitigation measures or controls are proposed at this time.

2. Mitigating Actions Identified in FEIS Section 5.11

- Current transmission line maintenance practices will continue if two new units were built at the ESP site (ESP-ER Section 5.6.1.1).
- A system study modeling the transmission lines with new units' contribution will be conducted (ESP-ER Section 5.1.2).
- Take reasonable steps to identify locations of rare or sensitive plant species within transmission line corridors so modified treatment practices can be used in these areas to avoid adverse impacts (ESP-ER Section 5.6.1.1).
- Demonstrate that the fogging and salt deposition analysis of the cooling system remains bounding (May 24, 2006, response to RAI).
- The intake structure for the proposed new units at the ESP site will meet Section 316(b) of the Clean Water Act and the implementing regulations, as applicable (ESP-ER Section 5.3.1.2).
- Vegetative shielding will block a clear view of the new units from most nearby residences (ESP-ER Section 5.8.1.5, ESP-ER Table 5.10-1).
- Noise levels will be controlled in accordance with applicable local county regulations (ESP-ER Section 5.3.1.2).
- Although the operation of the new units are not expected to require changes in land use (ESP-ER Section 5.1), any ground-disturbing activities necessary for operations will be conducted in coordination with the VDHR and professional archaeological practices consistent with the process established for construction activities (ESP-ER Section 4.1.3).

Table 2. Mitigating Actions for Operation

3. Mitigating Actions Identified in COLA ER Section 5.10

- Non radioactive effluents, including sanitary waste and blowdown from Unit 3 cooling towers, will be controlled by the limits established in VPDES permit (Sections 5.2.2 and 5.5.1).
- The new and separate Unit 3 sanitary waste treatment systems will be governed by applicable regulations and permits (Section 5.5.1).
- Operation of a dechlorination system to neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir (Section 5.2.2).
- Increase the normal pool level of Lake Anna (North Anna Reservoir) by 3 inches from Elevation 250.0 ft msl to 250.25 ft msl to reduce the potential frequency of occurrence and duration of low flow conditions, and to reduce impacts on the ecology, wetlands, and recreation in Lake Anna and downstream (Section 5.10.1).
- Continue collaboration with Virginia resource agencies to address long-term enhancements within the watershed (Section 5.10.1).

4. Mitigating Actions Identified in SEIS Section 5.12

- Non-radioactive effluents, including sanitary waste and blowdown from the proposed Unit 3 cooling towers, will be controlled by limits established in the VPDES permit.
- The new and separate Unit 3 sanitary waste treatment systems will be governed by applicable regulations and permits.
- Operate a dechlorination system to neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir.

Chapter 2 Environmental Description

2.1 Site Location

The information for this section is provided in ESP-ER Section 2.1 and in FEIS Section 2.1. Figure 1.1-1 shows the layout of Unit 3 within the ESP site.

No new and significant information has been identified for this section.

2.2 Land

The information for this section is provided in ESP-ER Section 2.2 and in FEIS Section 2.2. Supplemental information is provided below.

2.2.1 The Site and Vicinity

Dominion owns additional property contiguous with the NAPS site. The additional property will provide alternative space for Unit 3 construction-related activities and facilities such as laydown areas, spoils storage, and access roads, but will not be part of the NAPS site. Further information is provided in Appendix 4A.

The additional property area will be stabilized and structures will be removed upon completion of the construction of Unit 3. The additional property will not become part of the North Anna Power Station.

2.2.2 Transmission Line Rights-of-Way and Offsite Areas

Based on an initial evaluation, the ESP-ER indicated that the existing transmission lines were expected to have sufficient capacity to carry the output of the new units at NAPS. However, a commitment was made to perform a load flow study to confirm that conclusion. In June 2007, PJM completed an impact study to determine the required system reinforcements associated with a new unit at North Anna. The study was updated in 2013 (Reference). Based on the results of this study, a new 15-mile long 500 kV line from the North Anna Substation to the Ladysmith Switching Substation will be installed on new transmission towers, within the existing transmission corridor. The location of this corridor is identified as “Line 575" on ESP-ER Figure 2.2-4, beginning at NAPS and heading east. Further information is provided in Section 3.7.

Additional property contiguous with the NAPS site will be utilized for Unit 3 project construction support. Additional information is provided in Appendix 4A.

2.2.3 The Region

No new and significant information has been identified for this section.

Section 2.2 Reference

PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

2.3 Water

The information for this section is provided in ESP-ER Section 2.3 and in FEIS Section 2.6. Supplemental information is provided below.

2.3.1 Hydrology

Based upon a field analysis (Reference 3) in accordance with the "Corps of Engineers Wetlands Delineation Manual", there were 31 wetlands and 26 waterways scattered along a proposed large component transport route.

Information on the hydrology of the additional property acquired for construction support is provided in Appendix 4A.

2.3.2 Water Use

No new and significant information has been identified for this section.

2.3.3 Water Quality

2.3.3.1 Surface Water

FEIS Section 5.3.3 identified the need to provide the chemical constituents of effluents in waste streams. This section provides information on surface water quality that is used (in conjunction with information in Section 3.3 concerning the chemical additives used in plant water systems) to determine the expected plant waste stream effluent discussed in Section 3.6.

Table 2.3-1 contains surface water quality data collected in the vicinity of the intake since submittal of the ESP-ER. The table provides the maximum value reported for each constituent. The parameters for which the samples were collected included the "126 Priority Pollutants" (Reference 1) as well as water temperature, suspended solids, total dissolved solids, hardness, turbidity, color, odor, conductivity, biological oxygen demand, chemical oxygen demand, phosphorus forms, nitrogen forms, alkalinity, chlorides, sulfate, sodium, potassium, calcium, magnesium, heavy metals, and pH. This surface water quality data is used in Section 3.6 in the discussion of the nonradioactive liquid wastes. Environmental impacts on surface water quality from station operation are discussed in Section 5.2.

2.3.3.2 Groundwater Aquifers

No new and significant information has been identified for this section.

Section 2.3 References

1. U.S. Environmental Protection Agency, "EPA Steam Electric Generating Point Source Category, 126 Priority Pollutants," 40 CFR 423, Appendix A.

2. Commonwealth of Virginia, State Water Control Board, "Virginia Water Quality Standards," 9 VAC 25-260 (et seq.), August 14, 2007.

3. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation Report for the Proposed Unit 3 Heavy Haul Route," June 2009.

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
011	1,1,1-Trichloroethane	0.00	N/A	3.80E-03	4 & 5
015	1,1,2,2-Tetrachloroethane	0.00	1.10E-01	6.90E-03	4
014	1,1,2-Trichloroethane	0.00	4.20E-01	5.00E-03	4
013	1,1-Dichloroethane	0.00	N/A	4.70E-03	4 & 5
029	1,1-Dichloroethylene	0.00	17.00	2.80E-03	4
008	1,2,4-Trichlorobenzene	0.00	9.40E-01	7.90E-03	4
	1,2-Dichlorobenzene	0.00	17.00	4.00E-03	4
010	1,2-Dichloroethane	0.00	9.90E-01	2.80E-03	4
032	1,2-Dichloropropane	0.00	3.90E-01	6.00E-03	4
037	1,2-Diphenylhydrazine	0.00	5.40E-03	8.80E-03	4
030	1,2-Trans-dichloroethylene	0.00	140.00	1.60E-03	4
	1,3-Dichlorobenzene	0.00	2.60	3.10E-03	4
	1,3-Dichloropropene	0.00	1.70	5.9E-03	4
	1,4 Dichlorobenzene	0.00	2.60	4.4E-03	4
	2 Methyl-4,6, Dinitrophenol	0.00	7.70E-01	2.58E-04	4
129	2,3,7,8-TCDD	0.00	N/A	9.30E-09	4 & 8
021	2,4,6-Trichlorophenol	0.00	6.50E-02	5.54E-04	4
031	2,4-Dichlorophenol	0.00	7.90E-01	4.24E-04	4
034	2,4-Dimethylphenol	0.00	2.30	3.19E-04	4
059	2,4-Dinitrophenol	0.00	14.00	3.54E-04	4
035	2,4-Dinitrotoluene	0.00	9.10E-02	5.70E-03	4
036	2,6-Dinitrotoluene	0.00	N/A	3.40E-03	4 & 5
019	2-Chloroethylvinyl Ether	0.00	N/A	1.20E-03	4 & 5
020	2-Chloronaphthalene	0.00	4.30	4.60E-03	4
024	2-Chlorophenol	0.00	4.00E-01	3.51E-04	4
057	2-Nitrophenol	0.00	N/A	4.75E-04	5
028	3,3'-Dichlrobenzidine	0.00	7.70E-04	1.65E-02	4
094	4,4-DDD	0.00	8.40E-06	2.1E-05	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
093	4,4-DDE	0.00	5.90E-06	1.7E-05	4
092	4,4-DDT	0.00	5.90E-06	1.7E-05	4
041	4-Bromophenyl-phenylether	3.00E-03	N/A	3.00E-03	5
040	4-Chlorophenyl-phenylether	0.00	N/A	4.20E-03	4 & 5
058	4-Nitrophenol	0.00	N/A	6.12E-04	4 & 5
001	Acenapthene	0.00	2.70	3.00E-03	4
077	Acenapthylene	0.00	N/A	3.50E-03	4 & 5
002	Acrolein	0.00	7.80E-01	1.0E-02	4
003	Acrylonitrile	0.00	6.60E-03	1.50E-03	4
089	Aldrin	0.00	1.40E-06	1.6E-05	4
102	Alpha BHC	0.00	1.30E-04	7.0E-06	4
095	Alpha-Endosulfan	0.00	2.40E-01	1.4E-05	4
	Ammonia as N	4.00E-02	1.20	1.0E-02	
078	Anthracene	0.00	110.00	1.90E-03	4
114	Antimony	0.00	4.30	1.00E-03	4
115	Arsenic	0.00	1.50E-01	3.00E-03	4
116	Asbestos (MF/L)	7.10E-01	N/A	1.80E-01	4 & 5
	Barium	3.20E-02	NAWQC	3.0E-03	6
004	Benzene	0.00	7.10E-01	4.40E-03	4
005	Benzidine	0.00	5.40E-06	6.30E-02	4
072	Benzo (a) Anthracene	0.00	4.90E-04	7.80E-03	4
073	Benzo (a) pyrene	0.00	4.90E-04	2.50E-03	4
074	Benzo (b) Fluoranthene	0.00	4.90E-04	4.80E-03	4
079	Benzo (g h i) perylene	0.00	N/A	4.10E-03	4 & 5
075	Benzo (k) Fluoranthene	0.00	4.90E-04	2.50E-03	4
117	Beryllium	0.00	N/A	2.00E-04	4 & 5
103	Beta BHC	0.00	4.60E-04	1.3E-05	4
096	Beta-Endosulfan	0.00	2.40E-01	1.7E-05	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
043	Bis (-2-Chloroethoxy) Methane	0.00	N/A	5.30E-03	4 & 5
018	Bis (-2-chloroethyl) Ether	0.00	1.40E-02	5.70E-03	4
	Bis (2-Chloroisopropyl) Ether	0.00	170.00	5.70E-03	4
066	Bis (2-ethylhexyl) Phthalate	0.00	5.90E-02	2.50E-03	4 & 5
	BOD	5.36	N/A	2.00	5
	Bromide	0.00	N/A	2.00E-01	4 & 5
047	Bromoform	0.00	3.60	4.70E-03	4
067	Butylbenzylphthalate	0.00	5.20	2.50E-03	4
118	Cadmium	0.00	3.80E-04	3.00E-04	4
	Calcium	3.68	N/A	9.0E-02	5
006	Carbon tetrachloride	0.00	4.40E-02	2.80E-03	4
091	Chlordane	0.00	2.20E-05	1.4E-05	4
	Chloride	5.07	230.00	5.0E-02	
007	Chlorobenzene	0.00	21.00	6.00E-03	4
051	Chlorodibromomethane	0.00	3.40E-01	3.10E-03	4
016	Chloroethane	0.00	N/A	1.10E-03	4 & 5
023	Chloroform	0.00	29.00	1.60E-03	4
	Chlorpyrifos	0.00	4.10E-05	1.38E-05	4
119	Chromium	0.00	N/A	1.00E-03	4, 5 & 7
	Chromium +6	0.00	1.10E-02	1.00E-02	4
076	Chrysene	0.00	4.90E-04	2.50E-03	4
	COD	15.64	N/A	5.0	5
	Color (Chloroplatinate Units)	20.00	N/A	N/A	5
	Conductivity (µmhos/cm)	70.00	N/A	N/A	5
120	Copper	3.00E-03	2.70E-03	1.0E-03	
121	Cyanide as CN	0.00	220.00	1.00E-02	4
105	Delta BHC	0.00	N/A	1.5E-05	4 & 5
	Demeton	0.00	1.00E-04	5.206E-04	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
083	Dibenzo (a h) anthracene	0.00	4.90E-04	2.50E-03	4
048	Dichlorobromomethane	0.00	4.60E-01	2.20E-03	4
090	Dieldrin	0.00	1.40E-06	1.00E-05	4
070	Diethylphthalate	0.00	120.00	7.40E-03	4
071	Dimethyl Phthalate	0.00	2900.00	7.50E-03	4
	Di-n-Butylphthalate	0.00	12.00	6.40E-03	4
069	Di-n-octyl Phthalate	0.00	N/A	2.50E-03	4 & 5
097	Endosulfan sulfate	0.00	2.40E-01	9.0E-6	4
098	Endrin	0.00	8.10E-04	2.0E-05	4
099	Endrin aldehyde	0.00	8.10E-04	1.9E-05	4
038	Ethylbenzene	0.00	29.00	7.20E-03	4
039	Fluoranthene	0.00	3.70E-01	2.20E-03	4
080	Fluorene	0.00	14.00	2.20E-03	4
104	Gamma BHC (Lindane)	0.00	6.30E-04	1.1E-05	4
	Gross Alpha (pCi/L)	0.00	15.00	<1.62	4
	Gross Beta (pCi/L)	2.64	4 mrem/yr	N/A	
	Guthion	0.00	1.00E-05	3.577E-04	4
	Hardness (ppm as $CaCO_3$)	29.07	N/A	3.0	5
100	Heptachlor	0.00	2.10E-06	1.6E-05	4
101	Heptachlor epoxide	0.00	1.10E-06	1.2E-05	4
009	Hexachlorobenzene	0.00	7.70E-06	3.10E-03	4
052	Hexachlorobutadiene	0.00	5.00E-01	1.80E-03	4
053	Hexachlorocyclopentadiene	0.00	17.00	1.00E-02	4
012	Hexachloroethane	0.00	8.90E-02	2.40E-03	4
	Hydrogen Sulfide	0.00	2.00E-03	5.00E-02	4
083	Indeno (1 2 3-CD) pyrene	0.00	4.90E-04	3.70E-03	4
054	Isophorone	0.00	26.00	5.10E-03	4
122	Lead	0.00	2.30E-03	1.00E-03	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
	Magnesium	2.63	N/A	1.0E-02	5
	Malathion	0.00	1.00E-04	1.227E-04	4
	M-Alkalinity (ppm as $CaCO_3$)	23.12	N/A	N/A	5
123	Mercury	1.01E-06	5.10E-05	2.0E-04	
	Methoxychlor	0.00	3.00E-05	1.7E-05	4
046	Methyl Bromide	0.00	4.00	1.40E-03	4
045	Methyl Chloride	0.00	N/A	1.10E-03	4 & 5
044	Methylene Chloride	0.00	16.00	2.80E-03	4
	Molybdenum	1.90E-02	N/A	1.0E-03	5
055	Naphthalene	0.00	N/A	3.80E-03	4 & 5
124	Nickel	0.00	4.60	5.00E-03	4
	Nitrate as N	1.70E-01	NAWQC	1.0E-02	6
	Nitrite as N	0.00	N/A	1.00E-02	4 & 5
056	Nitrobenzene	0.00	1.90	4.20E-03	4
061	N-Nitrosodimethylamine	0.00	8.10E-02	6.20E-03	4
063	N-nitroso-Di-n-propylamine	0.00	1.40E-02	3.60E-03	4
062	N-nitrosodiphenylamine	0.00	1.60E-01	2.70E-03	4
	Odor	Not reported	N/A	N/A	5
	Parathion	0.00	1.30E-05	1.21E-04	4
112	PCB 1016	0.00	1.40E-05	5.00E-02	4
108	PCB 1221	0.00	1.40E-05	3.00E-02	4
109	PCB 1232	0.00	1.40E-05	5.00E-02	4
106	PCB 1242	0.00	1.40E-05	5.00E-02	4
110	PCB 1248	0.00	1.40E-05	5.00E-02	4
107	PCB 1254	0.00	1.40E-05	3.60E-02	4
111	PCB 1260	0.00	1.40E-05	5.00E-02	4
064	Pentachlorophenol	0.00	8.20E-02	6.85E-04	4
	pH (standard units)	7.50	N/A	N/A	5

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
081	Phenanthrene	0.00	N/A	5.40E-03	4 & 5
065	Phenol	0.00	4600.00	4.8E-04	4
	Phosphate as P	Not reported	N/A	1.0E-02	5
	Phosphorous as P	1.90E-01	N/A	1.0E-02	5
	Potassium	2.86	N/A	1.0E-02	5
084	Pyrene	0.00	11.00	3.80E-03	4
125	Selenium	0.00	11.00	3.00E-03	4
126	Silver	0.00	3.20E-04	1.00E-04	4
	Sodium	4.00	N/A	1.0E-01	5
	Strontium (pCi/L)	0.00	8.00	N/A	
	Sulfate	7.42	NAWQC	6.0E-02	6
	Sulfide	2.0E-02	N/A	1.00E-02	4 & 5
	TDS	71.5	NAWQC	10.0	6
	Temperature (°C)	29.9	N/A	N/A	5
085	Tetrachloroethylene	0.00	8.90E-02	4.10E-03	4
127	Thallium	2.0E-04	6.30E-03	2.00E-04	4
	Tin	0.00	N/A	5.00E-03	4 & 5
086	Toluene	0.00	200.00	6.00E-03	4
	Total Kjeldahl Nitrogen, as N	3.9E-01	N/A	1.0E-02	5
	Total PCBs	4.70E-08	1.70E-06	N/A	
	Total Residual Chlorine	0.00	1.10E-02	1.00E-01	4
113	Toxaphene	0.00	7.50E-06	5.7E-05	4
	Trans-1,2 Dichloroethylene	0.00	140.00	1.6E-03	4
	Trans-1,3-Dichloropropene	Not reported	1.70	9.0E-04	
	Tributyltin	6.30E-05	6.30E-05	3.0E-05	
087	Trichloroethylene	0.00	8.10E-01	1.90E-03	4
	Tritium (pCi/L)	7,460.00	20,000.00	N/A	
	TSS	4.8	N/A	1.0	5

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2, 3, and 9)*	Detection Limit (mg/L) *(Note 2)*	Notes
	Turbidity (NTU)	3.40	N/A	N/A	5
088	Vinyl Chloride	0.00	6.10E-02	1.80E-03	4
128	Zinc	1.30E-02	69.00	1.0E-02	

Notes to Table 2.3-1:

1. The Priority Pollutant Numbers are in accordance with 40 CFR 423, Appendix A, EPA Steam Electric Generating Point Source Category (Reference 1).
2. Each constituent's Reported Level, Water Quality Criteria, and Detection Limit are specified in milligrams of constituent as ion per liter of water, unless specified otherwise.
3. The Water Quality Criteria listed are the human health surface water criteria applicable to Units 1 and 2 VPDES Permit. When human health surface water criterion is not defined for a particular constituent, the aquatic life criterion is used.
4. Many of the constituents were reported below the detection limit. These constituents are listed with a "Reported Level" of "0.00".
5. A Water Quality Criteria specified as "N/A" indicates that Virginia does not have numeric water quality criteria for that constituent.
6. A Water Quality Criteria specified as "NAWQC" means that the only existing Virginia numeric criterion for that parameter is for the protection of Public Water Supplies. Lake Anna is not a designated Public Water Supply.
7. The Water Quality Criterion presented is for Trivalent Chromium, which was not directly measured.
8. The Units 1 and 2 VPDES Permit does not have numeric water quality criteria for this constituent.
9. The Water Quality Criteria are based on existing VPDES Permit Water Quality for Units 1 and 2. New state water criteria, based on Virginia Water Quality Standards Regulation (9 VAC 25-260), effective February 2010, will be incorporated into station permits, as necessary and applicable. Any additional sampling will be performed as required.

2.4 Ecology

The information for this section is provided in ESP-ER Section 2.4 and in FEIS Sections 2.2, 2.4, and 2.7. Supplemental information is provided below.

2.4.1 Terrestrial Ecology

As described in Section 3.7, the PJM System Impact Study (Reference 1) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new line will be installed on new transmission towers along the existing corridor between the North Anna Substation and the Ladysmith Switching Substation (NAPS-to-Ladysmith corridor). Information concerning terrestrial ecology in the NAPS transmission corridors is provided in ESP-ER Sections 2.2 and 2.4. Supplemental information regarding wetlands and water bodies in the NAPS-to-Ladysmith transmission corridor is provided in Section 2.4.1.8.

Additionally, there are wetlands along a proposed large component transport route, which are described in Section 2.4.1.8. Regional road improvements will be made to the transport route, as necessary, to facilitate the delivery of large components.

Information on the terrestrial ecology of the additional property acquired for construction support is provided in Appendix 4A.

2.4.1.1 Terrain

No new and significant information has been identified for this section.

2.4.1.2 Wildlife Species

An assessment for wildlife species in the additional property acquired for construction support is provided in Appendix 4A.

2.4.1.3 Common Bird Species

An assessment for bird species in the additional property acquired for construction support is provided in Appendix 4A.

2.4.1.4 Wading Birds and Waterfowl

No new and significant information has been identified for this section.

2.4.1.5 Critical Habitat

A habitat assessment for the additional property acquired for construction support is provided in Appendix 4A. A subsequent habitat survey was performed as described in Sections 2.4.1.6 and 2.4.1.7, and Appendix 4A.

2.4.1.6 Endangered Species

An assessment for rare, threatened and endangered species in the additional property acquired for construction support was conducted in May 2008 and is provided in Appendix 4A.

In September 2009 (Reference 4), the VDCR determined that the North Anna ESP site, transmission corridor and the additional property may support habitat appropriate for small whorled pogonia (*Isotria medeoloides*) and, therefore, recommended that a site inventory be conducted. The small whorled pogonia grows in a variety of woodland habitats in Virginia, but tends to favor mid-aged woodland habitats on gently north or northeast favoring slopes often within small draws. This plant is listed as federally-threatened by the USFWS and as state-endangered by the Virginia Department of Agriculture and Consumer Services (VDACS). In November 2009, a plant-specific habitat survey was performed on the North Anna ESP site, the additional property and in the Blantons Powerline Conservation Site (Conservation Site) (through which the NAPS-to-Ladysmith transmission corridor runs). The survey, which was conducted in accordance with habitat criteria specific to the species, identified the presence of potential small whorled pogonia habitat on the North Anna ESP site (Reference 5). Follow-up plant-specific identification surveys, conducted on the site and additional property during the 2010 and 2012 flowering seasons (Reference 11), determined that the small whorled pogonia was not present. Survey results were communicated to appropriate regulatory agencies (Reference 7). The Virginia Department of Conservation and Recreation (VDCR) reviewed the 2010 survey report and concurred with the methodology and findings (Reference 8).

Potential habitat for the small whorled pogonia was also identified in the Conservation Site (Reference 6), however, none was found in the transmission corridor itself due to the plant species preferred habitat of forested areas and the disturbed nature of this habitat. As described in Section 3.7, no expansion of the corridor is required to accommodate the proposed new line.

2.4.1.7 Rare Plant Species

According to the VDCR, the Conservation Site supports Epling's hedgenettle (*Stachys eplingii*) as a natural heritage resource of concern, and the VDCR recommends the avoidance of this species. The Epling's hedgenettle, while neither a federally- nor state-listed species, is considered rare by the Commonwealth of Virginia.

A plant-specific habitat survey (Reference 6) performed in November 2009 identified potential habitat for the Epling's hedgenettle in the Conservation Site. Follow-up plant-specific identification surveys, conducted during the 2010 and 2012 flowering seasons (Reference 9) (Reference 12), determined that the Epling's hedgenettle was present. Survey results were communicated to appropriate regulatory agencies (Reference 10).

2.4.1.8 Wetlands

The new 500 kV transmission line will be installed on new towers in the existing NAPS-to-Ladysmith corridor. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long. The NAPS-to-Ladysmith corridor crosses the following jurisdictional water bodies and wetlands, identified on the USGS Ladysmith (VA) Quadrangle (Reference 2):

- Lake Anna
- Five tributaries to Lake Anna
- Nine tributaries to Northeast Creek, which is a tributary of the North Anna River below the Lake Anna dam
- Five tributaries to the South River
- One tributary to the Motto River

The two largest areas of wetlands in the corridor are along Northeast Creek, approximately 3 miles north of the dam, and along a tributary of the South River, approximately 3 miles west of the Ladysmith Switching Substation.

There were 31 wetlands identified along a proposed large component transport route. Seven are in the areas expected to be impacted by construction. Two of these are potential tidal wetlands, including one area designated as shoreline. The other five are non-tidal wetlands (Reference 3).

Supplemental information on wetland impacts is provided in Section 5.10.1.5 that addresses specifically the lake mitigating actions resulting from the IFIM study.

Within the additional property, nine nontidal wetlands have been identified, as described in Appendix 4A.

2.4.1.9 Important Species

Additional surveys for important species are addressed in Sections 2.4.1.6 and 2.4.1.7.

2.4.1.10 Proposed Site

No new and significant information has been identified for this section.

2.4.2 Aquatic Ecology

No new and significant information has been identified for this section.

Section 2.4 References

1. PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

2. U.S. Geological Survey (USGS), "Ladysmith (VA) Quadrangle," UTM 18 274527E 4214449N.

3. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation Report for the Proposed Unit 3 Heavy Haul Route," June 2009.

4. Virginia Department of Conservation and Recreation, letter from Rene Hypes to Michael Sackschewky, Pacific Northwest National Laboratory, dated September 29, 2009.

5. Williamsburg Environmental Group Inc., "Habitat Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," November 2009.

6. Williamsburg Environmental Group Inc., "Habitat Survey for the Epling's Hedge-nettle (*Stachys eplingii*) and Small Whorled Pogonia (*Isotria medeoloides*) Blantons Powerline Conservation Site, Caroline County, Virginia," November 2009.

7. Dominion Resources Services, Inc., "Supplemental Coastal Zone Management Act Federal Consistency Certification," September 30, 2010.

8. Virginia Department of Environmental Quality, "Federal Consistency Certification for a Combined Construction and Operation License and U.S. Army Corps of Engineers Permit for the North Anna Power Station Unit 3, Virginia Power, DEQ-10-167F," May 16, 2011.

9. Williamsburg Environmental Group Inc., "Detailed Survey for the Epling's Hedge-nettle (*Stachys eplingii*) Blantons Powerline Conservation Site, Caroline County, Virginia," July 2010.

10. Dominion Resources Services, Inc., "Transmittal of Epling's Hedgenettle Survey Report Virginia Electric and Power Company (Dominion) North Anna Power Station - Proposed Unit 3 Louisa County, Virginia," March 7, 2011.

11. Williamsburg Environmental Group Inc., "Detailed Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," August 3, 2012.

12. Williamsburg Environmental Group Inc., "Detailed survey for the Epling's Hedge-nettle (*Stachys eplingii*) Blantons Powerline Conservation Site, Caroline County, Virginia," July 20, 2012.

2.5 Socioeconomics

The information for this section is provided in ESP-ER Section 2.5 and in FEIS Sections 2.8 and 2.9. Supplemental information concerning historic properties is provided in Sections 2.5.3.3 and 2.5.3.5.

2.5.1 Demography

No new and significant information has been identified for this section.

2.5.2 Community Characteristics

No new and significant information has been identified for this section.

2.5.3 Historic Properties

No new and significant information has been identified for this section.

2.5.3.1 Description of Historic Properties Near the NAPS Site

No new and significant information has been identified for this section.

2.5.3.2 Description of Historic Properties Within the NAPS Site

No new and significant information has been identified for this section.

2.5.3.3 Transmission Rights-of-Way

The Louis Berger Group, Inc. completed a cultural resource assessment (ESP-ER Section 2.5, Reference 21) of the NAPS site and a 1-mile radius surrounding the existing units (study area) during the Units 1 & 2 license renewal project time period. The assessment included the following activities:

- A background investigation of related information to compile known information about the NAPS study area; and
- The delineation of areas within the study area containing potential archaeological resources.

An additional archaeological survey was completed for the NAPS-to-Ladysmith corridor in 2009 (Reference 1). The survey was conducted in accordance with the National Historic Preservation Act of 1966, the Archaeological and Historic Preservation Act of 1974, Executive Order 11593, and Title 36 of the Code of Federal Regulations, Part 60-66 and 800 (as appropriate).

The objectives of the archaeological survey were: 1) to document previously recorded cultural resources within the area of potential effects, 2) to identify any previously unrecorded archaeological sites within the project corridor, and 3) to evaluate the possible eligibility of any such sites for inclusion in the National Register of Historic Places. The fieldwork portion of the survey included a pedestrian reconnaissance of the transmission line right-of-way augmented with subsurface testing at selected locations. Excluding the submerged portions of the project corridor, the total area surveyed for archaeological resources measures approximately 464 acres (188 hectares). The survey resulted in the identification of one site, the presumed remains of a mid-nineteenth-century structure, which has potential to yield significant archaeological information relative to the Domestic, and possibly the Agriculture/Subsistence themes during the Antebellum Period (1830–1860) through the Reconstruction and Growth (1865–1917) time periods in the Upper Coastal Plain region of Virginia. This site will be avoided during any future development or modification of the transmission line corridor. If avoidance of a cultural resources site is deemed impractical, consultation with VDHR will be re-initiated to determine other appropriate treatment measures.

The Louis Berger Group also completed a Phase I architectural study of the areas within a one-half mile radius of the NAPS-to-Ladysmith corridor (Reference 2). Following the *Guidelines for Assessing Impacts of Proposed Electric Transmission Lines and Associated Facilities on Historic Resources in the Commonwealth of Virginia* (Reference 3), the architectural area of potential effects for the 14.5-mile (23.3-kilometer) NAPS-to-Ladysmith 500 kV transmission line was defined to include any architectural resources approximately 50 years or older within 0.5-mile (0.8 kilometer) on either side of the existing corridor centerline, owing to a greater than 10 percent increase in tower height.

The objectives of the architectural survey were to: 1) review and update existing information on previously recorded architectural resources within the Area of Potential Effects; 2) identify and record, at a reconnaissance level, any previously unrecorded architectural resources within the area of potential effects; and 3) evaluate the eligibility of these resources for inclusion in the National Register of Historic Places. Thirty-six previously unrecorded architectural resources were surveyed within the area of potential effects, the majority of which were examples of common mid-nineteenth-century to mid-twentieth-century single dwellings and vernacular farm buildings. Berger recommends 35 of the 36 newly surveyed architectural resources and 14 of the 17 previously recorded architectural resources in the surveyed area as not eligible for inclusion in the National Register of Historic Places. Of the properties surveyed, one newly surveyed resource, a farm on Blantons Road, is recommended as eligible for inclusion in the National Register of Historic Places. Three of the 17 previously recorded resources within the area of potential effects could not be surveyed.

2.5.3.4 Native American Sites

No new and significant information has been identified for this section.

2.5.3.5 Large Component Transport Route

The proposed large component transport route begins in King William County at a historic ferry landing on the Mattaponi River near the town of Walkerton, and ends at NAPS. Historic site impacts could occur at the following locations: the ferry landing roll-off location, the North Anna River crossing, the Beaverdam Depot, and the I-95 crossing (Reference 4).

The historic ferry landing near Walkerton is planned as the beginning of the preferred large component transport route. It is adjacent to a multi-component prehistoric and historic archaeological site recorded in 1991. The area near the ferry landing, which is the preferred off-load location, was evaluated in 1993 and recommended eligible for inclusion in the National Register of Historic Places.

In June of 2011, an archaeological survey (Reference 5) of the route was completed: 1) to document previously recorded cultural resources within the area of potential effects; 2) to identify any previously unrecorded archaeological sites within the area of potential effects; and 3) to evaluate the potential eligibility of any such sites for listing in the National Register of Historic Places. The survey included both terrestrial and underwater investigations.

The terrestrial survey identified three artifact locations along the route, and relocated and expanded the boundaries of the previously recorded Walkerton Landing Site, also known as the Enfield Plantation. The Walkerton Landing Site has been determined to be eligible for listing in the National Register of Historic Places.

An underwater survey, consisting of side-scan sonar investigations, concluded that there were no submerged cultural features associated either with the Walkerton Ferry or a wharf at the Site. The VDHR reviewed the results of the terrestrial and underwater survey and found that the large component transport route would not adversely affect historic properties (Reference 6). Based upon these results, a Ground Disturbance Plan for the Site will be implemented to avoid and protect cultural resources.

The proposed North Anna River crossing occurs near identified historic sites. The proposed construction of a bridge may occur in a previously recorded archaeological site. Five additional archaeological sites and one architectural resource have been identified along the eastern bank of the North Anna River in the vicinity of the existing Route 30 bridges. Some of these historic properties have been evaluated for National Register eligibility. There could also be deeply-buried deposits along the western bank of the North Anna River.

The historic Beaverdam Depot in the town of Beaverdam, was built in 1866 and has been recommended as eligible for inclusion in the National Register of Historic Places.

The I-95 crossing is difficult to assess without detailed plans. Although the general area has been extensively altered by highway and railroad construction, the optional I-95 crossings are located within the North Anna Battlefield. This large battlefield spreads across northern Hanover and southern Caroline counties. Preliminary survey data indicates that this Civil War battlefield is likely eligible for inclusion in the National Register.

2.5.4 Environmental Justice

No new and significant information has been identified for this section.

Section 2.5 References

1. The Louis Berger Group, Inc., "Archaeological Survey as Part of a Cultural Resource Survey of the Proposed North Anna-Ladysmith 500 kV Transmission Line," June 2009.
2. The Louis Berger Group, Inc., "Architectural Survey of the Proposed North Anna-Ladysmith 500 kV Transmission Line," June 2009.
3. Guidelines for Assessing Impacts of Proposed Electric Transmission Lines and Associated Facilities on Historic Resources in the Commonwealth of Virginia, Virginia Department of Historic Resources, Richmond, VA, 2008.
4. The Louis Berger Group, Inc., "Cultural Resource Assessment of a Proposed Heavy Haul Route to the North Anna Power Station ESP Site," June 2009.
5. Dominion Energy, Inc., "Dominion Virginia Power, North Anna Power Station, Unit 3, Large Component Transport Route, VDHR File No.: 2000-1200," July 7, 2011.
6. Virginia Department of Historic Resources, "Terrestrial and Underwater Archaeological Survey of the Proposed Large Component Transport Route, King William, Hanover, and Louisa Counties, Virginia DHR File No. 2000-1210," July 29, 2011.

2.6 Geology

The information for this section is provided in ESP-ER Section 2.6 and in FEIS Section 2.4. Supplemental information concerning site geology is provided in Sections 2.6.2.2.1 and 2.6.4.2.1.

2.6.1 Geological Conditions

No new and significant information has been identified for this section.

2.6.2 Seismological Conditions

2.6.2.1 Tectonic Setting

No new and significant information has been identified for this section.

2.6.2.2 Seismic Sources

No new and significant information has been identified for this section.

2.6.2.2.1 Seismic Source Zones

The Central and Eastern United States Seismic Source Characterization (CEUS SSC) host seismotectonic source for the Unit 3 site is the Extended Continental Crust-Atlantic Margin Zone (ECC-AM), which includes the region characterized by the presence of extended continental crust developed during Mesozoic rifting along the Atlantic Ocean basin margin (Reference 1).

The 200-mile radius site region encompasses two areas of elevated seismic activity. These seismically active areas, which had previously been considered seismic source zones, consist of the Central Virginia Seismic Zone (CVSZ) and the Giles County Seismic Zone (References 2 and 3).

The August 23, 2011, moment magnitude (M) 5.8 Mineral, Virginia earthquake was the largest historical seismic event in the CVSZ, surpassing an earthquake that occurred in Goochland County, Virginia in 1875 that had an estimated magnitude of about M 4.8 based on felt reports and damage (Reference 4). The largest known earthquake to occur in the Giles County Seismic Zone was the May 31, 1897 M 5.9 Giles County event.

2.6.2.2.2 Tectonic Surfaces (Faults)

No new and significant information has been identified for this section.

2.6.3 Geotechnical Conditions

No new and significant information has been identified for this section.

2.6.4 Environmental Impact Evaluation

2.6.4.1 Geological Impacts

No new and significant information has been identified for this section.

2.6.4.2 Seismological Impacts

2.6.4.2.1 Ground Shaking

The CEUS SSC earthquake catalog was updated to include the last three years of seismicity data from 2009 through mid-December 2011, including the **M** 5.8 Mineral, Virginia earthquake. Including the update, the maximum magnitude distribution ranges from the lower bound of **M** 6.0 to the upper bound of **M** 8.1 with a mean of **M** 7.2 for the ECC-AM.

2.6.4.2.2 Surface Fault Rupture

No new and significant information has been identified for this section.

2.6.4.3 Geotechnical Impacts

No new and significant information has been identified for this section.

Section 2.6 References

1. U.S. NRC, U.S. DOE, and EPRI, NUREG-2115, "Central and Eastern United States Seismic Source Characterization for Nuclear Facilities," January 2012.

2. Bingham, E., "The Physiographic Provinces of Virginia," Virginia Geographer, Volume 23 (2), Fall-Winter 1991.

3. Rader, E.K., and N.H. Evans, editors. "Geologic Map of Virginia-Expanded Explanations," Virginia Division of Mineral Resources, 1993.

4. USGS, Website, Earthquake Hazards Program, Magnitude 5.8--Virginia, 2011 August 23, 17:51:04 UTC, available at http://earthquake.usgs.gov/earthquakes/recenteqsww/Quakes/se082311a.php, accessed on May 8, 2012.

2.7 Meteorology and Air Quality

The information for this section is provided in ESP-ER Section 2.7 and in FEIS Section 2.3. Supplemental information concerning atmospheric dispersion coefficients is provided in Sections 2.7.5 and 2.7.6.

2.7.1 General Climate

No new and significant information has been identified for this section.

2.7.2 Regional Air Quality

No new and significant information has been identified for this section.

2.7.3 Severe Weather

No new and significant information has been identified for this section.

2.7.4 Local Meteorology

No new and significant information has been identified for this section.

2.7.5 Short-Term Diffusion Estimates

For the short-term atmospheric dispersion coefficients (used in the evaluation of doses due to design basis accidents, in Section 7.1), the ESP values listed in FEIS Table 5-14 are used for this ER.

2.7.6 Long-Term (Routine) Diffusion Estimates

As a part of the preparation of this ER, the annual Radiological Environmental Monitoring Program was reviewed to determine if the distances to any of the nearest sensitive receptors, modeled for the ESP-ER have changed. The results are documented in Table 2.7-1 based on a field survey and plotting of receptor locations using Geographic Information System (GIS) technology. This process provided improved distance accuracy for these receptors. The results show the closest receptor to be a residence in the NW direction at a distance of 1.28 km (4207 feet). For the purposes of the atmospheric dispersion analysis and the subsequent dose evaluations, it was conservatively assumed that each sensitive receptor (meat animal, vegetable garden, residence) is at the distance to the closest receptor and that the closest receptor is the residence in the NW direction at the previously determined distance of 1.20 km (3930 ft). Therefore, one of each type of receptor was assumed to be at 1.20 km (3930 feet) in each compass direction. For releases originating from within the plant facility boundary (i.e., from the Reactor Building, Turbine Building, and Radwaste Building), the maximum annual average χ/Q value calculated for the nearest residence, vegetable garden, and meat animal, all assumed at 1.20 km (0.74 mi), is 4.2E-06 sec/m^3 in the ESE direction. The maximum D/Q for those receptors is 1.1E-08 m^{-2} in the NNE direction. In the evaluation performed for this ER, the maximum annual χ/Q (no decay, undepleted) at the EAB is 3.3E-06 sec/m^3, based on a distance of 1.42 km (0.88 mile) to the ESE of the facility boundary from ESP-ER Table 2.7-16 and a minimum Turbine Building cross-sectional area of 3098 m^2 (33,347 ft^2). The results are summarized in Table 2.7-2. This table presents the maximum calculated χ/Qs and D/Qs at sensitive receptors.

Long-term (annual average) χ/Q and D/Q estimates generated by the XOQDOQ model for the sensitive receptors and at distances between 0.25 mile to 50 miles, as well as for various segment boundaries, are also presented. Table 2.7-4 presents χ/Q and D/Q estimates at the specific points of interest.

Table 2.7-5 presents the no decay and undepleted χ/Q estimates at various downwind distances between 0.4 km (0.25 mi) and 80.5 km (50 mi). Table 2.7-6 presents the no decay and undepleted χ/Q estimates for various distance segments out to 80.5 km (50 mi).

Table 2.7-7 presents the 2.26 day decay (for short-lived noble gases) and undepleted χ/Q estimates at the same downwind distances. Table 2.7-8 presents the 2.26 day decay and undepleted χ/Q estimates for the same distance segments.

Table 2.7-9 presents the 8 day decay (for all iodines released to the atmosphere) and depleted χ/Q estimates at the same downwind distances. Table 2.7-10 presents the 8 day decay and depleted χ/Q estimates for the same distance segments.

Table 2.7-11 presents the D/Q estimates for the same downwind distances. Table 2.7-12 presents the D/Q estimates for the same distance segments.

The methodology used to determine the long-term dispersion and deposition coefficients (used in the evaluation of doses due to normal operating releases) remains the same as that described in ESP-ER Section 2.7.6.

The following input data and assumptions were used in the XOQDOQ modeling of routine releases from the vent stacks of the Reactor Building (RB-VS), Turbine Building (TB-VS), and Radwaste Building (RW-VS); and from the CIRC cooling tower:

- Meteorological Data: Three-year combined (1996–1998) onsite joint frequency distribution of wind speed, wind direction, and atmospheric stability.
- Type of Release: Mixed mode (RB-VS and TB-VS) and ground level (RW-VS and CIRC cooling tower).
- Wind Sensor Height: 10 m (33 ft).
- Vertical Temperature Difference from instruments at: 10 m (33 ft) - 48.4 m (158.9 ft).
- Number of Wind Speed Categories: 7.
- Release Height: 52.77 m (173.09 ft) for RB-VS, 71.3 m (234 ft) for TB-VS, 0.0 m (0.0 ft) for RW-VS, 0.0 m (0.0 ft) for CIRC cooling tower.
- Building Height: 46.1 m (151.2 ft) effective height of Turbine Building (TB) for RB-VS, TB-VS, and RW-VS releases, and 0.0 m (0.0 ft) for CIRC Cooling Tower.
- Minimum Turbine Building Cross-Sectional Area: 3098 m^2 (33,347 ft^2).
- Stack Average Velocity: 17.78 m/s (58.33 ft/s) for RB-VS and TB-VS.
- Stack Inside Diameter: 2.40 m (7.9 ft) for RB, 1.95 m (6.4 ft) for TB, 0.0 m (0.0 ft) for RW, 0.0 m (0.0 ft) for CIRC cooling tower.
- Distances from the release point to the nearest point on the site boundary: See Tables 2.7-1 and 2.7-4, which provide the same distances as ESP-ER Table 2.7-16.
- The distance for each sensitive receptor in each direction was assumed to occur at the distance for the nearest residence for releases from the RB, TB, and RW vent stacks.

For releases from the RB-VS, TB-VS, and RW-VS, χ/Q and D/Q calculations at the EAB were computed using distances from the plant facility boundary (FSAR Figure 2.0-205) to the EAB in each sector. For releases from the CIRC cooling tower, which lies outside the plant facility boundary, χ/Q and D/Q calculations at the EAB were computed using distances from the CIRC cooling tower to the EAB in each sector.

For the RB-VS, TB-VS, and RW-VS dispersion analyses, the Turbine Building was used to determine the minimum building cross-sectional area for evaluating building downwash effects. The height of this building is approximately 52 m (170.6 ft), and as the tallest building within the plant facility boundary, this building creates the largest wake. Because the Turbine Building is close enough to each of the three stacks, each will experience wake effects (dispersion) due to the

Turbine Building. Also, because the Turbine Building is taller than the other buildings within the plant facility boundary, the building-induced turbulence for the Turbine Building effectively envelops the wakes from the other lower height structures. Therefore, only the Turbine Building wake was considered and was based on the Turbine Building cross-sectional area. A width of 67.2 m (220.5 ft) at the base of the building, and a minimum building cross-sectional area of 3098 m^2 (33,347 ft^2) were used to determine χ/Q and D/Q estimates. This minimum Turbine Building area was divided by the width at the base to obtain the effective height, which accounts for the irregular shape of the top of the Turbine Building. An effective Turbine Building height of 46.1 m (151.2 ft) was used for modeling the releases from the RB-VS, TB-VS, and RW-VS. For Unit 3, the χ/Q and D/Q values were found to depend on building height but not cross-sectional area.

ESP-ER Tables 2.7-13 through 2.7-20 have been replaced in this ER by Tables 2.7-1 through 2.7-12.

No other new and significant information has been identified for this section.

Table 2.7-1 Source to Sensitive Receptor Distances

Type (Note 3)	Direction from Unit 3	Distance from Plant Facility Boundary (ft) *(Note 1)*	Distance from Plant Facility Boundary (miles/km) *(Note 1)*
Vegetation			
Veg	S	5605	1.06/1.71
Veg	SSW	22877	4.33/6.97
Veg	SW	17254	3.27/5.26
Veg	WSW	No Receptor	
Veg	W	14891	2.82/4.54
Veg	WNW	7608	1.44/2.32
Veg	NW	No Receptor	
Veg	NNW	11399	2.16/3.47
Veg	N	13672	2.59/4.17
Veg	NNE	17318	3.28/5.28
Veg	NE	5029	0.95/1.53
Veg	ENE	13272	2.51/4.05
Veg	E	8519	1.61/2.60
Veg	ESE	11826	2.24/3.60
Veg	SE	4658	0.88/1.42
Veg	SSE	4609	0.87/1.40
Meat Animal			
Meat	S	8712	1.65/2.66
Meat	SSW	9476	1.79/2.89
Meat	SW	6468	1.23/1.97
Meat	WSW	No Receptor	
Meat	W	20424	3.87/6.23
Meat	WNW	21339	4.04/6.50
Meat	NW	No Receptor	
Meat	NNW	No Receptor	
Meat	N	11441	2.17/3.49

Table 2.7-1 Source to Sensitive Receptor Distances *(continued)*

Type (Note 3)	Direction from Unit 3	Distance from Plant Facility Boundary (ft) *(Note 1)*	Distance from Plant Facility Boundary (miles/km) *(Note 1)*
Meat Animal (continued)			
Meat	NNE	7868	1.49/2.40
Meat	NE	7940	1.50/2.42
Meat	ENE	14428	2.73/4.40
Meat	E	19631	3.72/5.98
Meat	ESE	7058	1.34/2.15
Meat	SE	7711	1.46/2.35
Meat	SSE	10445	1.98/3.18
Resident			
Res	S	4339	0.82/1.32
Res	SSW	4575	0.87/1.39
Res	SW	6468	1.23/1.97
Res	WSW	6107	1.16/1.86
Res	W	5263	1.00/1.60
Res	WNW	5421	1.03/1.65
Res	NW	4207	0.80/1.28
Res	NNW	4587	0.87/1.40
Res	N	4846	0.92/1.48
Res	NNE	5695	1.08/1.74
Res	NE	5029	0.95/1.53
Res	ENE	8748	1.66/2.67
Res	E	7158	1.36/2.18
Res	ESE	7506	1.42/2.29
Res	SE	4830	0.91/1.47
Res	SSE	4394	0.83/1.34

Table 2.7-1 Source to Sensitive Receptor Distances *(continued)*

Type (Note 3)	Direction from Unit 3	Distance from Plant Facility Boundary (ft) *(Note 1)*	Distance from Plant Facility Boundary (miles/km) *(Note 1)*
Site Boundary (Exclusion Area Boundary)			
EAB	S	3274	0.62/1.00
EAB	SSW	3009	0.57/0.92
EAB	SW	2851	0.54/0.87
EAB	WSW	2903	0.55/0.88
EAB	W	2851	0.54/0.87
EAB	WNW	2956	0.56/0.90
EAB	NW	3274	0.62/1.00
EAB	NNW	3802	0.72/1.16
EAB	N	4593	0.87/1.40
EAB	NNE	4646	0.88/1.42
EAB	NE	4751	0.90/1.45
EAB	ENE	4806	0.91/1.46
EAB	E	4698	0.89/1.43
EAB	ESE	4646	0.88/1.42
EAB	SE	4383	0.83/1.34

Notes:
1. Distances are from the plant facility boundary. See FSAR Figure 2.0-205.
2. Not used.
3. No milk cows or goats within a 5-mile radius of NAPS.

Table 2.7-1 Source to Sensitive Receptor Distances *(continued)*

Type (Note 3)	Direction from Unit 3	Distance from Plant Facility Boundary (ft) *(Note 1)*	Distance from Plant Facility Boundary (miles/km) *(Note 1)*
Site Boundary (Exclusion Area Boundary)			

Notes:

1. Distances are from the plant facility boundary. See FSAR Figure 2.0-205.
2. Not used.
3. No milk cows or goats within a 5-mile radius of NAPS.

Table 2.7-2 XOQDOQ Predicted Maximum χ/Q and D/Q Values at Specific Points of Interest

Type of Location	Structure	Release Type	Direction from Site (True North)	Distance (miles)	χ/Q (No Decay, Undepleted)	χ/Q (2.26 Day Decay, Undepleted)	χ/Q (8 Day Decay, Depleted)	D/Q
Residence	RB	Mixed	NNE	0.74	6.8E-08	6.8E-08	6.6E-08	1.8E-09 [b]
EAB	RB	Mixed	NNE	0.88	7.1E-08	7.1E-08	6.9E-08	1.7E-09 [a]
Meat Animal	RB	Mixed	NNE	0.74	6.8E-08	6.8E-08	6.6E-08	1.8E-09 [b]
Veg. Garden	RB	Mixed	NNE	0.74	6.8E-08	6.8E-08	6.6E-08	1.8E-09 [b]
Residence	TB	Mixed	NNE	0.74	5.5E-08	5.5E-08	5.3E-08	1.8E-09
EAB	TB	Mixed	NNE	0.88	5.2E-08	5.2E-08	5.0E-08	1.6E-09 [c]
Meat Animal	TB	Mixed	NNE	0.74	5.5E-08	5.5E-08	5.3E-08	1.8E-09
Veg. Garden	TB	Mixed	NNE	0.74	5.5E-08	5.5E-08	5.3E-08	1.8E-09
Residence	RW	Ground	ESE	0.74	4.2E-06	4.2E-06	3.8E-06	1.1E-08 [e]
EAB	RW	Ground	ESE	0.88	3.3E-06	3.3E-06	2.9E-06	1.1E-08 [d]
Meat Animal	RW	Ground	ESE	0.74	4.2E-06	4.2E-06	3.8E-06	1.1E-08 [e]
Veg. Garden	RW	Ground	ESE	0.74	4.2E-06	4.2E-06	3.8E-06	1.1E-08 [e]
Residence	CIRC CT	Ground	ESE	0.74	6.3E-06	6.2E-06	5.6E-06	1.1E-08 [g]
EAB	CIRC CT	Ground	W	0.34	6.4E-06	6.4E-06	6.0E-06	2.1E-08 [f]
Meat Animal	CIRC CT	Ground	ESE	0.74	6.3E-06	6.2E-06	5.6E-06	1.1E-08 [g]
Veg. Garden	CIRC CT	Ground	ESE	0.74	6.3E-06	6.2E-06	5.6E-06	1.1E-08 [g]

Table 2.7-2 XOQDOQ Predicted Maximum χ/Q and D/Q Values at Specific Points of Interest

Notes:

χ/Q – sec/m^3

D/Q – 1/m^2

RB – Reactor Building
TB – Turbine Building
RW – Radwaste Building
CIRC CT – CIRC Cooling Tower

a - Direction South and South-Southeast at distances of 0.62 and 0.73 mi, respectively, for maximum D/Q for EAB.

b - Direction North-Northeast and Southeast at distances of 0.74 mi for maximum D/Q for Residence, Meat Animal and Veg. Garden.

c - Direction North-Northeast and South-Southeast at distances of 0.88 and 0.73 mi, respectively, for maximum D/Q for EAB.

d – Direction South at distance of 0.62 mi for maximum D/Q for EAB.

e - Direction North-Northeast at distance of 0.74 mi for maximum D/Q for Residence, Meat Animal and Veg. Garden.

f - Direction South at distance of 0.43 mi for maximum D/Q for EAB.

g - Direction North-Northeast at distance of 0.74 mi for maximum D/Q for Residence, Meat Animal and Veg. Garden.

Table 2.7-3 [Deleted]

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
SPECIFIC POINTS OF INTEREST

0RELEASE ID	TYPE OF LOCATION	DIRECTION FROM SITE	DISTANCE (MILES)	DISTANCE (METERS)	X/Q (SEC/CUB.METER) NO DECAY UNDEPLETED	X/Q (SEC/CUB.METER) 2.260 DAY DECAY UNDEPLETED	X/Q (SEC/CUB.METER) 8.000 DAY DECAY DEPLETED	D/Q (PER SQ.METER)
A	RESIDENCE	S	0.74	1198.	6.5E-08	6.5E-08	6.2E-08	1.5E-09
A	RESIDENCE	SSW	0.74	1198.	3.2E-08	3.2E-08	3.1E-08	7.7E-10
A	RESIDENCE	SW	0.74	1198.	2.4E-08	2.4E-08	2.3E-08	6.1E-10
A	RESIDENCE	WSW	0.74	1198.	2.3E-08	2.3E-08	2.3E-08	5.9E-10
A	RESIDENCE	W	0.74	1198.	2.8E-08	2.8E-08	2.7E-08	7.3E-10
A	RESIDENCE	WNW	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	8.6E-10
A	RESIDENCE	NW	0.74	1198.	1.9E-08	1.9E-08	1.8E-08	5.1E-10
A	RESIDENCE	NNW	0.74	1198.	1.3E-08	1.3E-08	1.3E-08	3.9E-10
A	RESIDENCE	N	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	1.0E-09
A	RESIDENCE	NNE	0.74	1198.	6.8E-08	6.8E-08	6.6E-08	1.8E-09
A	RESIDENCE	NE	0.74	1198.	4.8E-08	4.8E-08	4.6E-08	1.3E-09
A	RESIDENCE	ENE	0.74	1198.	2.7E-08	2.7E-08	2.6E-08	7.3E-10
A	RESIDENCE	E	0.74	1198.	2.5E-08	2.4E-08	2.4E-08	8.0E-10
A	RESIDENCE	ESE	0.74	1198.	3.9E-08	3.9E-08	3.8E-08	1.2E-09
A	RESIDENCE	SE	0.74	1198.	5.7E-08	5.7E-08	5.5E-08	1.8E-09
A	RESIDENCE	SSE	0.74	1198.	6.3E-08	6.3E-08	6.1E-08	1.7E-09
A	EAB	S	0.62	998.	6.3E-08	6.3E-08	6.0E-08	1.7E-09
A	EAB	SSW	0.57	917.	2.9E-08	2.9E-08	2.8E-08	7.9E-10
A	EAB	SW	0.54	869.	2.2E-08	2.2E-08	2.1E-08	6.3E-10
A	EAB	WSW	0.55	885.	2.1E-08	2.1E-08	2.1E-08	6.4E-10
A	EAB	W	0.54	869.	2.7E-08	2.7E-08	2.6E-08	8.1E-10
A	EAB	WNW	0.56	901.	3.5E-08	3.5E-08	3.4E-08	1.0E-09
A	EAB	NW	0.62	998.	1.8E-08	1.8E-08	1.7E-08	5.5E-10
A	EAB	NNW	0.72	1159.	1.3E-08	1.3E-08	1.3E-08	4.0E-10
A	EAB	N	0.87	1400.	3.8E-08	3.8E-08	3.8E-08	9.3E-10
A	EAB	NNE	0.88	1416.	7.1E-08	7.1E-08	6.9E-08	1.6E-09
A	EAB	NE	0.90	1448.	5.3E-08	5.3E-08	5.2E-08	1.1E-09
A	EAB	ENE	0.91	1465.	2.9E-08	2.9E-08	2.8E-08	6.3E-10
A	EAB	E	0.89	1432.	2.6E-08	2.6E-08	2.6E-08	6.8E-10
A	EAB	ESE	0.88	1416.	4.0E-08	4.0E-08	3.9E-08	1.0E-09
A	EAB	SE	0.83	1336.	5.4E-08	5.4E-08	5.3E-08	1.6E-09
A	EAB	SSE	0.73	1175.	6.3E-08	6.3E-08	6.1E-08	1.7E-09
A	MEAT ANIMAL	S	0.74	1198.	6.5E-08	6.5E-08	6.2E-08	1.5E-09
A	MEAT ANIMAL	SSW	0.74	1198.	3.2E-08	3.2E-08	3.1E-08	7.7E-10
A	MEAT ANIMAL	SW	0.74	1198.	2.4E-08	2.4E-08	2.3E-08	6.1E-10
A	MEAT ANIMAL	WSW	0.74	1198.	2.3E-08	2.3E-08	2.3E-08	5.9E-10
A	MEAT ANIMAL	W	0.74	1198.	2.8E-08	2.8E-08	2.7E-08	7.3E-10
A	MEAT ANIMAL	WNW	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	8.6E-10
A	MEAT ANIMAL	NW	0.74	1198.	1.9E-08	1.9E-08	1.8E-08	5.1E-10
A	MEAT ANIMAL	NNW	0.74	1198.	1.3E-08	1.3E-08	1.3E-08	3.9E-10
A	MEAT ANIMAL	N	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	1.0E-09
A	MEAT ANIMAL	NNE	0.74	1198.	6.8E-08	6.8E-08	6.6E-08	1.8E-09
A	MEAT ANIMAL	NE	0.74	1198.	4.8E-08	4.8E-08	4.6E-08	1.3E-09
A	MEAT ANIMAL	ENE	0.74	1198.	2.7E-08	2.7E-08	2.6E-08	7.3E-10
A	MEAT ANIMAL	E	0.74	1198.	2.5E-08	2.4E-08	2.4E-08	8.0E-10
A	MEAT ANIMAL	ESE	0.74	1198.	3.9E-08	3.9E-08	3.8E-08	1.2E-09
A	MEAT ANIMAL	SE	0.74	1198.	5.7E-08	5.7E-08	5.5E-08	1.8E-09
A	MEAT ANIMAL	SSE	0.74	1198.	6.3E-08	6.3E-08	6.1E-08	1.7E-09
A	VEG. GARDEN	S	0.74	1198.	6.5E-08	6.5E-08	6.2E-08	1.5E-09
A	VEG. GARDEN	SSW	0.74	1198.	3.2E-08	3.2E-08	3.1E-08	7.7E-10
A	VEG. GARDEN	SW	0.74	1198.	2.4E-08	2.4E-08	2.3E-08	6.1E-10
A	VEG. GARDEN	WSW	0.74	1198.	2.3E-08	2.3E-08	2.3E-08	5.9E-10
A	VEG. GARDEN	W	0.74	1198.	2.8E-08	2.8E-08	2.7E-08	7.3E-10
A	VEG. GARDEN	WNW	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	8.6E-10
A	VEG. GARDEN	NW	0.74	1198.	1.9E-08	1.9E-08	1.8E-08	5.1E-10
A	VEG. GARDEN	NNW	0.74	1198.	1.3E-08	1.3E-08	1.3E-08	3.9E-10
A	VEG. GARDEN	N	0.74	1198.	3.5E-08	3.5E-08	3.4E-08	1.0E-09
A	VEG. GARDEN	NNE	0.74	1198.	6.8E-08	6.8E-08	6.6E-08	1.8E-09
A	VEG. GARDEN	NE	0.74	1198.	4.8E-08	4.8E-08	4.6E-08	1.3E-09
A	VEG. GARDEN	ENE	0.74	1198.	2.7E-08	2.7E-08	2.6E-08	7.3E-10
A	VEG. GARDEN	E	0.74	1198.	2.5E-08	2.4E-08	2.4E-08	8.0E-10
A	VEG. GARDEN	ESE	0.74	1198.	3.9E-08	3.9E-08	3.8E-08	1.2E-09
A	VEG. GARDEN	SE	0.74	1198.	5.7E-08	5.7E-08	5.5E-08	1.8E-09
A	VEG. GARDEN	SSE	0.74	1198.	6.3E-08	6.3E-08	6.1E-08	1.7E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	52.77	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	2.40	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	17.78	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):

VENT RELEASE MODE	WIND SPEED (METERS/SEC)	VENT RELEASE MODE	WIND SPEED (METERS/SEC) STABLE CONDITIONS	WIND SPEED (METERS/SEC) UNSTABLE/NEUTRAL CONDITIONS
ELEVATED	LESS THAN 3.556	ELEVATED	LESS THAN 3.556	LESS THAN 3.556
MIXED	BETWEEN 3.556 AND 17.780	MIXED	BETWEEN 3.556 AND 17.780	BETWEEN 3.556 AND 17.780
GROUND LEVEL	ABOVE 17.780	GROUND LEVEL	ABOVE 17.780	ABOVE 17.780

Note: Directions are True North.

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest (Sheet 2 of 4)

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0        RUN DATE:  8/28/2014

0XOQDOQ - North Anna COL (1996-98 Met Data)

 EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
 SPECIFIC POINTS OF INTEREST
0RELEASE     TYPE  OF      DIRECTION       DISTANCE          X/Q             X/Q             X/Q            D/Q
   ID        LOCATION      FROM SITE  (MILES)  (METERS) (SEC/CUB.METER) (SEC/CUB.METER) (SEC/CUB.METER) (PER SQ.METER)
                                                           NO DECAY
+                                                                          2.260 DAY DECAY
+                                                                                          8.000 DAY DECAY
                                                          UNDEPLETED      UNDEPLETED       DEPLETED
    B     RESIDENCE            S         0.74    1198.      4.7E-08         4.7E-08         4.5E-08         1.5E-09
    B     RESIDENCE          SSW         0.74    1198.      2.3E-08         2.3E-08         2.2E-08         7.4E-10
    B     RESIDENCE           SW         0.74    1198.      1.7E-08         1.7E-08         1.6E-08         6.0E-10
    B     RESIDENCE          WSW         0.74    1198.      1.7E-08         1.7E-08         1.7E-08         5.8E-10
    B     RESIDENCE            W         0.74    1198.      2.2E-08         2.2E-08         2.1E-08         7.1E-10
    B     RESIDENCE          WNW         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         8.5E-10
    B     RESIDENCE           NW         0.74    1198.      1.4E-08         1.4E-08         1.4E-08         5.1E-10
    B     RESIDENCE          NNW         0.74    1198.      1.1E-08         1.1E-08         1.1E-08         3.9E-10
    B     RESIDENCE            N         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         1.0E-09
    B     RESIDENCE          NNE         0.74    1198.      5.5E-08         5.5E-08         5.3E-08         1.8E-09
    B     RESIDENCE           NE         0.74    1198.      3.7E-08         3.7E-08         3.5E-08         1.2E-09
    B     RESIDENCE          ENE         0.74    1198.      2.1E-08         2.1E-08         2.1E-08         7.2E-10
    B     RESIDENCE            E         0.74    1198.      1.9E-08         1.9E-08         1.9E-08         7.9E-10
    B     RESIDENCE          ESE         0.74    1198.      3.2E-08         3.2E-08         3.0E-08         1.1E-09
    B     RESIDENCE           SE         0.74    1198.      4.7E-08         4.7E-08         4.6E-08         1.7E-09
    B     RESIDENCE          SSE         0.74    1198.      5.0E-08         5.0E-08         4.8E-08         1.6E-09
    B     EAB                  S         0.62     998.      4.9E-08         4.9E-08         4.7E-08         1.5E-09
    B     EAB                SSW         0.57     917.      2.4E-08         2.4E-08         2.3E-08         7.5E-10
    B     EAB                 SW         0.54     869.      1.9E-08         1.9E-08         1.8E-08         6.1E-10
    B     EAB                WSW         0.55     885.      1.8E-08         1.8E-08         1.7E-08         6.2E-10
    B     EAB                  W         0.54     869.      2.4E-08         2.4E-08         2.3E-08         7.9E-10
    B     EAB                WNW         0.56     901.      3.1E-08         3.1E-08         3.0E-08         1.0E-09
    B     EAB                 NW         0.62     998.      1.5E-08         1.5E-08         1.5E-08         5.5E-10
    B     EAB                NNW         0.72    1159.      1.1E-08         1.1E-08         1.1E-08         4.0E-10
    B     EAB                  N         0.87    1400.      2.7E-08         2.7E-08         2.7E-08         9.3E-10
    B     EAB                NNE         0.88    1416.      5.2E-08         5.2E-08         5.0E-08         1.6E-09
    B     EAB                 NE         0.90    1448.      3.6E-08         3.6E-08         3.5E-08         1.1E-09
    B     EAB                ENE         0.91    1465.      2.0E-08         2.0E-08         1.9E-08         6.2E-10
    B     EAB                  E         0.89    1432.      1.8E-08         1.8E-08         1.7E-08         6.7E-10
    B     EAB                ESE         0.88    1416.      2.9E-08         2.9E-08         2.8E-08         9.8E-10
    B     EAB                 SE         0.83    1336.      4.4E-08         4.4E-08         4.2E-08         1.5E-09
    B     EAB                SSE         0.73    1175.      5.1E-08         5.1E-08         4.9E-08         1.6E-09
    B     MEAT ANIMAL          S         0.74    1198.      4.7E-08         4.7E-08         4.5E-08         1.5E-09
    B     MEAT ANIMAL        SSW         0.74    1198.      2.3E-08         2.3E-08         2.2E-08         7.4E-10
    B     MEAT ANIMAL         SW         0.74    1198.      1.7E-08         1.7E-08         1.6E-08         6.0E-10
    B     MEAT ANIMAL        WSW         0.74    1198.      1.7E-08         1.7E-08         1.7E-08         5.8E-10
    B     MEAT ANIMAL          W         0.74    1198.      2.2E-08         2.2E-08         2.1E-08         7.1E-10
    B     MEAT ANIMAL        WNW         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         8.5E-10
    B     MEAT ANIMAL         NW         0.74    1198.      1.4E-08         1.4E-08         1.4E-08         5.1E-10
    B     MEAT ANIMAL        NNW         0.74    1198.      1.1E-08         1.1E-08         1.1E-08         3.9E-10
    B     MEAT ANIMAL          N         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         1.0E-09
    B     MEAT ANIMAL        NNE         0.74    1198.      5.5E-08         5.5E-08         5.3E-08         1.8E-09
    B     MEAT ANIMAL         NE         0.74    1198.      3.7E-08         3.7E-08         3.5E-08         1.2E-09
    B     MEAT ANIMAL        ENE         0.74    1198.      2.1E-08         2.1E-08         2.1E-08         7.2E-10
    B     MEAT ANIMAL          E         0.74    1198.      1.9E-08         1.9E-08         1.9E-08         7.9E-10
    B     MEAT ANIMAL        ESE         0.74    1198.      3.2E-08         3.2E-08         3.0E-08         1.1E-09
    B     MEAT ANIMAL         SE         0.74    1198.      4.7E-08         4.7E-08         4.6E-08         1.7E-09
    B     MEAT ANIMAL        SSE         0.74    1198.      5.0E-08         5.0E-08         4.8E-08         1.6E-09
    B     VEG. GARDEN          S         0.74    1198.      4.7E-08         4.7E-08         4.5E-08         1.5E-09
    B     VEG. GARDEN        SSW         0.74    1198.      2.3E-08         2.3E-08         2.2E-08         7.4E-10
    B     VEG. GARDEN         SW         0.74    1198.      1.7E-08         1.7E-08         1.6E-08         6.0E-10
    B     VEG. GARDEN        WSW         0.74    1198.      1.7E-08         1.7E-08         1.7E-08         5.8E-10
    B     VEG. GARDEN          W         0.74    1198.      2.2E-08         2.2E-08         2.1E-08         7.1E-10
    B     VEG. GARDEN        WNW         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         8.5E-10
    B     VEG. GARDEN         NW         0.74    1198.      1.4E-08         1.4E-08         1.4E-08         5.1E-10
    B     VEG. GARDEN        NNW         0.74    1198.      1.1E-08         1.1E-08         1.1E-08         3.9E-10
    B     VEG. GARDEN          N         0.74    1198.      2.9E-08         2.9E-08         2.8E-08         1.0E-09
    B     VEG. GARDEN        NNE         0.74    1198.      5.5E-08         5.5E-08         5.3E-08         1.8E-09
    B     VEG. GARDEN         NE         0.74    1198.      3.7E-08         3.7E-08         3.5E-08         1.2E-09
    B     VEG. GARDEN        ENE         0.74    1198.      2.1E-08         2.1E-08         2.1E-08         7.2E-10
    B     VEG. GARDEN          E         0.74    1198.      1.9E-08         1.9E-08         1.9E-08         7.9E-10
    B     VEG. GARDEN        ESE         0.74    1198.      3.2E-08         3.2E-08         3.0E-08         1.1E-09
    B     VEG. GARDEN         SE         0.74    1198.      4.7E-08         4.7E-08         4.6E-08         1.7E-09
    B     VEG. GARDEN        SSE         0.74    1198.      5.0E-08         5.0E-08         4.8E-08         1.6E-09
0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)   71.30                 REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    1.95                 BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)   17.78                 BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                      HEAT EMISSION RATE     (CAL/SEC)       0.0
0AT THE RELEASE HEIGHT:                         /  AT THE MEASURED WIND HEIGHT ( 10.0 METERS):
 VENT RELEASE MODE   WIND SPEED (METERS/SEC)    /  VENT RELEASE MODE   WIND SPEED (METERS/SEC)       WIND SPEED (METERS/SEC)
                                              /                      STABLE CONDITIONS          UNSTABLE/NEUTRAL CONDITIONS
     ELEVATED        LESS THAN  3.556           /      ELEVATED        LESS THAN  3.556              LESS THAN  3.556
    MIXED          BETWEEN    3.556 AND 17.780 /     MIXED          BETWEEN    3.556 AND 17.780  BETWEEN    3.556 AND 17.780
     GROUND LEVEL    ABOVE     17.780           /      GROUND LEVEL    ABOVE     17.780              ABOVE     17.780
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Note: Directions are True North.

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest (Sheet 3 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
SPECIFIC POINTS OF INTEREST

0RELEASE ID	TYPE OF LOCATION	DIRECTION FROM SITE	DISTANCE (MILES)	DISTANCE (METERS)	X/Q (SEC/CUB.METER) NO DECAY UNDEPLETED	X/Q (SEC/CUB.METER) 2.260 DAY DECAY UNDEPLETED	X/Q (SEC/CUB.METER) 8.000 DAY DECAY DEPLETED	D/Q (PER SQ.METER)
A	RESIDENCE	S	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	8.5E-09
A	RESIDENCE	SSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	5.6E-09
A	RESIDENCE	SW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	4.6E-09
A	RESIDENCE	WSW	0.74	1198.	1.1E-06	1.1E-06	9.6E-07	4.0E-09
A	RESIDENCE	W	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.7E-09
A	RESIDENCE	WNW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.4E-09
A	RESIDENCE	NW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	3.9E-09
A	RESIDENCE	NNW	0.74	1198.	9.9E-07	9.9E-07	8.8E-07	2.9E-09
A	RESIDENCE	N	0.74	1198.	2.5E-06	2.5E-06	2.3E-06	7.6E-09
A	RESIDENCE	NNE	0.74	1198.	3.2E-06	3.2E-06	2.9E-06	1.1E-08
A	RESIDENCE	NE	0.74	1198.	2.6E-06	2.6E-06	2.3E-06	8.9E-09
A	RESIDENCE	ENE	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	4.8E-09
A	RESIDENCE	E	0.74	1198.	3.0E-06	2.9E-06	2.6E-06	6.7E-09
A	RESIDENCE	ESE	0.74	1198.	4.2E-06	4.2E-06	3.8E-06	9.0E-09
A	RESIDENCE	SE	0.74	1198.	3.0E-06	3.0E-06	2.7E-06	8.0E-09
A	RESIDENCE	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09
A	EAB	S	0.62	998.	2.2E-06	2.2E-06	2.0E-06	1.1E-08
A	EAB	SSW	0.57	917.	2.0E-06	1.9E-06	1.8E-06	8.7E-09
A	EAB	SW	0.54	869.	1.9E-06	1.9E-06	1.7E-06	7.9E-09
A	EAB	WSW	0.55	885.	1.7E-06	1.7E-06	1.6E-06	6.6E-09
A	EAB	W	0.54	869.	2.1E-06	2.1E-06	1.9E-06	8.0E-09
A	EAB	WNW	0.56	901.	1.7E-06	1.7E-06	1.6E-06	7.0E-09
A	EAB	NW	0.62	998.	1.5E-06	1.5E-06	1.4E-06	5.3E-09
A	EAB	NNW	0.72	1159.	1.0E-06	1.0E-06	9.3E-07	3.0E-09
A	EAB	N	0.87	1400.	2.0E-06	2.0E-06	1.8E-06	5.8E-09
A	EAB	NNE	0.88	1416.	2.5E-06	2.5E-06	2.2E-06	8.3E-09
A	EAB	NE	0.90	1448.	2.0E-06	2.0E-06	1.7E-06	6.4E-09
A	EAB	ENE	0.91	1465.	1.2E-06	1.2E-06	1.0E-06	3.4E-09
A	EAB	E	0.89	1432.	2.3E-06	2.3E-06	2.0E-06	5.0E-09
A	EAB	ESE	0.88	1416.	3.3E-06	3.3E-06	2.9E-06	6.8E-09
A	EAB	SE	0.83	1336.	2.5E-06	2.5E-06	2.2E-06	6.7E-09
A	EAB	SSE	0.73	1175.	1.7E-06	1.7E-06	1.5E-06	7.4E-09
A	MEAT ANIMAL	S	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	8.5E-09
A	MEAT ANIMAL	SSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	5.6E-09
A	MEAT ANIMAL	SW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	4.6E-09
A	MEAT ANIMAL	WSW	0.74	1198.	1.1E-06	1.1E-06	9.6E-07	4.0E-09
A	MEAT ANIMAL	W	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.7E-09
A	MEAT ANIMAL	WNW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.4E-09
A	MEAT ANIMAL	NW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	3.9E-09
A	MEAT ANIMAL	NNW	0.74	1198.	9.9E-07	9.9E-07	8.8E-07	2.9E-09
A	MEAT ANIMAL	N	0.74	1198.	2.5E-06	2.5E-06	2.3E-06	7.6E-09
A	MEAT ANIMAL	NNE	0.74	1198.	3.2E-06	3.2E-06	2.9E-06	1.1E-08
A	MEAT ANIMAL	NE	0.74	1198.	2.6E-06	2.6E-06	2.3E-06	8.9E-09
A	MEAT ANIMAL	ENE	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	4.8E-09
A	MEAT ANIMAL	E	0.74	1198.	3.0E-06	2.9E-06	2.6E-06	6.7E-09
A	MEAT ANIMAL	ESE	0.74	1198.	4.2E-06	4.2E-06	3.8E-06	9.0E-09
A	MEAT ANIMAL	SE	0.74	1198.	3.0E-06	3.0E-06	2.7E-06	8.0E-09
A	MEAT ANIMAL	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09
A	VEG. GARDEN	S	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	8.5E-09
A	VEG. GARDEN	SSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	5.6E-09
A	VEG. GARDEN	SW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	4.6E-09
A	VEG. GARDEN	WSW	0.74	1198.	1.1E-06	1.1E-06	9.6E-07	4.0E-09
A	VEG. GARDEN	W	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.7E-09
A	VEG. GARDEN	WNW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.4E-09
A	VEG. GARDEN	NW	0.74	1198.	1.2E-06	1.2E-06	1.0E-06	3.9E-09
A	VEG. GARDEN	NNW	0.74	1198.	9.9E-07	9.9E-07	8.8E-07	2.9E-09
A	VEG. GARDEN	N	0.74	1198.	2.5E-06	2.5E-06	2.3E-06	7.6E-09
A	VEG. GARDEN	NNE	0.74	1198.	3.2E-06	3.2E-06	2.9E-06	1.1E-08
A	VEG. GARDEN	NE	0.74	1198.	2.6E-06	2.6E-06	2.3E-06	8.9E-09
A	VEG. GARDEN	ENE	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	4.8E-09
A	VEG. GARDEN	E	0.74	1198.	3.0E-06	2.9E-06	2.6E-06	6.7E-09
A	VEG. GARDEN	ESE	0.74	1198.	4.2E-06	4.2E-06	3.8E-06	9.0E-09
A	VEG. GARDEN	SE	0.74	1198.	3.0E-06	3.0E-06	2.7E-06	8.0E-09
A	VEG. GARDEN	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	0.00	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0ALL GROUND LEVEL RELEASES.

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
SPECIFIC POINTS OF INTEREST

0RELEASE ID	TYPE OF LOCATION	DIRECTION FROM SITE	DISTANCE (MILES)	DISTANCE (METERS)	X/Q (SEC/CUB.METER) NO DECAY UNDEPLETED	X/Q (SEC/CUB.METER) + 2.260 DAY DECAY UNDEPLETED	X/Q (SEC/CUB.METER) + 8.000 DAY DECAY DEPLETED	D/Q (PER SQ.METER)
H	RESIDENCE	S	0.74	1198.	2.0E-06	1.9E-06	1.7E-06	8.5E-09
H	RESIDENCE	SSW	0.74	1198.	1.6E-06	1.5E-06	1.4E-06	5.6E-09
H	RESIDENCE	SW	0.74	1198.	1.4E-06	1.4E-06	1.2E-06	4.6E-09
H	RESIDENCE	WSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.0E-09
H	RESIDENCE	W	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	4.7E-09
H	RESIDENCE	WNW	0.74	1198.	1.4E-06	1.4E-06	1.3E-06	4.4E-09
H	RESIDENCE	NW	0.74	1198.	1.5E-06	1.5E-06	1.3E-06	3.9E-09
H	RESIDENCE	NNW	0.74	1198.	1.3E-06	1.2E-06	1.1E-06	2.9E-09
H	RESIDENCE	N	0.74	1198.	3.2E-06	3.2E-06	2.8E-06	7.6E-09
H	RESIDENCE	NNE	0.74	1198.	4.0E-06	4.0E-06	3.6E-06	1.1E-08
H	RESIDENCE	NE	0.74	1198.	3.3E-06	3.3E-06	3.0E-06	8.9E-09
H	RESIDENCE	ENE	0.74	1198.	2.1E-06	2.1E-06	1.9E-06	4.8E-09
H	RESIDENCE	E	0.74	1198.	4.1E-06	4.1E-06	3.7E-06	6.7E-09
H	RESIDENCE	ESE	0.74	1198.	6.3E-06	6.2E-06	5.6E-06	9.0E-09
H	RESIDENCE	SE	0.74	1198.	4.3E-06	4.3E-06	3.9E-06	8.0E-09
H	RESIDENCE	SSE	0.74	1198.	2.2E-06	2.2E-06	1.9E-06	7.2E-09
H	EAB	S	0.43	687.	5.2E-06	5.2E-06	4.8E-06	2.1E-08
H	EAB	SSW	0.37	589.	5.4E-06	5.4E-06	5.0E-06	1.8E-08
H	EAB	SW	0.34	552.	5.5E-06	5.5E-06	5.1E-06	1.6E-08
H	EAB	WSW	0.34	552.	5.1E-06	5.1E-06	4.8E-06	1.4E-08
H	EAB	W	0.34	552.	6.4E-06	6.4E-06	6.0E-06	1.7E-08
H	EAB	WNW	0.37	589.	4.9E-06	4.9E-06	4.6E-06	1.4E-08
H	EAB	NW	0.42	675.	4.0E-06	4.0E-06	3.7E-06	1.0E-08
H	EAB	NNW	0.53	859.	2.2E-06	2.2E-06	2.0E-06	5.0E-09
H	EAB	N	0.71	1135.	3.5E-06	3.5E-06	3.1E-06	8.3E-09
H	EAB	NNE	0.95	1534.	2.7E-06	2.6E-06	2.3E-06	7.2E-09
H	EAB	NE	1.20	1939.	1.5E-06	1.5E-06	1.3E-06	3.9E-09
H	EAB	ENE	1.39	2240.	7.5E-07	7.4E-07	6.4E-07	1.6E-09
H	EAB	E	1.21	1945.	1.9E-06	1.8E-06	1.6E-06	2.9E-09
H	EAB	ESE	0.98	1577.	4.0E-06	3.9E-06	3.5E-06	5.6E-09
H	EAB	SE	0.74	1184.	4.4E-06	4.4E-06	4.0E-06	8.2E-09
H	EAB	SSE	0.55	878.	3.8E-06	3.7E-06	3.4E-06	1.2E-08
H	MEAT ANIMAL	SSW	0.74	1198.	1.6E-06	1.5E-06	1.4E-06	5.6E-09
H	MEAT ANIMAL	SW	0.74	1198.	1.4E-06	1.4E-06	1.2E-06	4.6E-09
H	MEAT ANIMAL	WSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.0E-09
H	MEAT ANIMAL	W	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	4.7E-09
H	MEAT ANIMAL	WNW	0.74	1198.	1.4E-06	1.4E-06	1.3E-06	4.4E-09
H	MEAT ANIMAL	NW	0.74	1198.	1.5E-06	1.5E-06	1.3E-06	3.9E-09
H	MEAT ANIMAL	NNW	0.74	1198.	1.3E-06	1.2E-06	1.1E-06	2.9E-09
H	MEAT ANIMAL	N	0.74	1198.	3.2E-06	3.2E-06	2.8E-06	7.6E-09
H	MEAT ANIMAL	NNE	0.74	1198.	4.0E-06	4.0E-06	3.6E-06	1.1E-08
H	MEAT ANIMAL	NE	0.74	1198.	3.3E-06	3.3E-06	3.0E-06	8.9E-09
H	MEAT ANIMAL	ENE	0.74	1198.	2.1E-06	2.1E-06	1.9E-06	4.8E-09
H	MEAT ANIMAL	E	0.74	1198.	4.1E-06	4.1E-06	3.7E-06	6.7E-09
H	MEAT ANIMAL	ESE	0.74	1198.	6.3E-06	6.2E-06	5.6E-06	9.0E-09
H	MEAT ANIMAL	SE	0.74	1198.	4.3E-06	4.3E-06	3.9E-06	8.0E-09
H	MEAT ANIMAL	SSE	0.74	1198.	2.2E-06	2.2E-06	1.9E-06	7.2E-09
H	VEG. GARDEN	S	0.74	1198.	2.0E-06	1.9E-06	1.7E-06	8.5E-09
H	VEG. GARDEN	SSW	0.74	1198.	1.6E-06	1.5E-06	1.4E-06	5.6E-09
H	VEG. GARDEN	SW	0.74	1198.	1.4E-06	1.4E-06	1.2E-06	4.6E-09
H	VEG. GARDEN	WSW	0.74	1198.	1.3E-06	1.3E-06	1.2E-06	4.0E-09
H	VEG. GARDEN	W	0.74	1198.	1.6E-06	1.6E-06	1.5E-06	4.7E-09
H	VEG. GARDEN	WNW	0.74	1198.	1.4E-06	1.4E-06	1.3E-06	4.4E-09
H	VEG. GARDEN	NW	0.74	1198.	1.5E-06	1.5E-06	1.3E-06	3.9E-09
H	VEG. GARDEN	NNW	0.74	1198.	1.3E-06	1.2E-06	1.1E-06	2.9E-09
H	VEG. GARDEN	N	0.74	1198.	3.2E-06	3.2E-06	2.8E-06	7.6E-09
H	VEG. GARDEN	NNE	0.74	1198.	4.0E-06	4.0E-06	3.6E-06	1.1E-08
H	VEG. GARDEN	NE	0.74	1198.	3.3E-06	3.3E-06	3.0E-06	8.9E-09
H	VEG. GARDEN	ENE	0.74	1198.	2.1E-06	2.1E-06	1.9E-06	4.8E-09
H	VEG. GARDEN	E	0.74	1198.	4.1E-06	4.1E-06	3.7E-06	6.7E-09
H	VEG. GARDEN	ESE	0.74	1198.	6.3E-06	6.2E-06	5.6E-06	9.0E-09
H	VEG. GARDEN	SE	0.74	1198.	4.3E-06	4.3E-06	3.9E-06	8.0E-09
H	VEG. GARDEN	SSE	0.74	1198.	2.2E-06	2.2E-06	1.9E-06	7.2E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	0.00	BUILDING HEIGHT	(METERS)	0.0
EXIT VELOCITY	(METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	0.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0ALL GROUND LEVEL RELEASES.

Note: Directions are True North.

Table 2.7-5 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, No Decay, Undepleted (Sheet 1 of 4)

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0          RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
 NO DECAY,  UNDEPLETED
0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
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SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.215E-07	6.850E-08	6.533E-08	7.487E-08	8.482E-08	8.163E-08	7.439E-08	6.675E-08	5.975E-08	5.363E-08	4.836E-08
SSW	5.450E-08	3.120E-08	3.230E-08	4.172E-08	5.403E-08	5.532E-08	5.227E-08	4.804E-08	4.377E-08	3.981E-08	3.628E-08
SW	4.108E-08	2.332E-08	2.410E-08	3.227E-08	4.374E-08	4.576E-08	4.381E-08	4.064E-08	3.728E-08	3.411E-08	3.122E-08
WSW	3.446E-08	2.254E-08	2.357E-08	2.932E-08	3.737E-08	3.866E-08	3.708E-08	3.459E-08	3.193E-08	2.937E-08	2.703E-08
W	4.658E-08	2.971E-08	2.844E-08	3.446E-08	4.328E-08	4.447E-08	4.252E-08	3.961E-08	3.656E-08	3.366E-08	3.100E-08
WNW	4.676E-08	3.794E-08	3.545E-08	3.894E-08	4.490E-08	4.478E-08	4.207E-08	3.868E-08	3.533E-08	3.224E-08	2.949E-08
NW	2.899E-08	2.013E-08	1.912E-08	2.602E-08	3.864E-08	4.243E-08	4.170E-08	3.930E-08	3.643E-08	3.358E-08	3.093E-08
NNW	3.068E-08	1.997E-08	1.382E-08	1.696E-08	2.674E-08	3.105E-08	3.171E-08	3.072E-08	2.908E-08	2.724E-08	2.542E-08
N	8.469E-08	4.920E-08	3.659E-08	4.590E-08	7.175E-08	8.282E-08	8.430E-08	8.149E-08	7.702E-08	7.208E-08	6.720E-08
NNE	1.495E-07	8.914E-08	6.988E-08	7.852E-08	1.039E-07	1.125E-07	1.110E-07	1.054E-07	9.853E-08	9.149E-08	8.481E-08
NE	1.070E-07	5.723E-08	4.874E-08	5.915E-08	8.211E-08	8.991E-08	8.903E-08	8.467E-08	7.917E-08	7.353E-08	6.817E-08
ENE	7.397E-08	3.692E-08	2.785E-08	3.128E-08	4.206E-08	4.634E-08	4.640E-08	4.461E-08	4.213E-08	3.948E-08	3.688E-08
E	8.171E-08	3.661E-08	2.533E-08	3.063E-08	4.870E-08	5.852E-08	6.186E-08	6.179E-08	6.007E-08	5.760E-08	5.485E-08
ESE	1.130E-07	5.568E-08	4.030E-08	4.415E-08	6.015E-08	6.798E-08	6.973E-08	6.847E-08	6.586E-08	6.273E-08	5.948E-08
SE	1.522E-07	8.406E-08	5.817E-08	5.493E-08	5.937E-08	5.990E-08	5.768E-08	5.439E-08	5.084E-08	4.738E-08	4.416E-08
SSE	1.199E-07	7.853E-08	6.419E-08	6.486E-08	6.805E-08	6.486E-08	5.942E-08	5.379E-08	4.862E-08	4.404E-08	4.005E-08

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0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
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SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	4.383E-08	2.875E-08	2.063E-08	1.253E-08	8.675E-09	6.485E-09	5.099E-09	4.155E-09	3.477E-09	2.970E-09	2.579E-09
SSW	3.316E-08	2.233E-08	1.624E-08	1.000E-08	6.972E-09	5.232E-09	4.125E-09	3.367E-09	2.822E-09	2.413E-09	2.097E-09
SW	2.865E-08	1.954E-08	1.432E-08	8.907E-09	6.247E-09	4.710E-09	3.726E-09	3.051E-09	2.563E-09	2.196E-09	1.912E-09
WSW	2.492E-08	1.730E-08	1.281E-08	8.065E-09	5.702E-09	4.323E-09	3.434E-09	2.822E-09	2.378E-09	2.043E-09	1.782E-09
W	2.862E-08	2.000E-08	1.491E-08	9.498E-09	6.780E-09	5.182E-09	4.145E-09	3.426E-09	2.902E-09	2.505E-09	2.195E-09
WNW	2.707E-08	1.862E-08	1.378E-08	8.734E-09	6.239E-09	4.774E-09	3.823E-09	3.164E-09	2.682E-09	2.318E-09	2.033E-09
NW	2.853E-08	1.985E-08	1.477E-08	9.404E-09	6.722E-09	5.144E-09	4.121E-09	3.409E-09	2.890E-09	2.497E-09	2.189E-09
NNW	2.370E-08	1.706E-08	1.293E-08	8.397E-09	6.059E-09	4.665E-09	3.752E-09	3.114E-09	2.646E-09	2.289E-09	2.010E-09
N	6.261E-08	4.498E-08	3.404E-08	2.206E-08	1.590E-08	1.223E-08	9.824E-09	8.145E-09	6.913E-09	5.977E-09	5.244E-09
NNE	7.870E-08	5.597E-08	4.222E-08	2.732E-08	1.970E-08	1.516E-08	1.219E-08	1.012E-08	8.598E-09	7.440E-09	6.533E-09
NE	6.325E-08	4.493E-08	3.387E-08	2.189E-08	1.578E-08	1.214E-08	9.763E-09	8.102E-09	6.884E-09	5.958E-09	5.232E-09
ENE	3.446E-08	2.515E-08	1.931E-08	1.280E-08	9.376E-09	7.306E-09	5.933E-09	4.965E-09	4.248E-09	3.698E-09	3.265E-09
E	5.207E-08	4.012E-08	3.186E-08	2.202E-08	1.657E-08	1.317E-08	1.086E-08	9.196E-09	7.949E-09	6.982E-09	6.211E-09
ESE	5.632E-08	4.337E-08	3.468E-08	2.442E-08	1.871E-08	1.511E-08	1.263E-08	1.083E-08	9.467E-09	8.399E-09	7.540E-09
SE	4.125E-08	3.040E-08	2.370E-08	1.623E-08	1.225E-08	9.805E-09	8.151E-09	6.963E-09	6.069E-09	5.374E-09	4.817E-09
SSE	3.660E-08	2.486E-08	1.831E-08	1.157E-08	8.267E-09	6.338E-09	5.090E-09	4.224E-09	3.593E-09	3.114E-09	2.739E-09

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0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)   52.77                   REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    2.40                   BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)   17.78                   BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                        HEAT EMISSION RATE     (CAL/SEC)       0.0
0AT THE RELEASE HEIGHT:                          /  AT THE MEASURED WIND HEIGHT ( 10.0 METERS):
 VENT RELEASE MODE   WIND SPEED (METERS/SEC)     /  VENT RELEASE MODE   WIND SPEED (METERS/SEC)       WIND SPEED (METERS/SEC)
                                                 /                      STABLE CONDITIONS             UNSTABLE/NEUTRAL CONDITIONS
     ELEVATED        LESS THAN  3.556            /      ELEVATED        LESS THAN  3.556              LESS THAN  3.556
     MIXED           BETWEEN    3.556 AND 17.780 /      MIXED           BETWEEN    3.556 AND 17.780   BETWEEN    3.556 AND 17.780
     GROUND LEVEL    ABOVE     17.780            /      GROUND LEVEL    ABOVE     17.780              ABOVE     17.780
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Note: Directions are True North.

Table 2.7-5 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, No Decay, Undepleted (Sheet 2 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.147E-07	5.912E-08	4.785E-08	5.254E-08	6.329E-08	6.493E-08	6.190E-08	5.730E-08	5.244E-08	4.784E-08	4.366E-08
SSW	5.197E-08	2.729E-08	2.301E-08	2.804E-08	3.902E-08	4.298E-08	4.271E-08	4.064E-08	3.793E-08	3.511E-08	3.241E-08
SW	3.866E-08	2.069E-08	1.738E-08	2.166E-08	3.127E-08	3.515E-08	3.541E-08	3.402E-08	3.200E-08	2.980E-08	2.765E-08
WSW	3.221E-08	1.974E-08	1.770E-08	2.053E-08	2.708E-08	2.984E-08	3.005E-08	2.900E-08	2.742E-08	2.567E-08	2.393E-08
W	4.366E-08	2.686E-08	2.209E-08	2.471E-08	3.166E-08	3.437E-08	3.432E-08	3.299E-08	3.113E-08	2.912E-08	2.714E-08
WNW	4.287E-08	3.378E-08	2.939E-08	2.983E-08	3.313E-08	3.400E-08	3.304E-08	3.124E-08	2.916E-08	2.707E-08	2.508E-08
NW	2.612E-08	1.808E-08	1.485E-08	1.724E-08	2.515E-08	2.947E-08	3.062E-08	3.006E-08	2.873E-08	2.710E-08	2.541E-08
NNW	2.768E-08	1.883E-08	1.150E-08	1.104E-08	1.605E-08	2.010E-08	2.199E-08	2.242E-08	2.203E-08	2.123E-08	2.025E-08
N	7.522E-08	4.563E-08	2.991E-08	2.954E-08	4.271E-08	5.325E-08	5.813E-08	5.918E-08	5.811E-08	5.597E-08	5.335E-08
NNE	1.330E-07	8.002E-08	5.611E-08	5.368E-08	6.653E-08	7.601E-08	7.916E-08	7.836E-08	7.555E-08	7.187E-08	6.789E-08
NE	9.706E-08	5.066E-08	3.734E-08	3.839E-08	5.136E-08	6.011E-08	6.316E-08	6.278E-08	6.065E-08	5.775E-08	5.459E-08
ENE	6.623E-08	3.337E-08	2.189E-08	2.066E-08	2.601E-08	3.028E-08	3.202E-08	3.209E-08	3.127E-08	3.002E-08	2.859E-08
E	7.219E-08	3.341E-08	2.009E-08	1.895E-08	2.721E-08	3.485E-08	3.916E-08	4.096E-08	4.122E-08	4.060E-08	3.951E-08
ESE	1.009E-07	5.030E-08	3.241E-08	2.978E-08	3.669E-08	4.301E-08	4.613E-08	4.694E-08	4.640E-08	4.515E-08	4.354E-08
SE	1.348E-07	7.571E-08	4.873E-08	4.191E-08	4.236E-08	4.353E-08	4.323E-08	4.185E-08	3.992E-08	3.779E-08	3.563E-08
SSE	1.092E-07	6.871E-08	5.128E-08	4.905E-08	5.158E-08	5.106E-08	4.843E-08	4.502E-08	4.149E-08	3.815E-08	3.508E-08

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	3.995E-08	2.689E-08	1.951E-08	1.196E-08	8.316E-09	6.229E-09	4.903E-09	3.997E-09	3.346E-09	2.859E-09	2.482E-09
SSW	2.993E-08	2.072E-08	1.526E-08	9.498E-09	6.653E-09	5.007E-09	3.954E-09	3.231E-09	2.710E-09	2.319E-09	2.016E-09
SW	2.563E-08	1.800E-08	1.336E-08	8.405E-09	5.927E-09	4.483E-09	3.553E-09	2.913E-09	2.450E-09	2.101E-09	1.830E-09
WSW	2.229E-08	1.590E-08	1.191E-08	7.578E-09	5.384E-09	4.093E-09	3.258E-09	2.680E-09	2.260E-09	1.943E-09	1.697E-09
W	2.528E-08	1.812E-08	1.366E-08	8.782E-09	6.297E-09	4.825E-09	3.866E-09	3.199E-09	2.712E-09	2.342E-09	2.054E-09
WNW	2.328E-08	1.654E-08	1.244E-08	8.012E-09	5.772E-09	4.440E-09	3.569E-09	2.961E-09	2.515E-09	2.177E-09	1.912E-09
NW	2.378E-08	1.728E-08	1.313E-08	8.545E-09	6.177E-09	4.761E-09	3.832E-09	3.181E-09	2.704E-09	2.341E-09	2.056E-09
NNW	1.922E-08	1.457E-08	1.134E-08	7.563E-09	5.537E-09	4.303E-09	3.483E-09	2.904E-09	2.477E-09	2.150E-09	1.893E-09
N	5.061E-08	3.835E-08	2.983E-08	1.989E-08	1.456E-08	1.131E-08	9.148E-09	7.625E-09	6.499E-09	5.638E-09	4.961E-09
NNE	6.398E-08	4.769E-08	3.687E-08	2.450E-08	1.793E-08	1.393E-08	1.128E-08	9.413E-09	8.031E-09	6.974E-09	6.141E-09
NE	5.145E-08	3.831E-08	2.958E-08	1.962E-08	1.434E-08	1.113E-08	9.008E-09	7.512E-09	6.407E-09	5.562E-09	4.897E-09
ENE	2.713E-08	2.078E-08	1.637E-08	1.115E-08	8.300E-09	6.534E-09	5.346E-09	4.498E-09	3.866E-09	3.378E-09	2.992E-09
E	3.818E-08	3.112E-08	2.549E-08	1.825E-08	1.401E-08	1.128E-08	9.389E-09	8.010E-09	6.965E-09	6.146E-09	5.490E-09
ESE	4.180E-08	3.354E-08	2.737E-08	1.966E-08	1.522E-08	1.237E-08	1.039E-08	8.942E-09	7.839E-09	6.972E-09	6.273E-09
SE	3.358E-08	2.532E-08	1.988E-08	1.363E-08	1.028E-08	8.212E-09	6.817E-09	5.816E-09	5.066E-09	4.483E-09	4.017E-09
SSE	3.235E-08	2.250E-08	1.672E-08	1.064E-08	7.612E-09	5.835E-09	4.683E-09	3.884E-09	3.300E-09	2.858E-09	2.512E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	71.30	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	1.95	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	17.78	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):

VENT RELEASE MODE	WIND SPEED (METERS/SEC)	/	VENT RELEASE MODE	WIND SPEED (METERS/SEC) STABLE CONDITIONS	WIND SPEED (METERS/SEC) UNSTABLE/NEUTRAL CONDITIONS
ELEVATED	LESS THAN 3.556	/	ELEVATED	LESS THAN 3.556	LESS THAN 3.556
MIXED	BETWEEN 3.556 AND 17.780	/	MIXED	BETWEEN 3.556 AND 17.780	BETWEEN 3.556 AND 17.780
GROUND LEVEL	ABOVE 17.780	/	GROUND LEVEL	ABOVE 17.780	ABOVE 17.780

Note: Directions are True North.

Table 2.7-5 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, No Decay, Undepleted (Sheet 3 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	8.557E-06	3.035E-06	1.618E-06	1.035E-06	5.561E-07	3.586E-07	2.555E-07	1.939E-07	1.538E-07	1.258E-07	1.055E-07
SSW	6.692E-06	2.387E-06	1.281E-06	8.219E-07	4.431E-07	2.864E-07	2.044E-07	1.553E-07	1.233E-07	1.010E-07	8.472E-08
SW	5.993E-06	2.128E-06	1.143E-06	7.348E-07	3.972E-07	2.571E-07	1.838E-07	1.399E-07	1.111E-07	9.113E-08	7.654E-08
WSW	5.628E-06	1.979E-06	1.062E-06	6.824E-07	3.695E-07	2.396E-07	1.715E-07	1.307E-07	1.039E-07	8.530E-08	7.169E-08
W	7.005E-06	2.408E-06	1.286E-06	8.272E-07	4.513E-07	2.943E-07	2.117E-07	1.619E-07	1.292E-07	1.063E-07	8.961E-08
WNW	6.098E-06	2.086E-06	1.117E-06	7.181E-07	3.907E-07	2.544E-07	1.828E-07	1.397E-07	1.115E-07	9.173E-08	7.729E-08
NW	6.083E-06	2.108E-06	1.143E-06	7.395E-07	4.052E-07	2.651E-07	1.912E-07	1.465E-07	1.172E-07	9.661E-08	8.154E-08
NNW	5.158E-06	1.787E-06	9.783E-07	6.369E-07	3.503E-07	2.297E-07	1.659E-07	1.274E-07	1.019E-07	8.414E-08	7.108E-08
N	1.311E-05	4.572E-06	2.516E-06	1.640E-06	8.999E-07	5.891E-07	4.249E-07	3.257E-07	2.605E-07	2.148E-07	1.813E-07
NNE	1.674E-05	5.775E-06	3.165E-06	2.064E-06	1.134E-06	7.425E-07	5.358E-07	4.109E-07	3.287E-07	2.711E-07	2.289E-07
NE	1.366E-05	4.720E-06	2.583E-06	1.683E-06	9.262E-07	6.076E-07	4.390E-07	3.370E-07	2.698E-07	2.227E-07	1.881E-07
ENE	8.564E-06	2.868E-06	1.566E-06	1.025E-06	5.709E-07	3.777E-07	2.747E-07	2.120E-07	1.705E-07	1.412E-07	1.197E-07
E	1.674E-05	5.376E-06	2.919E-06	1.921E-06	1.089E-06	7.297E-07	5.356E-07	4.165E-07	3.371E-07	2.808E-07	2.391E-07
ESE	2.574E-05	8.002E-06	4.182E-06	2.707E-06	1.560E-06	1.059E-06	7.848E-07	6.153E-07	5.012E-07	4.200E-07	3.595E-07
SE	1.829E-05	5.731E-06	2.952E-06	1.888E-06	1.080E-06	7.295E-07	5.392E-07	4.218E-07	3.430E-07	2.870E-07	2.453E-07
SSE	9.435E-06	3.165E-06	1.663E-06	1.062E-06	5.835E-07	3.829E-07	2.767E-07	2.126E-07	1.703E-07	1.406E-07	1.189E-07

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	9.015E-08	4.946E-08	3.242E-08	1.799E-08	1.191E-08	8.665E-09	6.692E-09	5.384E-09	4.462E-09	3.783E-09	3.265E-09
SSW	7.245E-08	3.984E-08	2.616E-08	1.453E-08	9.620E-09	6.999E-09	5.404E-09	4.346E-09	3.601E-09	3.053E-09	2.634E-09
SW	6.551E-08	3.614E-08	2.379E-08	1.327E-08	8.809E-09	6.424E-09	4.969E-09	4.003E-09	3.321E-09	2.819E-09	2.435E-09
WSW	6.141E-08	3.400E-08	2.243E-08	1.256E-08	8.366E-09	6.116E-09	4.741E-09	3.827E-09	3.180E-09	2.703E-09	2.338E-09
W	7.695E-08	4.302E-08	2.860E-08	1.619E-08	1.087E-08	7.997E-09	6.232E-09	5.053E-09	4.217E-09	3.596E-09	3.121E-09
WNW	6.637E-08	3.714E-08	2.470E-08	1.401E-08	9.435E-09	6.957E-09	5.432E-09	4.410E-09	3.685E-09	3.146E-09	2.733E-09
NW	7.011E-08	3.938E-08	2.626E-08	1.493E-08	1.005E-08	7.411E-09	5.785E-09	4.695E-09	3.922E-09	3.347E-09	2.906E-09
NNW	6.116E-08	3.445E-08	2.302E-08	1.311E-08	8.831E-09	6.512E-09	5.083E-09	4.126E-09	3.445E-09	2.940E-09	2.553E-09
N	1.559E-07	8.755E-08	5.837E-08	3.315E-08	2.228E-08	1.640E-08	1.278E-08	1.036E-08	8.642E-09	7.367E-09	6.390E-09
NNE	1.969E-07	1.107E-07	7.388E-08	4.201E-08	2.827E-08	2.083E-08	1.625E-08	1.318E-08	1.100E-08	9.388E-09	8.147E-09
NE	1.618E-07	9.115E-08	6.089E-08	3.468E-08	2.336E-08	1.722E-08	1.344E-08	1.091E-08	9.112E-09	7.777E-09	6.751E-09
ENE	1.033E-07	5.889E-08	3.967E-08	2.286E-08	1.552E-08	1.152E-08	9.035E-09	7.365E-09	6.174E-09	5.287E-09	4.603E-09
E	2.072E-07	1.199E-07	8.167E-08	4.776E-08	3.276E-08	2.450E-08	1.934E-08	1.585E-08	1.335E-08	1.148E-08	1.003E-08
ESE	3.130E-07	1.843E-07	1.270E-07	7.556E-08	5.246E-08	3.960E-08	3.150E-08	2.599E-08	2.201E-08	1.902E-08	1.669E-08
SE	2.134E-07	1.253E-07	8.621E-08	5.120E-08	3.553E-08	2.681E-08	2.133E-08	1.760E-08	1.491E-08	1.288E-08	1.131E-08
SSE	1.024E-07	5.791E-08	3.884E-08	2.228E-08	1.512E-08	1.122E-08	8.804E-09	7.181E-09	6.023E-09	5.162E-09	4.498E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	0.00	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0ALL GROUND LEVEL RELEASES.

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-5 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, No Decay, Undepleted (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.356E-05	3.928E-06	1.928E-06	1.186E-06	6.109E-07	3.861E-07	2.719E-07	2.048E-07	1.615E-07	1.316E-07	1.100E-07
SSW	1.072E-05	3.119E-06	1.534E-06	9.444E-07	4.874E-07	3.084E-07	2.175E-07	1.640E-07	1.294E-07	1.056E-07	8.827E-08
SW	9.638E-06	2.807E-06	1.381E-06	8.500E-07	4.390E-07	2.781E-07	1.963E-07	1.481E-07	1.170E-07	9.552E-08	7.994E-08
WSW	9.049E-06	2.632E-06	1.293E-06	7.957E-07	4.111E-07	2.606E-07	1.841E-07	1.391E-07	1.099E-07	8.978E-08	7.518E-08
W	1.131E-05	3.284E-06	1.608E-06	9.898E-07	5.127E-07	3.260E-07	2.310E-07	1.749E-07	1.386E-07	1.134E-07	9.519E-08
WNW	9.801E-06	2.841E-06	1.391E-06	8.537E-07	4.413E-07	2.803E-07	1.984E-07	1.502E-07	1.190E-07	9.738E-08	8.172E-08
NW	1.001E-05	2.927E-06	1.439E-06	8.852E-07	4.593E-07	2.927E-07	2.078E-07	1.576E-07	1.251E-07	1.026E-07	8.620E-08
NNW	8.566E-06	2.510E-06	1.236E-06	7.606E-07	3.954E-07	2.524E-07	1.794E-07	1.363E-07	1.083E-07	8.887E-08	7.474E-08
N	2.178E-05	6.394E-06	3.154E-06	1.940E-06	1.007E-06	6.422E-07	4.561E-07	3.462E-07	2.749E-07	2.254E-07	1.895E-07
NNE	2.770E-05	8.114E-06	3.995E-06	2.457E-06	1.276E-06	8.135E-07	5.778E-07	4.386E-07	3.483E-07	2.857E-07	2.401E-07
NE	2.271E-05	6.664E-06	3.282E-06	2.020E-06	1.050E-06	6.701E-07	4.763E-07	3.618E-07	2.874E-07	2.358E-07	1.983E-07
ENE	1.437E-05	4.211E-06	2.067E-06	1.274E-06	6.647E-07	4.261E-07	3.040E-07	2.317E-07	1.846E-07	1.519E-07	1.281E-07
E	2.851E-05	8.354E-06	4.085E-06	2.521E-06	1.323E-06	8.528E-07	6.116E-07	4.683E-07	3.746E-07	3.094E-07	2.617E-07
ESE	4.394E-05	1.279E-05	6.200E-06	3.832E-06	2.022E-06	1.310E-06	9.443E-07	7.261E-07	5.831E-07	4.832E-07	4.100E-07
SE	3.069E-05	8.874E-06	4.292E-06	2.651E-06	1.396E-06	9.027E-07	6.494E-07	4.986E-07	3.999E-07	3.311E-07	2.807E-07
SSE	1.522E-05	4.392E-06	2.139E-06	1.316E-06	6.834E-07	4.359E-07	3.097E-07	2.352E-07	1.868E-07	1.533E-07	1.289E-07

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	9.375E-08	5.103E-08	3.332E-08	1.841E-08	1.216E-08	8.834E-09	6.815E-09	5.478E-09	4.538E-09	3.845E-09	3.318E-09
SSW	7.529E-08	4.107E-08	2.685E-08	1.486E-08	9.810E-09	7.126E-09	5.497E-09	4.417E-09	3.658E-09	3.099E-09	2.673E-09
SW	6.823E-08	3.733E-08	2.446E-08	1.358E-08	8.993E-09	6.547E-09	5.058E-09	4.071E-09	3.376E-09	2.863E-09	2.472E-09
WSW	6.421E-08	3.523E-08	2.314E-08	1.289E-08	8.560E-09	6.247E-09	4.836E-09	3.900E-09	3.239E-09	2.751E-09	2.378E-09
W	8.145E-08	4.505E-08	2.977E-08	1.675E-08	1.120E-08	8.224E-09	6.399E-09	5.181E-09	4.319E-09	3.681E-09	3.192E-09
WNW	6.993E-08	3.872E-08	2.561E-08	1.444E-08	9.687E-09	7.127E-09	5.556E-09	4.506E-09	3.761E-09	3.209E-09	2.785E-09
NW	7.385E-08	4.103E-08	2.720E-08	1.537E-08	1.031E-08	7.585E-09	5.911E-09	4.792E-09	3.999E-09	3.410E-09	2.959E-09
NNW	6.408E-08	3.570E-08	2.372E-08	1.343E-08	9.014E-09	6.632E-09	5.169E-09	4.191E-09	3.497E-09	2.982E-09	2.587E-09
N	1.624E-07	9.026E-08	5.985E-08	3.379E-08	2.264E-08	1.663E-08	1.295E-08	1.048E-08	8.738E-09	7.445E-09	6.453E-09
NNE	2.058E-07	1.145E-07	7.596E-08	4.294E-08	2.880E-08	2.117E-08	1.649E-08	1.337E-08	1.115E-08	9.502E-09	8.241E-09
NE	1.700E-07	9.468E-08	6.287E-08	3.558E-08	2.388E-08	1.757E-08	1.369E-08	1.110E-08	9.260E-09	7.897E-09	6.851E-09
ENE	1.101E-07	6.187E-08	4.138E-08	2.365E-08	1.599E-08	1.183E-08	9.261E-09	7.538E-09	6.311E-09	5.398E-09	4.696E-09
E	2.255E-07	1.283E-07	8.651E-08	5.006E-08	3.414E-08	2.543E-08	2.002E-08	1.638E-08	1.377E-08	1.182E-08	1.032E-08
ESE	3.544E-07	2.039E-07	1.388E-07	8.136E-08	5.602E-08	4.206E-08	3.333E-08	2.741E-08	2.316E-08	1.997E-08	1.749E-08
SE	2.424E-07	1.391E-07	9.455E-08	5.536E-08	3.810E-08	2.859E-08	2.266E-08	1.863E-08	1.574E-08	1.357E-08	1.190E-08
SSE	1.106E-07	6.173E-08	4.110E-08	2.339E-08	1.580E-08	1.168E-08	9.150E-09	7.450E-09	6.241E-09	5.341E-09	4.650E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	0.00	BUILDING HEIGHT	(METERS)	0.0
EXIT VELOCITY	(METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	0.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

Note: Directions are True North.

Table 2.7-6 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, No Decay, Undepleted (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

SEGMENT BOUNDARIES IN MILES FROM THE SITE

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	7.027E-08	8.119E-08	7.326E-08	5.942E-08	4.824E-08	2.849E-08	1.261E-08	6.515E-09	4.166E-09	2.975E-09
SSW	3.625E-08	5.187E-08	5.139E-08	4.348E-08	3.617E-08	2.203E-08	1.004E-08	5.253E-09	3.376E-09	2.417E-09
SW	2.756E-08	4.209E-08	4.306E-08	3.703E-08	3.112E-08	1.925E-08	8.929E-09	4.726E-09	3.058E-09	2.200E-09
WSW	2.590E-08	3.616E-08	3.651E-08	3.171E-08	2.694E-08	1.700E-08	8.069E-09	4.335E-09	2.828E-09	2.045E-09
W	3.140E-08	4.185E-08	4.188E-08	3.633E-08	3.090E-08	1.965E-08	9.493E-09	5.193E-09	3.432E-09	2.508E-09
WNW	3.756E-08	4.352E-08	4.144E-08	3.511E-08	2.941E-08	1.835E-08	8.746E-09	4.784E-09	3.169E-09	2.320E-09
NW	2.241E-08	3.752E-08	4.093E-08	3.616E-08	3.083E-08	1.952E-08	9.404E-09	5.155E-09	3.415E-09	2.499E-09
NNW	1.658E-08	2.648E-08	3.114E-08	2.885E-08	2.532E-08	1.670E-08	8.366E-09	4.672E-09	3.118E-09	2.291E-09
N	4.353E-08	7.093E-08	8.278E-08	7.642E-08	6.694E-08	4.404E-08	2.199E-08	1.225E-08	8.155E-09	5.983E-09
NNE	7.800E-08	1.021E-07	1.092E-07	9.783E-08	8.453E-08	5.491E-08	2.724E-08	1.518E-08	1.013E-08	7.447E-09
NE	5.525E-08	8.047E-08	8.752E-08	7.859E-08	6.794E-08	4.409E-08	2.184E-08	1.216E-08	8.112E-09	5.963E-09
ENE	3.139E-08	4.157E-08	4.567E-08	4.183E-08	3.676E-08	2.462E-08	1.272E-08	7.309E-09	4.968E-09	3.701E-09
E	3.019E-08	4.905E-08	6.094E-08	5.962E-08	5.463E-08	3.910E-08	2.179E-08	1.315E-08	9.195E-09	6.983E-09
ESE	4.543E-08	6.008E-08	6.876E-08	6.541E-08	5.927E-08	4.239E-08	2.417E-08	1.508E-08	1.083E-08	8.397E-09
SE	6.248E-08	5.862E-08	5.695E-08	5.053E-08	4.404E-08	2.983E-08	1.612E-08	9.797E-09	6.962E-09	5.374E-09
SSE	6.768E-08	6.592E-08	5.862E-08	4.835E-08	3.995E-08	2.456E-08	1.160E-08	6.353E-09	4.231E-09	3.117E-09

0AVERAGE EFFECTIVE STACK HEIGHT IN METERS FOR EACH SEGMENT

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02	1.039E+02
SSW	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02	1.091E+02
SW	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02	1.111E+02
WSW	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02	1.144E+02
W	1.138E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02	1.139E+02
WNW	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02	1.100E+02
NW	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02	1.061E+02
NNW	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02	1.090E+02
N	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02	1.069E+02
NNE	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02	1.023E+02
NE	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02	1.005E+02
ENE	9.853E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01	9.854E+01
E	9.598E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01	9.599E+01
ESE	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01	9.461E+01
SE	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02	1.016E+02
SSE	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02	1.050E+02

Note: Directions are True North.

Table 2.7-6 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, No Decay, Undepleted (Sheet 2 of 4)

```
1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0          RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
 NO DECAY,  UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT
```

SEGMENT BOUNDARIES IN MILES FROM THE SITE

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	5.244E-08	6.163E-08	6.087E-08	5.207E-08	4.352E-08	2.651E-08	1.202E-08	6.255E-09	4.008E-09	2.864E-09
SSW	2.619E-08	3.834E-08	4.196E-08	3.763E-08	3.229E-08	2.034E-08	9.513E-09	5.025E-09	3.239E-09	2.322E-09
SW	2.002E-08	3.086E-08	3.479E-08	3.174E-08	2.754E-08	1.763E-08	8.405E-09	4.496E-09	2.920E-09	2.104E-09
WSW	1.941E-08	2.685E-08	2.957E-08	2.721E-08	2.384E-08	1.555E-08	7.566E-09	4.103E-09	2.686E-09	1.946E-09
W	2.431E-08	3.132E-08	3.380E-08	3.089E-08	2.704E-08	1.773E-08	8.760E-09	4.834E-09	3.204E-09	2.345E-09
WNW	3.056E-08	3.279E-08	3.258E-08	2.896E-08	2.500E-08	1.621E-08	8.000E-09	4.447E-09	2.965E-09	2.179E-09
NW	1.663E-08	2.532E-08	3.009E-08	2.849E-08	2.531E-08	1.688E-08	8.512E-09	4.767E-09	3.185E-09	2.343E-09
NNW	1.292E-08	1.673E-08	2.166E-08	2.184E-08	2.016E-08	1.417E-08	7.502E-09	4.304E-09	2.907E-09	2.152E-09
N	3.324E-08	4.447E-08	5.725E-08	5.760E-08	5.311E-08	3.729E-08	1.973E-08	1.131E-08	7.631E-09	5.643E-09
NNE	6.034E-08	6.788E-08	7.800E-08	7.495E-08	6.762E-08	4.650E-08	2.433E-08	1.394E-08	9.420E-09	6.979E-09
NE	4.076E-08	5.237E-08	6.220E-08	6.015E-08	5.436E-08	3.735E-08	1.949E-08	1.114E-08	7.519E-09	5.566E-09
ENE	2.389E-08	2.672E-08	3.159E-08	3.103E-08	2.847E-08	2.023E-08	1.104E-08	6.530E-09	4.500E-09	3.380E-09
E	2.254E-08	2.877E-08	3.873E-08	4.091E-08	3.934E-08	3.019E-08	1.798E-08	1.125E-08	8.006E-09	6.146E-09
ESE	3.522E-08	3.796E-08	4.562E-08	4.608E-08	4.337E-08	3.263E-08	1.940E-08	1.234E-08	8.935E-09	6.970E-09
SE	5.170E-08	4.278E-08	4.276E-08	3.966E-08	3.551E-08	2.474E-08	1.353E-08	8.206E-09	5.816E-09	4.483E-09
SSE	5.416E-08	5.079E-08	4.777E-08	4.123E-08	3.498E-08	2.212E-08	1.065E-08	5.848E-09	3.890E-09	2.861E-09

0AVERAGE EFFECTIVE STACK HEIGHT IN METERS FOR EACH SEGMENT

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.130E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02	1.131E+02
SSW	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02	1.174E+02
SW	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02	1.190E+02
WSW	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02	1.217E+02
W	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02	1.214E+02
WNW	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02	1.184E+02
NW	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02	1.155E+02
NNW	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02	1.180E+02
N	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02	1.163E+02
NNE	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02	1.124E+02
NE	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02	1.110E+02
ENE	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02	1.094E+02
E	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02	1.077E+02
ESE	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02	1.065E+02
SE	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02	1.118E+02
SSE	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02	1.141E+02

Note: Directions are True North.

Table 2.7-6 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, No Decay, Undepleted (Sheet 3 of 4)

```
1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
 NO DECAY,  UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT
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DIRECTION FROM SITE	SEGMENT BOUNDARIES IN MILES FROM THE SITE .5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.674E-06	5.747E-07	2.584E-07	1.546E-07	1.058E-07	5.093E-08	1.850E-08	8.741E-09	5.406E-09	3.792E-09
SSW	1.323E-06	4.576E-07	2.066E-07	1.239E-07	8.500E-08	4.101E-08	1.493E-08	7.060E-09	4.365E-09	3.060E-09
SW	1.181E-06	4.100E-07	1.858E-07	1.117E-07	7.678E-08	3.718E-08	1.363E-08	6.478E-09	4.019E-09	2.825E-09
WSW	1.097E-06	3.813E-07	1.733E-07	1.045E-07	7.191E-08	3.495E-08	1.289E-08	6.166E-09	3.842E-09	2.709E-09
W	1.331E-06	4.651E-07	2.138E-07	1.298E-07	8.988E-08	4.415E-08	1.658E-08	8.057E-09	5.071E-09	3.604E-09
WNW	1.155E-06	4.029E-07	1.847E-07	1.120E-07	7.752E-08	3.811E-08	1.435E-08	7.008E-09	4.426E-09	3.153E-09
NW	1.178E-06	4.172E-07	1.930E-07	1.177E-07	8.177E-08	4.038E-08	1.528E-08	7.465E-09	4.712E-09	3.354E-09
NNW	1.006E-06	3.604E-07	1.675E-07	1.024E-07	7.127E-08	3.530E-08	1.341E-08	6.558E-09	4.140E-09	2.946E-09
N	2.583E-06	9.262E-07	4.290E-07	2.617E-07	1.818E-07	8.977E-08	3.392E-08	1.652E-08	1.040E-08	7.383E-09
NNE	3.256E-06	1.166E-06	5.410E-07	3.303E-07	2.296E-07	1.135E-07	4.299E-08	2.098E-08	1.323E-08	9.407E-09
NE	2.658E-06	9.528E-07	4.432E-07	2.710E-07	1.886E-07	9.341E-08	3.547E-08	1.735E-08	1.095E-08	7.793E-09
ENE	1.615E-06	5.860E-07	2.771E-07	1.712E-07	1.200E-07	6.023E-08	2.333E-08	1.159E-08	7.389E-09	5.296E-09
E	3.022E-06	1.114E-06	5.397E-07	3.383E-07	2.397E-07	1.223E-07	4.863E-08	2.464E-08	1.590E-08	1.149E-08
ESE	4.375E-06	1.592E-06	7.900E-07	5.029E-07	3.602E-07	1.874E-07	7.673E-08	3.979E-08	2.605E-08	1.904E-08
SE	3.097E-06	1.104E-06	5.430E-07	3.442E-07	2.458E-07	1.275E-07	5.201E-08	2.694E-08	1.764E-08	1.290E-08
SSE	1.730E-06	6.008E-07	2.794E-07	1.711E-07	1.192E-07	5.931E-08	2.278E-08	1.129E-08	7.204E-09	5.171E-09

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-6 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, No Decay, Undepleted (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

SEGMENT BOUNDARIES IN MILES FROM THE SITE

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	2.043E-06	6.387E-07	2.755E-07	1.625E-07	1.104E-07	5.265E-08	1.895E-08	8.913E-09	5.502E-09	3.855E-09
SSW	1.624E-06	5.094E-07	2.203E-07	1.302E-07	8.859E-08	4.235E-08	1.528E-08	7.190E-09	4.436E-09	3.107E-09
SW	1.462E-06	4.588E-07	1.988E-07	1.177E-07	8.022E-08	3.848E-08	1.396E-08	6.604E-09	4.088E-09	2.870E-09
WSW	1.370E-06	4.297E-07	1.865E-07	1.106E-07	7.544E-08	3.629E-08	1.324E-08	6.300E-09	3.915E-09	2.757E-09
W	1.706E-06	5.358E-07	2.339E-07	1.394E-07	9.550E-08	4.635E-08	1.718E-08	8.288E-09	5.201E-09	3.689E-09
WNW	1.474E-06	4.614E-07	2.010E-07	1.197E-07	8.199E-08	3.983E-08	1.481E-08	7.181E-09	4.522E-09	3.215E-09
NW	1.523E-06	4.799E-07	2.104E-07	1.258E-07	8.648E-08	4.218E-08	1.575E-08	7.643E-09	4.810E-09	3.417E-09
NNW	1.308E-06	4.130E-07	1.816E-07	1.089E-07	7.498E-08	3.668E-08	1.375E-08	6.682E-09	4.206E-09	2.988E-09
N	3.334E-06	1.052E-06	4.618E-07	2.764E-07	1.901E-07	9.277E-08	3.463E-08	1.676E-08	1.052E-08	7.461E-09
NNE	4.227E-06	1.333E-06	5.850E-07	3.502E-07	2.409E-07	1.177E-07	4.399E-08	2.133E-08	1.341E-08	9.522E-09
NE	3.473E-06	1.097E-06	4.822E-07	2.890E-07	1.990E-07	9.728E-08	3.644E-08	1.770E-08	1.114E-08	7.914E-09
ENE	2.191E-06	6.940E-07	3.076E-07	1.856E-07	1.285E-07	6.347E-08	2.418E-08	1.191E-08	7.563E-09	5.409E-09
E	4.338E-06	1.380E-06	6.186E-07	3.765E-07	2.624E-07	1.313E-07	5.108E-08	2.559E-08	1.642E-08	1.184E-08
ESE	6.611E-06	2.108E-06	9.547E-07	5.859E-07	4.111E-07	2.084E-07	8.285E-08	4.229E-08	2.748E-08	2.000E-08
SE	4.581E-06	1.456E-06	6.566E-07	4.019E-07	2.814E-07	1.423E-07	5.639E-08	2.875E-08	1.868E-08	1.360E-08
SSE	2.274E-06	7.140E-07	3.135E-07	1.879E-07	1.294E-07	6.342E-08	2.395E-08	1.177E-08	7.475E-09	5.352E-09

Note: Directions are True North.

Table 2.7-7 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 2.260 Day Decay, Undepleted (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
2.260 DAY DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.215E-07	6.844E-08	6.524E-08	7.472E-08	8.453E-08	8.122E-08	7.390E-08	6.619E-08	5.915E-08	5.299E-08	4.769E-08
SSW	5.448E-08	3.117E-08	3.226E-08	4.163E-08	5.383E-08	5.501E-08	5.188E-08	4.759E-08	4.327E-08	3.928E-08	3.571E-08
SW	4.106E-08	2.330E-08	2.407E-08	3.220E-08	4.356E-08	4.548E-08	4.345E-08	4.022E-08	3.682E-08	3.361E-08	3.070E-08
WSW	3.445E-08	2.252E-08	2.353E-08	2.925E-08	3.721E-08	3.842E-08	3.677E-08	3.422E-08	3.151E-08	2.892E-08	2.655E-08
W	4.656E-08	2.967E-08	2.839E-08	3.437E-08	4.309E-08	4.418E-08	4.215E-08	3.919E-08	3.609E-08	3.314E-08	3.045E-08
WNW	4.674E-08	3.789E-08	3.538E-08	3.883E-08	4.469E-08	4.447E-08	4.169E-08	3.825E-08	3.485E-08	3.173E-08	2.895E-08
NW	2.897E-08	2.010E-08	1.908E-08	2.594E-08	3.845E-08	4.213E-08	4.131E-08	3.884E-08	3.593E-08	3.304E-08	3.036E-08
NNW	3.066E-08	1.994E-08	1.379E-08	1.690E-08	2.658E-08	3.078E-08	3.134E-08	3.028E-08	2.859E-08	2.671E-08	2.485E-08
N	8.464E-08	4.913E-08	3.651E-08	4.575E-08	7.132E-08	8.212E-08	8.336E-08	8.037E-08	7.576E-08	7.071E-08	6.574E-08
NNE	1.494E-07	8.904E-08	6.976E-08	7.831E-08	1.034E-07	1.117E-07	1.099E-07	1.041E-07	9.707E-08	8.990E-08	8.312E-08
NE	1.070E-07	5.717E-08	4.866E-08	5.900E-08	8.171E-08	8.926E-08	8.817E-08	8.365E-08	7.802E-08	7.229E-08	6.685E-08
ENE	7.393E-08	3.688E-08	2.780E-08	3.120E-08	4.185E-08	4.598E-08	4.592E-08	4.403E-08	4.147E-08	3.875E-08	3.611E-08
E	8.167E-08	3.657E-08	2.528E-08	3.054E-08	4.840E-08	5.798E-08	6.112E-08	6.087E-08	5.900E-08	5.641E-08	5.356E-08
ESE	1.130E-07	5.562E-08	4.024E-08	4.404E-08	5.982E-08	6.741E-08	6.895E-08	6.751E-08	6.475E-08	6.149E-08	5.814E-08
SE	1.522E-07	8.396E-08	5.807E-08	5.479E-08	5.909E-08	5.946E-08	5.710E-08	5.370E-08	5.006E-08	4.653E-08	4.324E-08
SSE	1.199E-07	7.844E-08	6.409E-08	6.472E-08	6.778E-08	6.447E-08	5.895E-08	5.325E-08	4.802E-08	4.340E-08	3.937E-08

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	4.314E-08	2.803E-08	1.991E-08	1.185E-08	8.047E-09	5.896E-09	4.543E-09	3.627E-09	2.975E-09	2.490E-09	2.119E-09
SSW	3.258E-08	2.170E-08	1.561E-08	9.408E-09	6.415E-09	4.709E-09	3.631E-09	2.900E-09	2.377E-09	1.988E-09	1.690E-09
SW	2.810E-08	1.896E-08	1.373E-08	8.344E-09	5.717E-09	4.210E-09	3.253E-09	2.601E-09	2.135E-09	1.787E-09	1.520E-09
WSW	2.442E-08	1.674E-08	1.225E-08	7.522E-09	5.187E-09	3.835E-09	2.972E-09	2.381E-09	1.957E-09	1.640E-09	1.396E-09
W	2.804E-08	1.936E-08	1.426E-08	8.857E-09	6.165E-09	4.594E-09	3.583E-09	2.888E-09	2.384E-09	2.007E-09	1.715E-09
WNW	2.652E-08	1.802E-08	1.318E-08	8.154E-09	5.684E-09	4.244E-09	3.317E-09	2.679E-09	2.217E-09	1.869E-09	1.600E-09
NW	2.794E-08	1.921E-08	1.412E-08	8.781E-09	6.127E-09	4.577E-09	3.579E-09	2.891E-09	2.392E-09	2.018E-09	1.727E-09
NNW	2.311E-08	1.641E-08	1.227E-08	7.750E-09	5.441E-09	4.076E-09	3.190E-09	2.576E-09	2.130E-09	1.794E-09	1.533E-09
N	6.108E-08	4.329E-08	3.233E-08	2.039E-08	1.430E-08	1.070E-08	8.372E-09	6.757E-09	5.584E-09	4.701E-09	4.017E-09
NNE	7.693E-08	5.401E-08	4.022E-08	2.535E-08	1.781E-08	1.336E-08	1.047E-08	8.466E-09	7.011E-09	5.913E-09	5.062E-09
NE	6.187E-08	4.340E-08	3.230E-08	2.036E-08	1.430E-08	1.073E-08	8.414E-09	6.808E-09	5.642E-09	4.762E-09	4.079E-09
ENE	3.364E-08	2.422E-08	1.834E-08	1.182E-08	8.422E-09	6.382E-09	5.042E-09	4.103E-09	3.415E-09	2.893E-09	2.485E-09
E	5.070E-08	3.849E-08	3.012E-08	2.022E-08	1.477E-08	1.140E-08	9.126E-09	7.507E-09	6.303E-09	5.377E-09	4.648E-09
ESE	5.489E-08	4.166E-08	3.283E-08	2.244E-08	1.669E-08	1.308E-08	1.062E-08	8.837E-09	7.498E-09	6.457E-09	5.628E-09
SE	4.028E-08	2.927E-08	2.250E-08	1.497E-08	1.098E-08	8.532E-09	6.888E-09	5.714E-09	4.837E-09	4.159E-09	3.621E-09
SSE	3.591E-08	2.411E-08	1.754E-08	1.082E-08	7.546E-09	5.644E-09	4.422E-09	3.580E-09	2.970E-09	2.510E-09	2.154E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	52.77	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	2.40	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	17.78	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):

VENT RELEASE MODE	WIND SPEED (METERS/SEC)	/	VENT RELEASE MODE	WIND SPEED (METERS/SEC) STABLE CONDITIONS	WIND SPEED (METERS/SEC) UNSTABLE/NEUTRAL CONDITIONS
ELEVATED	LESS THAN 3.556	/	ELEVATED	LESS THAN 3.556	LESS THAN 3.556
MIXED	BETWEEN 3.556 AND 17.780	/	MIXED	BETWEEN 3.556 AND 17.780	BETWEEN 3.556 AND 17.780
GROUND LEVEL	ABOVE 17.780	/	GROUND LEVEL	ABOVE 17.780	ABOVE 17.780

Note: Directions are True North.

Table 2.7-7 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 2.260 Day Decay, Undepleted (Sheet 2 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
2.260 DAY DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.147E-07	5.906E-08	4.779E-08	5.244E-08	6.308E-08	6.462E-08	6.150E-08	5.682E-08	5.191E-08	4.727E-08	4.306E-08
SSW	5.195E-08	2.726E-08	2.297E-08	2.798E-08	3.888E-08	4.275E-08	4.240E-08	4.026E-08	3.750E-08	3.464E-08	3.192E-08
SW	3.865E-08	2.067E-08	1.735E-08	2.161E-08	3.114E-08	3.495E-08	3.513E-08	3.368E-08	3.161E-08	2.937E-08	2.719E-08
WSW	3.220E-08	1.972E-08	1.767E-08	2.048E-08	2.697E-08	2.966E-08	2.980E-08	2.870E-08	2.707E-08	2.529E-08	2.351E-08
W	4.364E-08	2.683E-08	2.204E-08	2.464E-08	3.153E-08	3.415E-08	3.404E-08	3.264E-08	3.073E-08	2.867E-08	2.666E-08
WNW	4.285E-08	3.373E-08	2.932E-08	2.974E-08	3.298E-08	3.378E-08	3.276E-08	3.090E-08	2.878E-08	2.665E-08	2.464E-08
NW	2.610E-08	1.806E-08	1.482E-08	1.719E-08	2.503E-08	2.927E-08	3.034E-08	2.972E-08	2.834E-08	2.668E-08	2.496E-08
NNW	2.766E-08	1.880E-08	1.147E-08	1.100E-08	1.596E-08	1.993E-08	2.175E-08	2.211E-08	2.167E-08	2.083E-08	1.981E-08
N	7.517E-08	4.557E-08	2.985E-08	2.945E-08	4.247E-08	5.282E-08	5.750E-08	5.839E-08	5.718E-08	5.492E-08	5.221E-08
NNE	1.329E-07	7.992E-08	5.602E-08	5.354E-08	6.623E-08	7.548E-08	7.841E-08	7.743E-08	7.447E-08	7.065E-08	6.658E-08
NE	9.702E-08	5.061E-08	3.728E-08	3.830E-08	5.114E-08	5.971E-08	6.258E-08	6.205E-08	5.980E-08	5.680E-08	5.356E-08
ENE	6.620E-08	3.333E-08	2.186E-08	2.061E-08	2.589E-08	3.006E-08	3.171E-08	3.170E-08	3.080E-08	2.949E-08	2.801E-08
E	7.216E-08	3.338E-08	2.006E-08	1.890E-08	2.706E-08	3.455E-08	3.871E-08	4.037E-08	4.051E-08	3.979E-08	3.860E-08
ESE	1.009E-07	5.025E-08	3.236E-08	2.971E-08	3.651E-08	4.268E-08	4.564E-08	4.631E-08	4.566E-08	4.429E-08	4.259E-08
SE	1.348E-07	7.561E-08	4.865E-08	4.181E-08	4.218E-08	4.324E-08	4.282E-08	4.135E-08	3.934E-08	3.713E-08	3.492E-08
SSE	1.092E-07	6.862E-08	5.119E-08	4.894E-08	5.138E-08	5.077E-08	4.806E-08	4.458E-08	4.100E-08	3.761E-08	3.451E-08

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	3.932E-08	2.622E-08	1.884E-08	1.132E-08	7.721E-09	5.670E-09	4.375E-09	3.497E-09	2.870E-09	2.404E-09	2.047E-09
SSW	2.941E-08	2.015E-08	1.467E-08	8.940E-09	6.127E-09	4.512E-09	3.486E-09	2.787E-09	2.287E-09	1.915E-09	1.629E-09
SW	2.516E-08	1.746E-08	1.282E-08	7.880E-09	5.430E-09	4.012E-09	3.108E-09	2.489E-09	2.045E-09	1.714E-09	1.459E-09
WSW	2.185E-08	1.539E-08	1.139E-08	7.074E-09	4.904E-09	3.637E-09	2.824E-09	2.267E-09	1.865E-09	1.564E-09	1.333E-09
W	2.478E-08	1.755E-08	1.307E-08	8.198E-09	5.735E-09	4.286E-09	3.350E-09	2.704E-09	2.235E-09	1.883E-09	1.610E-09
WNW	2.282E-08	1.602E-08	1.190E-08	7.488E-09	5.266E-09	3.954E-09	3.103E-09	2.513E-09	2.084E-09	1.761E-09	1.510E-09
NW	2.330E-08	1.673E-08	1.257E-08	7.987E-09	5.638E-09	4.242E-09	3.334E-09	2.703E-09	2.244E-09	1.897E-09	1.627E-09
NNW	1.875E-08	1.403E-08	1.076E-08	6.986E-09	4.976E-09	3.763E-09	2.964E-09	2.406E-09	1.997E-09	1.687E-09	1.446E-09
N	4.939E-08	3.693E-08	2.834E-08	1.839E-08	1.310E-08	9.908E-09	7.805E-09	6.334E-09	5.257E-09	4.442E-09	3.806E-09
NNE	6.258E-08	4.606E-08	3.515E-08	2.276E-08	1.623E-08	1.229E-08	9.702E-09	7.890E-09	6.562E-09	5.555E-09	4.769E-09
NE	5.035E-08	3.703E-08	2.824E-08	1.826E-08	1.301E-08	9.851E-09	7.775E-09	6.324E-09	5.261E-09	4.455E-09	3.827E-09
ENE	2.651E-08	2.002E-08	1.556E-08	1.032E-08	7.469E-09	5.720E-09	4.553E-09	3.727E-09	3.117E-09	2.650E-09	2.284E-09
E	3.719E-08	2.988E-08	2.413E-08	1.677E-08	1.251E-08	9.778E-09	7.905E-09	6.552E-09	5.534E-09	4.745E-09	4.118E-09
ESE	4.077E-08	3.225E-08	2.594E-08	1.810E-08	1.361E-08	1.074E-08	8.760E-09	7.322E-09	6.234E-09	5.384E-09	4.705E-09
SE	3.282E-08	2.441E-08	1.890E-08	1.260E-08	9.240E-09	7.173E-09	5.787E-09	4.798E-09	4.061E-09	3.493E-09	3.042E-09
SSE	3.175E-08	2.183E-08	1.604E-08	9.965E-09	6.964E-09	5.212E-09	4.084E-09	3.306E-09	2.742E-09	2.318E-09	1.989E-09

0VENT AND BUILDING PARAMETERS:
RELEASE HEIGHT (METERS) 71.30 REP. WIND HEIGHT (METERS) 10.0
DIAMETER (METERS) 1.95 BUILDING HEIGHT (METERS) 46.1
EXIT VELOCITY (METERS) 17.78 BLDG.MIN.CRS.SEC.AREA (SQ.METERS) 3098.0
HEAT EMISSION RATE (CAL/SEC) 0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):
VENT RELEASE MODE WIND SPEED (METERS/SEC) / VENT RELEASE MODE WIND SPEED (METERS/SEC) WIND SPEED (METERS/SEC)
/ STABLE CONDITIONS UNSTABLE/NEUTRAL CONDITIONS
ELEVATED LESS THAN 3.556 / ELEVATED LESS THAN 3.556 LESS THAN 3.556
MIXED BETWEEN 3.556 AND 17.780 / MIXED BETWEEN 3.556 AND 17.780 BETWEEN 3.556 AND 17.780
GROUND LEVEL ABOVE 17.780 / GROUND LEVEL ABOVE 17.780 ABOVE 17.780

Note: Directions are True North.

Table 2.7-7 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 2.260 Day Decay, Undepleted (Sheet 3 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES

2.260 DAY DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	8.548E-06	3.029E-06	1.613E-06	1.031E-06	5.527E-07	3.556E-07	2.528E-07	1.915E-07	1.515E-07	1.237E-07	1.035E-07
SSW	6.685E-06	2.381E-06	1.276E-06	8.183E-07	4.402E-07	2.838E-07	2.021E-07	1.532E-07	1.213E-07	9.914E-08	8.299E-08
SW	5.986E-06	2.123E-06	1.139E-06	7.314E-07	3.944E-07	2.547E-07	1.816E-07	1.379E-07	1.093E-07	8.938E-08	7.488E-08
WSW	5.620E-06	1.974E-06	1.058E-06	6.790E-07	3.667E-07	2.372E-07	1.693E-07	1.287E-07	1.021E-07	8.355E-08	7.004E-08
W	6.996E-06	2.402E-06	1.281E-06	8.230E-07	4.478E-07	2.913E-07	2.089E-07	1.593E-07	1.268E-07	1.041E-07	8.749E-08
WNW	6.090E-06	2.081E-06	1.112E-06	7.145E-07	3.878E-07	2.519E-07	1.805E-07	1.376E-07	1.095E-07	8.986E-08	7.552E-08
NW	6.075E-06	2.103E-06	1.138E-06	7.358E-07	4.022E-07	2.625E-07	1.888E-07	1.443E-07	1.151E-07	9.466E-08	7.969E-08
NNW	5.151E-06	1.782E-06	9.742E-07	6.333E-07	3.473E-07	2.271E-07	1.636E-07	1.252E-07	9.994E-08	8.224E-08	6.928E-08
N	1.309E-05	4.559E-06	2.505E-06	1.631E-06	8.925E-07	5.826E-07	4.190E-07	3.203E-07	2.554E-07	2.100E-07	1.768E-07
NNE	1.672E-05	5.760E-06	3.153E-06	2.053E-06	1.125E-06	7.347E-07	5.287E-07	4.044E-07	3.226E-07	2.654E-07	2.234E-07
NE	1.364E-05	4.708E-06	2.573E-06	1.674E-06	9.190E-07	6.013E-07	4.333E-07	3.317E-07	2.649E-07	2.180E-07	1.837E-07
ENE	8.552E-06	2.860E-06	1.559E-06	1.019E-06	5.660E-07	3.734E-07	2.707E-07	2.083E-07	1.670E-07	1.380E-07	1.166E-07
E	1.671E-05	5.360E-06	2.906E-06	1.909E-06	1.079E-06	7.206E-07	5.273E-07	4.088E-07	3.298E-07	2.739E-07	2.325E-07
ESE	2.570E-05	7.976E-06	4.162E-06	2.690E-06	1.545E-06	1.045E-06	7.722E-07	6.033E-07	4.899E-07	4.091E-07	3.491E-07
SE	1.826E-05	5.713E-06	2.938E-06	1.876E-06	1.069E-06	7.203E-07	5.306E-07	4.137E-07	3.353E-07	2.796E-07	2.383E-07
SSE	9.423E-06	3.157E-06	1.657E-06	1.057E-06	5.790E-07	3.789E-07	2.731E-07	2.092E-07	1.671E-07	1.376E-07	1.160E-07

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	8.824E-08	4.788E-08	3.104E-08	1.684E-08	1.090E-08	7.753E-09	5.854E-09	4.605E-09	3.732E-09	3.094E-09	2.612E-09
SSW	7.080E-08	3.847E-08	2.496E-08	1.354E-08	8.750E-09	6.215E-09	4.685E-09	3.680E-09	2.977E-09	2.464E-09	2.077E-09
SW	6.393E-08	3.483E-08	2.264E-08	1.231E-08	7.970E-09	5.666E-09	4.274E-09	3.357E-09	2.716E-09	2.248E-09	1.894E-09
WSW	5.983E-08	3.268E-08	2.128E-08	1.160E-08	7.521E-09	5.353E-09	4.040E-09	3.175E-09	2.569E-09	2.127E-09	1.792E-09
W	7.492E-08	4.132E-08	2.709E-08	1.492E-08	9.740E-09	6.971E-09	5.285E-09	4.169E-09	3.385E-09	2.809E-09	2.373E-09
WNW	6.468E-08	3.572E-08	2.345E-08	1.295E-08	8.492E-09	6.099E-09	4.638E-09	3.669E-09	2.986E-09	2.485E-09	2.103E-09
NW	6.834E-08	3.789E-08	2.494E-08	1.382E-08	9.062E-09	6.510E-09	4.952E-09	3.917E-09	3.189E-09	2.653E-09	2.246E-09
NNW	5.944E-08	3.300E-08	2.174E-08	1.203E-08	7.877E-09	5.646E-09	4.284E-09	3.381E-09	2.746E-09	2.280E-09	1.925E-09
N	1.516E-07	8.395E-08	5.519E-08	3.047E-08	1.992E-08	1.426E-08	1.081E-08	8.529E-09	6.923E-09	5.744E-09	4.849E-09
NNE	1.916E-07	1.063E-07	6.999E-08	3.874E-08	2.537E-08	1.820E-08	1.382E-08	1.092E-08	8.878E-09	7.377E-09	6.237E-09
NE	1.576E-07	8.759E-08	5.773E-08	3.201E-08	2.100E-08	1.508E-08	1.146E-08	9.064E-09	7.375E-09	6.134E-09	5.190E-09
ENE	1.004E-07	5.635E-08	3.741E-08	2.093E-08	1.380E-08	9.941E-09	7.575E-09	5.999E-09	4.886E-09	4.065E-09	3.440E-09
E	2.009E-07	1.144E-07	7.670E-08	4.347E-08	2.891E-08	2.096E-08	1.605E-08	1.276E-08	1.042E-08	8.692E-09	7.371E-09
ESE	3.029E-07	1.754E-07	1.189E-07	6.846E-08	4.600E-08	3.362E-08	2.590E-08	2.069E-08	1.698E-08	1.421E-08	1.209E-08
SE	2.065E-07	1.193E-07	8.072E-08	4.639E-08	3.115E-08	2.276E-08	1.753E-08	1.400E-08	1.149E-08	9.618E-09	8.181E-09
SSE	9.963E-08	5.557E-08	3.674E-08	2.049E-08	1.351E-08	9.741E-09	7.431E-09	5.893E-09	4.806E-09	4.005E-09	3.394E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT (METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER (METERS)	0.00	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY (METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
		HEAT EMISSION RATE	(CAL/SEC)	0.0
		HEAT EMISSION RATE	(CAL/SEC)	0.0

0ALL GROUND LEVEL RELEASES.

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-7 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 2.260 Day Decay, Undepleted (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
2.260 DAY DECAY, UNDEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.354E-05	3.920E-06	1.922E-06	1.181E-06	6.070E-07	3.828E-07	2.690E-07	2.022E-07	1.591E-07	1.293E-07	1.079E-07
SSW	1.071E-05	3.111E-06	1.529E-06	9.401E-07	4.840E-07	3.056E-07	2.150E-07	1.617E-07	1.273E-07	1.036E-07	8.644E-08
SW	9.627E-06	2.800E-06	1.376E-06	8.459E-07	4.358E-07	2.754E-07	1.939E-07	1.460E-07	1.150E-07	9.365E-08	7.819E-08
WSW	9.038E-06	2.625E-06	1.288E-06	7.916E-07	4.079E-07	2.580E-07	1.817E-07	1.369E-07	1.079E-07	8.792E-08	7.343E-08
W	1.130E-05	3.275E-06	1.602E-06	9.845E-07	5.087E-07	3.226E-07	2.279E-07	1.721E-07	1.360E-07	1.110E-07	9.290E-08
WNW	9.788E-06	2.834E-06	1.385E-06	8.494E-07	4.379E-07	2.774E-07	1.959E-07	1.479E-07	1.168E-07	9.538E-08	7.982E-08
NW	9.995E-06	2.919E-06	1.433E-06	8.807E-07	4.558E-07	2.897E-07	2.051E-07	1.552E-07	1.229E-07	1.005E-07	8.422E-08
NNW	8.554E-06	2.503E-06	1.231E-06	7.563E-07	3.920E-07	2.495E-07	1.769E-07	1.340E-07	1.061E-07	8.686E-08	7.284E-08
N	2.175E-05	6.376E-06	3.141E-06	1.929E-06	9.987E-07	6.351E-07	4.498E-07	3.405E-07	2.695E-07	2.204E-07	1.848E-07
NNE	2.766E-05	8.092E-06	3.979E-06	2.444E-06	1.265E-06	8.048E-07	5.701E-07	4.316E-07	3.418E-07	2.796E-07	2.344E-07
NE	2.268E-05	6.646E-06	3.269E-06	2.009E-06	1.042E-06	6.630E-07	4.700E-07	3.561E-07	2.821E-07	2.309E-07	1.936E-07
ENE	1.435E-05	4.199E-06	2.058E-06	1.266E-06	6.589E-07	4.211E-07	2.996E-07	2.277E-07	1.809E-07	1.484E-07	1.247E-07
E	2.847E-05	8.328E-06	4.066E-06	2.505E-06	1.311E-06	8.421E-07	6.021E-07	4.595E-07	3.665E-07	3.017E-07	2.544E-07
ESE	4.386E-05	1.274E-05	6.169E-06	3.807E-06	2.002E-06	1.293E-06	9.289E-07	7.118E-07	5.698E-07	4.706E-07	3.980E-07
SE	3.064E-05	8.845E-06	4.271E-06	2.633E-06	1.382E-06	8.910E-07	6.389E-07	4.889E-07	3.908E-07	3.225E-07	2.725E-07
SSE	1.520E-05	4.380E-06	2.131E-06	1.309E-06	6.779E-07	4.312E-07	3.055E-07	2.313E-07	1.833E-07	1.500E-07	1.258E-07

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	9.173E-08	4.938E-08	3.188E-08	1.722E-08	1.112E-08	7.895E-09	5.954E-09	4.679E-09	3.790E-09	3.140E-09	2.649E-09
SSW	7.355E-08	3.964E-08	2.561E-08	1.383E-08	8.917E-09	6.323E-09	4.761E-09	3.736E-09	3.020E-09	2.499E-09	2.105E-09
SW	6.657E-08	3.596E-08	2.327E-08	1.259E-08	8.130E-09	5.770E-09	4.346E-09	3.411E-09	2.758E-09	2.281E-09	1.921E-09
WSW	6.254E-08	3.385E-08	2.194E-08	1.190E-08	7.690E-09	5.463E-09	4.117E-09	3.232E-09	2.614E-09	2.162E-09	1.820E-09
W	7.927E-08	4.324E-08	2.818E-08	1.542E-08	1.003E-08	7.162E-09	5.420E-09	4.270E-09	3.463E-09	2.871E-09	2.423E-09
WNW	6.813E-08	3.722E-08	2.429E-08	1.334E-08	8.713E-09	6.243E-09	4.739E-09	3.744E-09	3.044E-09	2.531E-09	2.141E-09
NW	7.197E-08	3.946E-08	2.583E-08	1.421E-08	9.290E-09	6.658E-09	5.055E-09	3.994E-09	3.248E-09	2.700E-09	2.284E-09
NNW	6.227E-08	3.420E-08	2.239E-08	1.232E-08	8.038E-09	5.749E-09	4.356E-09	3.434E-09	2.786E-09	2.311E-09	1.950E-09
N	1.579E-07	8.654E-08	5.658E-08	3.106E-08	2.024E-08	1.446E-08	1.095E-08	8.628E-09	6.998E-09	5.803E-09	4.896E-09
NNE	2.003E-07	1.099E-07	7.195E-08	3.958E-08	2.584E-08	1.849E-08	1.402E-08	1.107E-08	8.989E-09	7.464E-09	6.306E-09
NE	1.655E-07	9.096E-08	5.959E-08	3.283E-08	2.146E-08	1.537E-08	1.167E-08	9.215E-09	7.491E-09	6.225E-09	5.263E-09
ENE	1.069E-07	5.919E-08	3.900E-08	2.164E-08	1.420E-08	1.020E-08	7.760E-09	6.135E-09	4.990E-09	4.148E-09	3.507E-09
E	2.185E-07	1.223E-07	8.122E-08	4.555E-08	3.011E-08	2.175E-08	1.660E-08	1.317E-08	1.074E-08	8.946E-09	7.577E-09
ESE	3.428E-07	1.940E-07	1.299E-07	7.367E-08	4.910E-08	3.568E-08	2.738E-08	2.181E-08	1.785E-08	1.491E-08	1.266E-08
SE	2.345E-07	1.324E-07	8.849E-08	5.012E-08	3.338E-08	2.425E-08	1.860E-08	1.481E-08	1.212E-08	1.012E-08	8.597E-09
SSE	1.076E-07	5.919E-08	3.885E-08	2.148E-08	1.410E-08	1.013E-08	7.711E-09	6.103E-09	4.970E-09	4.136E-09	3.501E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	0.00	BUILDING HEIGHT	(METERS)	0.0
EXIT VELOCITY	(METERS)	0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	0.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

Note: Directions are True North.

Table 2.7-8 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, 2.260 Day Decay, Undepleted (Sheet 1 of 2)

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
   2.260 DAY DECAY,  UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT
                                            SEGMENT BOUNDARIES IN MILES FROM THE SITE
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DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	7.017E-08	8.088E-08	7.277E-08	5.882E-08	4.758E-08	2.778E-08	1.195E-08	5.928E-09	3.640E-09	2.496E-09
SSW	3.618E-08	5.164E-08	5.100E-08	4.298E-08	3.561E-08	2.141E-08	9.457E-09	4.733E-09	2.909E-09	1.993E-09
SW	2.751E-08	4.189E-08	4.270E-08	3.657E-08	3.060E-08	1.867E-08	8.374E-09	4.229E-09	2.610E-09	1.791E-09
WSW	2.585E-08	3.598E-08	3.619E-08	3.130E-08	2.646E-08	1.645E-08	7.534E-09	3.850E-09	2.388E-09	1.643E-09
W	3.133E-08	4.164E-08	4.151E-08	3.585E-08	3.035E-08	1.902E-08	8.861E-09	4.609E-09	2.895E-09	2.010E-09
WNW	3.747E-08	4.329E-08	4.105E-08	3.463E-08	2.888E-08	1.776E-08	8.173E-09	4.258E-09	2.685E-09	1.873E-09
NW	2.236E-08	3.730E-08	4.054E-08	3.566E-08	3.026E-08	1.889E-08	8.789E-09	4.591E-09	2.898E-09	2.021E-09
NNW	1.654E-08	2.629E-08	3.077E-08	2.836E-08	2.476E-08	1.606E-08	7.728E-09	4.085E-09	2.581E-09	1.797E-09
N	4.342E-08	7.044E-08	8.183E-08	7.515E-08	6.549E-08	4.237E-08	2.034E-08	1.073E-08	6.772E-09	4.709E-09
NNE	7.784E-08	1.015E-07	1.081E-07	9.636E-08	8.284E-08	5.298E-08	2.530E-08	1.339E-08	8.484E-09	5.923E-09
NE	5.515E-08	8.002E-08	8.665E-08	7.744E-08	6.662E-08	4.257E-08	2.032E-08	1.076E-08	6.822E-09	4.770E-09
ENE	3.133E-08	4.132E-08	4.518E-08	4.116E-08	3.598E-08	2.370E-08	1.176E-08	6.390E-09	4.109E-09	2.897E-09
E	3.013E-08	4.869E-08	6.018E-08	5.855E-08	5.335E-08	3.748E-08	2.000E-08	1.139E-08	7.511E-09	5.381E-09
ESE	4.534E-08	5.969E-08	6.796E-08	6.429E-08	5.793E-08	4.068E-08	2.220E-08	1.306E-08	8.835E-09	6.458E-09
SE	6.237E-08	5.830E-08	5.637E-08	4.975E-08	4.312E-08	2.871E-08	1.487E-08	8.527E-09	5.716E-09	4.161E-09
SSE	6.756E-08	6.563E-08	5.814E-08	4.775E-08	3.928E-08	2.381E-08	1.086E-08	5.662E-09	3.588E-09	2.515E-09

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
   2.260 DAY DECAY,  UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT
                                            SEGMENT BOUNDARIES IN MILES FROM THE SITE
```

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	5.236E-08	6.140E-08	6.046E-08	5.155E-08	4.292E-08	2.585E-08	1.139E-08	5.699E-09	3.509E-09	2.410E-09
SSW	2.615E-08	3.818E-08	4.164E-08	3.720E-08	3.180E-08	1.977E-08	8.964E-09	4.532E-09	2.796E-09	1.919E-09
SW	1.998E-08	3.072E-08	3.450E-08	3.135E-08	2.708E-08	1.711E-08	7.888E-09	4.028E-09	2.497E-09	1.718E-09
WSW	1.937E-08	2.672E-08	2.932E-08	2.685E-08	2.342E-08	1.505E-08	7.069E-09	3.650E-09	2.273E-09	1.568E-09
W	2.426E-08	3.116E-08	3.351E-08	3.049E-08	2.656E-08	1.716E-08	8.185E-09	4.298E-09	2.710E-09	1.886E-09
WNW	3.049E-08	3.262E-08	3.229E-08	2.857E-08	2.456E-08	1.570E-08	7.482E-09	3.964E-09	2.518E-09	1.764E-09
NW	1.659E-08	2.517E-08	2.981E-08	2.810E-08	2.485E-08	1.634E-08	7.960E-09	4.251E-09	2.708E-09	1.900E-09
NNW	1.289E-08	1.662E-08	2.141E-08	2.148E-08	1.972E-08	1.362E-08	6.932E-09	3.767E-09	2.409E-09	1.690E-09
N	3.317E-08	4.418E-08	5.661E-08	5.666E-08	5.197E-08	3.588E-08	1.825E-08	9.919E-09	6.344E-09	4.448E-09
NNE	6.023E-08	6.752E-08	7.724E-08	7.386E-08	6.630E-08	4.488E-08	2.261E-08	1.231E-08	7.902E-09	5.562E-09
NE	4.070E-08	5.209E-08	6.160E-08	5.930E-08	5.333E-08	3.608E-08	1.814E-08	9.863E-09	6.333E-09	4.461E-09
ENE	2.386E-08	2.657E-08	3.126E-08	3.056E-08	2.789E-08	1.948E-08	1.022E-08	5.719E-09	3.731E-09	2.653E-09
E	2.250E-08	2.858E-08	3.826E-08	4.020E-08	3.843E-08	2.895E-08	1.651E-08	9.756E-09	6.551E-09	4.746E-09
ESE	3.516E-08	3.774E-08	4.512E-08	4.532E-08	4.242E-08	3.134E-08	1.785E-08	1.071E-08	7.318E-09	5.385E-09
SE	5.160E-08	4.257E-08	4.234E-08	3.907E-08	3.480E-08	2.383E-08	1.251E-08	7.170E-09	4.800E-09	3.494E-09
SSE	5.406E-08	5.056E-08	4.739E-08	4.073E-08	3.440E-08	2.146E-08	9.981E-09	5.228E-09	3.313E-09	2.322E-09

Note: Directions are True North.

Table 2.7-8 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, 2.260 Day Decay, Undepleted (Sheet 2 of 2)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
2.260 DAY DECAY, UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

DIRECTION FROM SITE	SEGMENT BOUNDARIES IN MILES FROM THE SITE .5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.669E-06	5.713E-07	2.557E-07	1.523E-07	1.038E-07	4.936E-08	1.735E-08	7.832E-09	4.629E-09	3.104E-09
SSW	1.318E-06	4.547E-07	2.043E-07	1.220E-07	8.326E-08	3.965E-08	1.395E-08	6.279E-09	3.699E-09	2.473E-09
SW	1.177E-06	4.072E-07	1.836E-07	1.099E-07	7.512E-08	3.588E-08	1.268E-08	5.723E-09	3.375E-09	2.256E-09
WSW	1.093E-06	3.785E-07	1.712E-07	1.026E-07	7.026E-08	3.365E-08	1.194E-08	5.406E-09	3.191E-09	2.134E-09
W	1.326E-06	4.616E-07	2.110E-07	1.275E-07	8.776E-08	4.246E-08	1.532E-08	7.035E-09	4.189E-09	2.818E-09
WNW	1.151E-06	4.000E-07	1.824E-07	1.100E-07	7.576E-08	3.670E-08	1.330E-08	6.152E-09	3.686E-09	2.492E-09
NW	1.174E-06	4.143E-07	1.907E-07	1.157E-07	7.992E-08	3.890E-08	1.418E-08	6.567E-09	3.935E-09	2.661E-09
NNW	1.002E-06	3.574E-07	1.652E-07	1.004E-07	6.947E-08	3.387E-08	1.234E-08	5.696E-09	3.397E-09	2.286E-09
N	2.573E-06	9.189E-07	4.231E-07	2.567E-07	1.773E-07	8.619E-08	3.127E-08	1.439E-08	8.570E-09	5.762E-09
NNE	3.243E-06	1.158E-06	5.339E-07	3.242E-07	2.241E-07	1.091E-07	3.974E-08	1.836E-08	1.097E-08	7.399E-09
NE	2.648E-06	9.457E-07	4.375E-07	2.661E-07	1.842E-07	8.988E-08	3.283E-08	1.521E-08	9.106E-09	6.152E-09
ENE	1.608E-06	5.811E-07	2.731E-07	1.678E-07	1.169E-07	5.771E-08	2.142E-08	1.002E-08	6.025E-09	4.077E-09
E	3.008E-06	1.104E-06	5.315E-07	3.310E-07	2.330E-07	1.169E-07	4.438E-08	2.111E-08	1.281E-08	8.715E-09
ESE	4.355E-06	1.577E-06	7.774E-07	4.915E-07	3.497E-07	1.786E-07	6.969E-08	3.383E-08	2.076E-08	1.424E-08
SE	3.083E-06	1.094E-06	5.344E-07	3.365E-07	2.388E-07	1.215E-07	4.725E-08	2.290E-08	1.405E-08	9.640E-09
SSE	1.724E-06	5.963E-07	2.757E-07	1.679E-07	1.164E-07	5.699E-08	2.100E-08	9.822E-09	5.918E-09	4.016E-09

Note: The results on the top half of this page are applicable to releases from the RW-VS.

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
2.260 DAY DECAY, UNDEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

DIRECTION FROM SITE	SEGMENT BOUNDARIES IN MILES FROM THE SITE .5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	2.037E-06	6.349E-07	2.726E-07	1.601E-07	1.083E-07	5.101E-08	1.776E-08	7.978E-09	4.705E-09	3.151E-09
SSW	1.619E-06	5.061E-07	2.179E-07	1.281E-07	8.675E-08	4.094E-08	1.427E-08	6.390E-09	3.756E-09	2.507E-09
SW	1.457E-06	4.556E-07	1.965E-07	1.157E-07	7.847E-08	3.712E-08	1.298E-08	5.830E-09	3.430E-09	2.289E-09
WSW	1.365E-06	4.265E-07	1.841E-07	1.086E-07	7.369E-08	3.493E-08	1.226E-08	5.519E-09	3.249E-09	2.169E-09
W	1.699E-06	5.317E-07	2.308E-07	1.368E-07	9.322E-08	4.455E-08	1.586E-08	7.230E-09	4.291E-09	2.881E-09
WNW	1.469E-06	4.580E-07	1.984E-07	1.175E-07	8.010E-08	3.834E-08	1.372E-08	6.300E-09	3.762E-09	2.538E-09
NW	1.518E-06	4.764E-07	2.077E-07	1.236E-07	8.450E-08	4.063E-08	1.461E-08	6.719E-09	4.013E-09	2.708E-09
NNW	1.303E-06	4.096E-07	1.791E-07	1.067E-07	7.308E-08	3.519E-08	1.266E-08	5.802E-09	3.450E-09	2.318E-09
N	3.321E-06	1.044E-06	4.555E-07	2.711E-07	1.854E-07	8.907E-08	3.192E-08	1.460E-08	8.671E-09	5.821E-09
NNE	4.211E-06	1.323E-06	5.773E-07	3.437E-07	2.351E-07	1.131E-07	4.066E-08	1.866E-08	1.112E-08	7.487E-09
NE	3.460E-06	1.088E-06	4.759E-07	2.837E-07	1.943E-07	9.359E-08	3.372E-08	1.551E-08	9.259E-09	6.243E-09
ENE	2.182E-06	6.882E-07	3.032E-07	1.819E-07	1.251E-07	6.081E-08	2.219E-08	1.029E-08	6.163E-09	4.160E-09
E	4.319E-06	1.368E-06	6.091E-07	3.684E-07	2.551E-07	1.254E-07	4.661E-08	2.192E-08	1.323E-08	8.971E-09
ESE	6.580E-06	2.088E-06	9.392E-07	5.726E-07	3.991E-07	1.986E-07	7.524E-08	3.594E-08	2.189E-08	1.495E-08
SE	4.560E-06	1.442E-06	6.461E-07	3.928E-07	2.732E-07	1.356E-07	5.120E-08	2.442E-08	1.487E-08	1.015E-08
SSE	2.265E-06	7.085E-07	3.094E-07	1.843E-07	1.262E-07	6.090E-08	2.206E-08	1.022E-08	6.131E-09	4.148E-09

Note: Directions are True North.

Table 2.7-9 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 8.000 Day Decay, Depleted (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
8.000 DAY DECAY, DEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.169E-07	6.545E-08	6.291E-08	7.283E-08	8.268E-08	7.920E-08	7.173E-08	6.394E-08	5.687E-08	5.072E-08	4.545E-08
SSW	5.238E-08	2.982E-08	3.120E-08	4.080E-08	5.294E-08	5.395E-08	5.066E-08	4.627E-08	4.190E-08	3.788E-08	3.432E-08
SW	3.959E-08	2.234E-08	2.331E-08	3.159E-08	4.291E-08	4.468E-08	4.253E-08	3.922E-08	3.578E-08	3.254E-08	2.962E-08
WSW	3.339E-08	2.178E-08	2.287E-08	2.867E-08	3.659E-08	3.771E-08	3.598E-08	3.337E-08	3.064E-08	2.804E-08	2.566E-08
W	4.527E-08	2.876E-08	2.756E-08	3.364E-08	4.231E-08	4.331E-08	4.121E-08	3.820E-08	3.507E-08	3.212E-08	2.944E-08
WNW	4.579E-08	3.709E-08	3.445E-08	3.789E-08	4.373E-08	4.352E-08	4.076E-08	3.734E-08	3.397E-08	3.089E-08	2.815E-08
NW	2.863E-08	1.976E-08	1.866E-08	2.553E-08	3.800E-08	4.165E-08	4.081E-08	3.833E-08	3.542E-08	3.255E-08	2.988E-08
NNW	3.052E-08	1.970E-08	1.349E-08	1.662E-08	2.634E-08	3.058E-08	3.118E-08	3.014E-08	2.846E-08	2.660E-08	2.476E-08
N	8.413E-08	4.846E-08	3.569E-08	4.497E-08	7.066E-08	8.158E-08	8.291E-08	7.999E-08	7.544E-08	7.044E-08	6.552E-08
NNE	1.470E-07	8.704E-08	6.779E-08	7.656E-08	1.019E-07	1.103E-07	1.087E-07	1.030E-07	9.602E-08	8.894E-08	8.225E-08
NE	1.043E-07	5.532E-08	4.706E-08	5.765E-08	8.057E-08	8.823E-08	8.722E-08	8.275E-08	7.718E-08	7.150E-08	6.613E-08
ENE	7.254E-08	3.586E-08	2.692E-08	3.048E-08	4.127E-08	4.549E-08	4.551E-08	4.368E-08	4.116E-08	3.849E-08	3.589E-08
E	8.066E-08	3.577E-08	2.455E-08	2.993E-08	4.796E-08	5.771E-08	6.099E-08	6.087E-08	5.910E-08	5.659E-08	5.382E-08
ESE	1.108E-07	5.409E-08	3.891E-08	4.291E-08	5.893E-08	6.672E-08	6.843E-08	6.712E-08	6.449E-08	6.134E-08	5.808E-08
SE	1.496E-07	8.197E-08	5.625E-08	5.319E-08	5.771E-08	5.823E-08	5.599E-08	5.268E-08	4.912E-08	4.566E-08	4.245E-08
SSE	1.164E-07	7.604E-08	6.198E-08	6.287E-08	6.605E-08	6.277E-08	5.726E-08	5.159E-08	4.639E-08	4.183E-08	3.786E-08

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	4.095E-08	2.620E-08	1.841E-08	1.081E-08	7.278E-09	5.311E-09	4.087E-09	3.265E-09	2.682E-09	2.259E-09	1.926E-09
SSW	3.119E-08	2.052E-08	1.463E-08	8.732E-09	5.932E-09	4.354E-09	3.365E-09	2.698E-09	2.223E-09	1.877E-09	1.603E-09
SW	2.704E-08	1.805E-08	1.299E-08	7.841E-09	5.368E-09	3.963E-09	3.077E-09	2.477E-09	2.047E-09	1.733E-09	1.484E-09
WSW	2.354E-08	1.599E-08	1.163E-08	7.113E-09	4.910E-09	3.646E-09	2.843E-09	2.296E-09	1.904E-09	1.615E-09	1.387E-09
W	2.705E-08	1.853E-08	1.359E-08	8.425E-09	5.883E-09	4.411E-09	3.469E-09	2.822E-09	2.355E-09	2.008E-09	1.733E-09
WNW	2.575E-08	1.744E-08	1.274E-08	7.897E-09	5.533E-09	4.162E-09	3.281E-09	2.676E-09	2.237E-09	1.909E-09	1.650E-09
NW	2.748E-08	1.888E-08	1.390E-08	8.694E-09	6.119E-09	4.619E-09	3.654E-09	2.987E-09	2.503E-09	2.141E-09	1.855E-09
NNW	2.303E-08	1.640E-08	1.232E-08	7.868E-09	5.597E-09	4.253E-09	3.379E-09	2.772E-09	2.328E-09	1.994E-09	1.731E-09
N	6.091E-08	4.330E-08	3.248E-08	2.073E-08	1.473E-08	1.118E-08	8.879E-09	7.278E-09	6.109E-09	5.228E-09	4.535E-09
NNE	7.613E-08	5.356E-08	4.003E-08	2.549E-08	1.812E-08	1.377E-08	1.094E-08	8.976E-09	7.541E-09	6.459E-09	5.607E-09
NE	6.120E-08	4.301E-08	3.212E-08	2.044E-08	1.453E-08	1.104E-08	8.777E-09	7.205E-09	6.055E-09	5.190E-09	4.507E-09
ENE	3.347E-08	2.420E-08	1.843E-08	1.205E-08	8.718E-09	6.715E-09	5.394E-09	4.466E-09	3.781E-09	3.260E-09	2.847E-09
E	5.102E-08	3.905E-08	3.082E-08	2.107E-08	1.570E-08	1.234E-08	1.008E-08	8.455E-09	7.237E-09	6.296E-09	5.546E-09
ESE	5.492E-08	4.201E-08	3.340E-08	2.326E-08	1.764E-08	1.410E-08	1.167E-08	9.917E-09	8.583E-09	7.543E-09	6.705E-09
SE	3.955E-08	2.881E-08	2.225E-08	1.500E-08	1.118E-08	8.833E-09	7.260E-09	6.133E-09	5.288E-09	4.635E-09	4.109E-09
SSE	3.445E-08	2.295E-08	1.663E-08	1.024E-08	7.161E-09	5.388E-09	4.254E-09	3.476E-09	2.912E-09	2.492E-09	2.160E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	52.77	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	2.40	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	17.78	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):

VENT RELEASE MODE	WIND SPEED (METERS/SEC)	/	VENT RELEASE MODE	WIND SPEED (METERS/SEC) STABLE CONDITIONS	WIND SPEED (METERS/SEC) UNSTABLE/NEUTRAL CONDITIONS
ELEVATED	LESS THAN 3.556	/	ELEVATED	LESS THAN 3.556	LESS THAN 3.556
MIXED	BETWEEN 3.556 AND 17.780	/	MIXED	BETWEEN 3.556 AND 17.780	BETWEEN 3.556 AND 17.780
GROUND LEVEL	ABOVE 17.780	/	GROUND LEVEL	ABOVE 17.780	ABOVE 17.780

Note: Directions are True North.

Table 2.7-9 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 8.000 Day Decay, Depleted (Sheet 2 of 4)

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
   8.000 DAY DECAY,    DEPLETED
0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
   SECTOR         0.250     0.500     0.750     1.000     1.500     2.000     2.500     3.000     3.500     4.000     4.500
       S        1.101E-07 5.617E-08 4.555E-08 5.062E-08 6.141E-08 6.281E-08 5.953E-08 5.475E-08 4.978E-08 4.512E-08 4.092E-08
     SSW        4.985E-08 2.592E-08 2.194E-08 2.715E-08 3.807E-08 4.179E-08 4.128E-08 3.902E-08 3.619E-08 3.329E-08 3.055E-08
      SW        3.718E-08 1.972E-08 1.661E-08 2.101E-08 3.053E-08 3.420E-08 3.426E-08 3.272E-08 3.059E-08 2.832E-08 2.612E-08
     WSW        3.114E-08 1.900E-08 1.703E-08 1.990E-08 2.638E-08 2.900E-08 2.905E-08 2.788E-08 2.621E-08 2.440E-08 2.262E-08
       W        4.234E-08 2.592E-08 2.124E-08 2.392E-08 3.078E-08 3.333E-08 3.313E-08 3.167E-08 2.972E-08 2.765E-08 2.564E-08
     WNW        4.190E-08 3.296E-08 2.843E-08 2.882E-08 3.204E-08 3.284E-08 3.183E-08 2.999E-08 2.788E-08 2.579E-08 2.381E-08
      NW        2.576E-08 1.773E-08 1.442E-08 1.677E-08 2.457E-08 2.877E-08 2.981E-08 2.918E-08 2.779E-08 2.614E-08 2.443E-08
     NNW        2.752E-08 1.857E-08 1.118E-08 1.072E-08 1.568E-08 1.968E-08 2.151E-08 2.189E-08 2.146E-08 2.063E-08 1.963E-08
       N        7.467E-08 4.492E-08 2.905E-08 2.866E-08 4.172E-08 5.214E-08 5.688E-08 5.781E-08 5.665E-08 5.444E-08 5.177E-08
     NNE        1.305E-07 7.802E-08 5.413E-08 5.183E-08 6.470E-08 7.406E-08 7.707E-08 7.614E-08 7.325E-08 6.950E-08 6.549E-08
      NE        9.437E-08 4.883E-08 3.575E-08 3.698E-08 5.000E-08 5.864E-08 6.155E-08 6.105E-08 5.883E-08 5.588E-08 5.268E-08
     ENE        6.483E-08 3.235E-08 2.101E-08 1.989E-08 2.530E-08 2.953E-08 3.122E-08 3.125E-08 3.039E-08 2.912E-08 2.767E-08
       E        7.116E-08 3.261E-08 1.936E-08 1.828E-08 2.654E-08 3.415E-08 3.840E-08 4.015E-08 4.037E-08 3.972E-08 3.859E-08
     ESE        9.879E-08 4.878E-08 3.109E-08 2.861E-08 3.559E-08 4.190E-08 4.498E-08 4.575E-08 4.519E-08 4.391E-08 4.229E-08
      SE        1.322E-07 7.376E-08 4.693E-08 4.029E-08 4.085E-08 4.203E-08 4.170E-08 4.029E-08 3.833E-08 3.618E-08 3.402E-08
     SSE        1.058E-07 6.637E-08 4.921E-08 4.719E-08 4.978E-08 4.920E-08 4.648E-08 4.300E-08 3.944E-08 3.608E-08 3.302E-08
0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
   SECTOR         5.000     7.500    10.000    15.000    20.000    25.000    30.000    35.000    40.000    45.000    50.000
       S        3.721E-08 2.442E-08 1.734E-08 1.027E-08 6.938E-09 5.070E-09 3.903E-09 3.119E-09 2.563E-09 2.159E-09 1.840E-09
     SSW        2.805E-08 1.895E-08 1.368E-08 8.246E-09 5.626E-09 4.139E-09 3.203E-09 2.571E-09 2.119E-09 1.790E-09 1.530E-09
      SW        2.409E-08 1.653E-08 1.205E-08 7.354E-09 5.059E-09 3.746E-09 2.913E-09 2.348E-09 1.942E-09 1.645E-09 1.410E-09
     WSW        2.095E-08 1.461E-08 1.075E-08 6.638E-09 4.602E-09 3.426E-09 2.675E-09 2.163E-09 1.795E-09 1.524E-09 1.308E-09
       W        2.377E-08 1.668E-08 1.235E-08 7.727E-09 5.415E-09 4.068E-09 3.203E-09 2.608E-09 2.177E-09 1.858E-09 1.604E-09
     WNW        2.202E-08 1.539E-08 1.142E-08 7.193E-09 5.082E-09 3.841E-09 3.039E-09 2.484E-09 2.081E-09 1.779E-09 1.540E-09
      NW        2.279E-08 1.634E-08 1.229E-08 7.856E-09 5.592E-09 4.251E-09 3.378E-09 2.772E-09 2.329E-09 1.997E-09 1.734E-09
     NNW        1.858E-08 1.394E-08 1.074E-08 7.053E-09 5.091E-09 3.905E-09 3.123E-09 2.574E-09 2.171E-09 1.865E-09 1.623E-09
       N        4.900E-08 3.675E-08 2.833E-08 1.860E-08 1.343E-08 1.030E-08 8.235E-09 6.786E-09 5.721E-09 4.914E-09 4.276E-09
     NNE        6.156E-08 4.540E-08 3.477E-08 2.274E-08 1.641E-08 1.259E-08 1.007E-08 8.310E-09 7.013E-09 6.030E-09 5.251E-09
      NE        4.952E-08 3.648E-08 2.791E-08 1.822E-08 1.313E-08 1.007E-08 8.059E-09 6.647E-09 5.611E-09 4.826E-09 4.204E-09
     ENE        2.621E-08 1.989E-08 1.554E-08 1.045E-08 7.679E-09 5.976E-09 4.837E-09 4.028E-09 3.426E-09 2.966E-09 2.599E-09
       E        3.724E-08 3.017E-08 2.457E-08 1.740E-08 1.322E-08 1.054E-08 8.686E-09 7.341E-09 6.323E-09 5.529E-09 4.892E-09
     ESE        4.054E-08 3.231E-08 2.621E-08 1.862E-08 1.427E-08 1.148E-08 9.552E-09 8.144E-09 7.072E-09 6.234E-09 5.555E-09
      SE        3.198E-08 2.381E-08 1.850E-08 1.248E-08 9.274E-09 7.312E-09 5.997E-09 5.058E-09 4.357E-09 3.817E-09 3.382E-09
     SSE        3.030E-08 2.066E-08 1.510E-08 9.344E-09 6.535E-09 4.910E-09 3.871E-09 3.158E-09 2.642E-09 2.259E-09 1.955E-09
0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)   71.30                   REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    1.95                   BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)   17.78                   BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                        HEAT EMISSION RATE     (CAL/SEC)       0.0
0AT THE RELEASE HEIGHT:                             /  AT THE MEASURED WIND HEIGHT ( 10.0 METERS):
 VENT RELEASE MODE   WIND SPEED (METERS/SEC)      /  VENT RELEASE MODE   WIND SPEED (METERS/SEC)        WIND SPEED (METERS/SEC)
                                                    /                      STABLE CONDITIONS              UNSTABLE/NEUTRAL CONDITIONS
     ELEVATED        LESS THAN  3.556             /      ELEVATED        LESS THAN  3.556               LESS THAN  3.556
     MIXED           BETWEEN    3.556 AND 17.780 /      MIXED           BETWEEN    3.556 AND 17.780   BETWEEN    3.556 AND 17.780
     GROUND LEVEL    ABOVE     17.780             /      GROUND LEVEL    ABOVE     17.780               ABOVE     17.780
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Note: Directions are True North.

Table 2.7-9 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 8.000 Day Decay, Depleted (Sheet 3 of 4)

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1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0          RUN DATE:  7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
   8.000 DAY DECAY,    DEPLETED
0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
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SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	8.096E-06	2.770E-06	1.441E-06	9.047E-07	4.714E-07	2.962E-07	2.064E-07	1.535E-07	1.195E-07	9.613E-08	7.933E-08
SSW	6.331E-06	2.178E-06	1.140E-06	7.185E-07	3.756E-07	2.365E-07	1.650E-07	1.229E-07	9.576E-08	7.711E-08	6.368E-08
SW	5.670E-06	1.942E-06	1.018E-06	6.424E-07	3.366E-07	2.124E-07	1.484E-07	1.107E-07	8.631E-08	6.958E-08	5.751E-08
WSW	5.324E-06	1.806E-06	9.450E-07	5.965E-07	3.132E-07	1.979E-07	1.384E-07	1.033E-07	8.069E-08	6.509E-08	5.385E-08
W	6.627E-06	2.197E-06	1.145E-06	7.231E-07	3.824E-07	2.430E-07	1.708E-07	1.280E-07	1.003E-07	8.114E-08	6.730E-08
WNW	5.769E-06	1.903E-06	9.940E-07	6.277E-07	3.311E-07	2.101E-07	1.475E-07	1.105E-07	8.654E-08	7.001E-08	5.806E-08
NW	5.755E-06	1.924E-06	1.017E-06	6.464E-07	3.434E-07	2.189E-07	1.543E-07	1.159E-07	9.097E-08	7.373E-08	6.125E-08
NNW	4.880E-06	1.630E-06	8.708E-07	5.566E-07	2.968E-07	1.896E-07	1.339E-07	1.007E-07	7.910E-08	6.417E-08	5.335E-08
N	1.240E-05	4.172E-06	2.239E-06	1.433E-06	7.625E-07	4.863E-07	3.428E-07	2.575E-07	2.021E-07	1.638E-07	1.361E-07
NNE	1.584E-05	5.270E-06	2.817E-06	1.804E-06	9.605E-07	6.130E-07	4.324E-07	3.249E-07	2.551E-07	2.069E-07	1.719E-07
NE	1.292E-05	4.307E-06	2.299E-06	1.471E-06	7.849E-07	5.017E-07	3.543E-07	2.665E-07	2.094E-07	1.699E-07	1.413E-07
ENE	8.102E-06	2.617E-06	1.394E-06	8.958E-07	4.837E-07	3.118E-07	2.216E-07	1.676E-07	1.323E-07	1.077E-07	8.985E-08
E	1.583E-05	4.905E-06	2.598E-06	1.679E-06	9.225E-07	6.021E-07	4.320E-07	3.291E-07	2.614E-07	2.140E-07	1.794E-07
ESE	2.435E-05	7.301E-06	3.722E-06	2.365E-06	1.321E-06	8.734E-07	6.328E-07	4.860E-07	3.886E-07	3.200E-07	2.695E-07
SE	1.730E-05	5.229E-06	2.627E-06	1.650E-06	9.144E-07	6.019E-07	4.348E-07	3.332E-07	2.659E-07	2.187E-07	1.840E-07
SSE	8.926E-06	2.888E-06	1.481E-06	9.287E-07	4.945E-07	3.161E-07	2.233E-07	1.681E-07	1.322E-07	1.073E-07	8.926E-08

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0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED)                 DISTANCE INMILES FROM THE SITE
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SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	6.679E-08	3.455E-08	2.151E-08	1.098E-08	6.780E-09	4.644E-09	3.396E-09	2.598E-09	2.054E-09	1.666E-09	1.378E-09
SSW	5.366E-08	2.781E-08	1.734E-08	8.857E-09	5.468E-09	3.743E-09	2.735E-09	2.091E-09	1.653E-09	1.340E-09	1.108E-09
SW	4.849E-08	2.521E-08	1.576E-08	8.078E-09	4.999E-09	3.429E-09	2.509E-09	1.921E-09	1.520E-09	1.233E-09	1.020E-09
WSW	4.544E-08	2.370E-08	1.485E-08	7.637E-09	4.739E-09	3.257E-09	2.388E-09	1.831E-09	1.450E-09	1.177E-09	9.751E-10
W	5.693E-08	2.998E-08	1.892E-08	9.834E-09	6.151E-09	4.254E-09	3.135E-09	2.413E-09	1.919E-09	1.563E-09	1.298E-09
WNW	4.911E-08	2.589E-08	1.635E-08	8.520E-09	5.346E-09	3.707E-09	2.737E-09	2.111E-09	1.681E-09	1.372E-09	1.141E-09
NW	5.188E-08	2.746E-08	1.739E-08	9.081E-09	5.699E-09	3.951E-09	2.917E-09	2.250E-09	1.791E-09	1.461E-09	1.215E-09
NNW	4.522E-08	2.399E-08	1.521E-08	7.956E-09	4.992E-09	3.459E-09	2.552E-09	1.967E-09	1.565E-09	1.276E-09	1.060E-09
N	1.153E-07	6.099E-08	3.860E-08	2.012E-08	1.260E-08	8.718E-09	6.425E-09	4.946E-09	3.931E-09	3.202E-09	2.659E-09
NNE	1.456E-07	7.716E-08	4.888E-08	2.553E-08	1.601E-08	1.109E-08	8.181E-09	6.305E-09	5.015E-09	4.088E-09	3.397E-09
NE	1.197E-07	6.354E-08	4.029E-08	2.108E-08	1.323E-08	9.173E-09	6.772E-09	5.222E-09	4.157E-09	3.390E-09	2.818E-09
ENE	7.639E-08	4.100E-08	2.621E-08	1.386E-08	8.764E-09	6.109E-09	4.530E-09	3.505E-09	2.798E-09	2.288E-09	1.906E-09
E	1.531E-07	8.343E-08	5.390E-08	2.891E-08	1.846E-08	1.296E-08	9.668E-09	7.517E-09	6.026E-09	4.944E-09	4.132E-09
ESE	2.311E-07	1.281E-07	8.375E-08	4.568E-08	2.950E-08	2.090E-08	1.570E-08	1.228E-08	9.898E-09	8.158E-09	6.845E-09
SE	1.576E-07	8.710E-08	5.684E-08	3.095E-08	1.998E-08	1.415E-08	1.063E-08	8.316E-09	6.701E-09	5.524E-09	4.636E-09
SSE	7.572E-08	4.035E-08	2.568E-08	1.353E-08	8.548E-09	5.960E-09	4.421E-09	3.423E-09	2.735E-09	2.238E-09	1.867E-09

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0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)    0.00                  REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    0.00                  BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)    0.00                  BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                       HEAT EMISSION RATE     (CAL/SEC)       0.0
0ALL GROUND LEVEL RELEASES.
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Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-9 Long-Term χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles, 8.000 Day Decay, Depleted (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
8.000 DAY DECAY, DEPLETED

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.283E-05	3.585E-06	1.717E-06	1.037E-06	5.179E-07	3.189E-07	2.196E-07	1.621E-07	1.255E-07	1.005E-07	8.270E-08
SSW	1.014E-05	2.846E-06	1.366E-06	8.256E-07	4.131E-07	2.547E-07	1.756E-07	1.297E-07	1.005E-07	8.060E-08	6.635E-08
SW	9.119E-06	2.562E-06	1.229E-06	7.430E-07	3.720E-07	2.296E-07	1.585E-07	1.172E-07	9.086E-08	7.292E-08	6.006E-08
WSW	8.561E-06	2.402E-06	1.151E-06	6.955E-07	3.484E-07	2.152E-07	1.486E-07	1.100E-07	8.532E-08	6.851E-08	5.647E-08
W	1.070E-05	2.996E-06	1.432E-06	8.651E-07	4.345E-07	2.692E-07	1.864E-07	1.383E-07	1.075E-07	8.654E-08	7.147E-08
WNW	9.272E-06	2.593E-06	1.238E-06	7.462E-07	3.739E-07	2.314E-07	1.601E-07	1.188E-07	9.236E-08	7.432E-08	6.137E-08
NW	9.468E-06	2.671E-06	1.281E-06	7.737E-07	3.892E-07	2.417E-07	1.677E-07	1.247E-07	9.713E-08	7.829E-08	6.475E-08
NNW	8.104E-06	2.291E-06	1.100E-06	6.647E-07	3.350E-07	2.083E-07	1.447E-07	1.077E-07	8.402E-08	6.778E-08	5.610E-08
N	2.060E-05	5.834E-06	2.807E-06	1.695E-06	8.533E-07	5.301E-07	3.680E-07	2.737E-07	2.133E-07	1.720E-07	1.422E-07
NNE	2.621E-05	7.404E-06	3.556E-06	2.147E-06	1.081E-06	6.716E-07	4.663E-07	3.468E-07	2.703E-07	2.179E-07	1.803E-07
NE	2.148E-05	6.081E-06	2.921E-06	1.766E-06	8.896E-07	5.532E-07	3.844E-07	2.861E-07	2.231E-07	1.800E-07	1.489E-07
ENE	1.360E-05	3.842E-06	1.840E-06	1.113E-06	5.631E-07	3.516E-07	2.452E-07	1.831E-07	1.432E-07	1.159E-07	9.612E-08
E	2.697E-05	7.622E-06	3.635E-06	2.203E-06	1.121E-06	7.037E-07	4.932E-07	3.700E-07	2.905E-07	2.358E-07	1.963E-07
ESE	4.156E-05	1.166E-05	5.517E-06	3.348E-06	1.713E-06	1.081E-06	7.614E-07	5.735E-07	4.520E-07	3.682E-07	3.074E-07
SE	2.904E-05	8.096E-06	3.820E-06	2.316E-06	1.182E-06	7.447E-07	5.236E-07	3.938E-07	3.100E-07	2.523E-07	2.104E-07
SSE	1.440E-05	4.007E-06	1.904E-06	1.150E-06	5.791E-07	3.598E-07	2.499E-07	1.859E-07	1.450E-07	1.170E-07	9.681E-08

0ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) DISTANCE INMILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	6.945E-08	3.564E-08	2.211E-08	1.123E-08	6.921E-09	4.733E-09	3.457E-09	2.643E-09	2.088E-09	1.693E-09	1.400E-09
SSW	5.575E-08	2.866E-08	1.780E-08	9.052E-09	5.575E-09	3.810E-09	2.781E-09	2.125E-09	1.678E-09	1.359E-09	1.123E-09
SW	5.051E-08	2.604E-08	1.620E-08	8.266E-09	5.102E-09	3.494E-09	2.554E-09	1.953E-09	1.544E-09	1.252E-09	1.035E-09
WSW	4.751E-08	2.456E-08	1.531E-08	7.834E-09	4.848E-09	3.326E-09	2.435E-09	1.865E-09	1.476E-09	1.198E-09	9.915E-10
W	6.025E-08	3.139E-08	1.969E-08	1.017E-08	6.339E-09	4.373E-09	3.217E-09	2.474E-09	1.965E-09	1.599E-09	1.327E-09
WNW	5.174E-08	2.699E-08	1.695E-08	8.777E-09	5.488E-09	3.797E-09	2.799E-09	2.156E-09	1.715E-09	1.399E-09	1.162E-09
NW	5.465E-08	2.861E-08	1.801E-08	9.346E-09	5.845E-09	4.043E-09	2.980E-09	2.296E-09	1.826E-09	1.488E-09	1.237E-09
NNW	4.738E-08	2.487E-08	1.568E-08	8.147E-09	5.095E-09	3.523E-09	2.596E-09	1.998E-09	1.588E-09	1.294E-09	1.074E-09
N	1.201E-07	6.288E-08	3.957E-08	2.052E-08	1.281E-08	8.843E-09	6.508E-09	5.005E-09	3.975E-09	3.235E-09	2.685E-09
NNE	1.522E-07	7.978E-08	5.025E-08	2.609E-08	1.630E-08	1.127E-08	8.303E-09	6.391E-09	5.080E-09	4.138E-09	3.436E-09
NE	1.258E-07	6.599E-08	4.160E-08	2.162E-08	1.352E-08	9.356E-09	6.896E-09	5.311E-09	4.223E-09	3.442E-09	2.860E-09
ENE	8.136E-08	4.307E-08	2.733E-08	1.434E-08	9.026E-09	6.274E-09	4.642E-09	3.586E-09	2.860E-09	2.336E-09	1.944E-09
E	1.666E-07	8.921E-08	5.708E-08	3.030E-08	1.923E-08	1.345E-08	1.001E-08	7.764E-09	6.213E-09	5.091E-09	4.250E-09
ESE	2.617E-07	1.417E-07	9.148E-08	4.918E-08	3.150E-08	2.220E-08	1.661E-08	1.295E-08	1.041E-08	8.564E-09	7.173E-09
SE	1.790E-07	9.672E-08	6.233E-08	3.346E-08	2.142E-08	1.509E-08	1.129E-08	8.802E-09	7.075E-09	5.820E-09	4.875E-09
SSE	8.178E-08	4.300E-08	2.717E-08	1.420E-08	8.929E-09	6.206E-09	4.593E-09	3.550E-09	2.832E-09	2.315E-09	1.928E-09

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS) 0.00	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS) 0.00	BUILDING HEIGHT	(METERS)	0.0
EXIT VELOCITY	(METERS) 0.00	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	0.0
		HEAT EMISSION RATE	(CAL/SEC)	0.0

Note: Directions are True North.

Table 2.7-10 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, 8.000 Day Decay, Depleted (Sheet 1 of 2)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
8.000 DAY DECAY, DEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

SEGMENT BOUNDARIES IN MILES FROM THE SITE

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	6.788E-08	7.894E-08	7.061E-08	5.655E-08	4.535E-08	2.602E-08	1.093E-08	5.346E-09	3.278E-09	2.261E-09
SSW	3.516E-08	5.069E-08	4.978E-08	4.162E-08	3.421E-08	2.027E-08	8.799E-09	4.379E-09	2.708E-09	1.878E-09
SW	2.678E-08	4.118E-08	4.178E-08	3.553E-08	2.953E-08	1.780E-08	7.886E-09	3.983E-09	2.485E-09	1.734E-09
WSW	2.521E-08	3.533E-08	3.540E-08	3.043E-08	2.558E-08	1.573E-08	7.138E-09	3.662E-09	2.303E-09	1.616E-09
W	3.053E-08	4.083E-08	4.056E-08	3.484E-08	2.935E-08	1.823E-08	8.443E-09	4.427E-09	2.829E-09	2.009E-09
WNW	3.656E-08	4.234E-08	4.013E-08	3.376E-08	2.808E-08	1.720E-08	7.922E-09	4.175E-09	2.681E-09	1.910E-09
NW	2.196E-08	3.685E-08	4.004E-08	3.516E-08	2.979E-08	1.858E-08	8.707E-09	4.633E-09	2.993E-09	2.143E-09
NNW	1.626E-08	2.607E-08	3.060E-08	2.823E-08	2.466E-08	1.606E-08	7.847E-09	4.262E-09	2.776E-09	1.995E-09
N	4.265E-08	6.981E-08	8.139E-08	7.484E-08	6.527E-08	4.241E-08	2.067E-08	1.121E-08	7.290E-09	5.232E-09
NNE	7.597E-08	1.000E-07	1.069E-07	9.532E-08	8.197E-08	5.256E-08	2.544E-08	1.380E-08	8.991E-09	6.464E-09
NE	5.360E-08	7.888E-08	8.570E-08	7.661E-08	6.590E-08	4.221E-08	2.041E-08	1.107E-08	7.216E-09	5.193E-09
ENE	3.049E-08	4.075E-08	4.477E-08	4.086E-08	3.576E-08	2.370E-08	1.199E-08	6.721E-09	4.470E-09	3.262E-09
E	2.944E-08	4.829E-08	6.007E-08	5.865E-08	5.360E-08	3.806E-08	2.085E-08	1.233E-08	8.455E-09	6.297E-09
ESE	4.406E-08	5.883E-08	6.745E-08	6.404E-08	5.787E-08	4.105E-08	2.301E-08	1.407E-08	9.911E-09	7.541E-09
SE	6.060E-08	5.694E-08	5.526E-08	4.882E-08	4.233E-08	2.828E-08	1.491E-08	8.828E-09	6.133E-09	4.633E-09
SSE	6.550E-08	6.388E-08	5.646E-08	4.614E-08	3.777E-08	2.270E-08	1.029E-08	5.407E-09	3.483E-09	2.493E-09

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
8.000 DAY DECAY, DEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

SEGMENT BOUNDARIES IN MILES FROM THE SITE

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	5.017E-08	5.964E-08	5.849E-08	4.942E-08	4.079E-08	2.412E-08	1.036E-08	5.101E-09	3.131E-09	2.160E-09
SSW	2.514E-08	3.730E-08	4.052E-08	3.590E-08	3.044E-08	1.863E-08	8.289E-09	4.161E-09	2.579E-09	1.791E-09
SW	1.925E-08	3.005E-08	3.363E-08	3.033E-08	2.602E-08	1.622E-08	7.377E-09	3.763E-09	2.355E-09	1.646E-09
WSW	1.874E-08	2.611E-08	2.857E-08	2.600E-08	2.253E-08	1.431E-08	6.647E-09	3.439E-09	2.169E-09	1.524E-09
W	2.347E-08	3.039E-08	3.260E-08	2.949E-08	2.554E-08	1.633E-08	7.728E-09	4.082E-09	2.614E-09	1.859E-09
WNW	2.961E-08	3.168E-08	3.136E-08	2.769E-08	2.373E-08	1.510E-08	7.194E-09	3.851E-09	2.489E-09	1.780E-09
NW	1.620E-08	2.470E-08	2.928E-08	2.756E-08	2.433E-08	1.597E-08	7.835E-09	4.259E-09	2.777E-09	1.998E-09
NNW	1.262E-08	1.635E-08	2.117E-08	2.127E-08	1.954E-08	1.355E-08	7.001E-09	3.908E-09	2.577E-09	1.866E-09
N	3.240E-08	4.345E-08	5.599E-08	5.614E-08	5.153E-08	3.573E-08	1.846E-08	1.031E-08	6.794E-09	4.917E-09
NNE	5.842E-08	6.600E-08	7.590E-08	7.265E-08	6.522E-08	4.427E-08	2.260E-08	1.260E-08	8.320E-09	6.032E-09
NE	3.920E-08	5.095E-08	6.057E-08	5.834E-08	5.246E-08	3.557E-08	1.811E-08	1.008E-08	6.656E-09	4.828E-09
ENE	2.303E-08	2.598E-08	3.078E-08	3.015E-08	2.756E-08	1.936E-08	1.035E-08	5.975E-09	4.030E-09	2.967E-09
E	2.182E-08	2.809E-08	3.797E-08	4.006E-08	3.843E-08	2.925E-08	1.713E-08	1.051E-08	7.337E-09	5.528E-09
ESE	3.392E-08	3.684E-08	4.447E-08	4.486E-08	4.212E-08	3.143E-08	1.837E-08	1.145E-08	8.138E-09	6.231E-09
SE	4.994E-08	4.125E-08	4.122E-08	3.807E-08	3.390E-08	2.327E-08	1.239E-08	7.309E-09	5.059E-09	3.816E-09
SSE	5.213E-08	4.895E-08	4.581E-08	3.918E-08	3.292E-08	2.033E-08	9.374E-09	4.928E-09	3.165E-09	2.260E-09

Note: Directions are True North.

Table 2.7-10 Long-Term χ/Q (sec/m^3) for Routine Releases Along Various Distance Segments, 8.000 Day Decay, Depleted (Sheet 2 of 2)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
8.000 DAY DECAY, DEPLETED
0CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

DIRECTION FROM SITE	SEGMENT BOUNDARIES IN MILES FROM THE SITE .5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.498E-06	4.898E-07	2.092E-07	1.203E-07	7.966E-08	3.592E-08	1.145E-08	4.714E-09	2.619E-09	1.675E-09
SSW	1.183E-06	3.900E-07	1.672E-07	9.641E-08	6.395E-08	2.890E-08	9.236E-09	3.800E-09	2.108E-09	1.346E-09
SW	1.056E-06	3.493E-07	1.504E-07	8.689E-08	5.775E-08	2.619E-08	8.417E-09	3.480E-09	1.936E-09	1.239E-09
WSW	9.814E-07	3.249E-07	1.402E-07	8.122E-08	5.407E-08	2.460E-08	7.952E-09	3.305E-09	1.845E-09	1.183E-09
W	1.191E-06	3.962E-07	1.729E-07	1.009E-07	6.756E-08	3.105E-08	1.022E-08	4.312E-09	2.431E-09	1.570E-09
WNW	1.033E-06	3.432E-07	1.494E-07	8.709E-08	5.829E-08	2.681E-08	8.850E-09	3.756E-09	2.126E-09	1.378E-09
NW	1.054E-06	3.554E-07	1.562E-07	9.153E-08	6.148E-08	2.841E-08	9.424E-09	4.004E-09	2.266E-09	1.468E-09
NNW	8.999E-07	3.069E-07	1.354E-07	7.958E-08	5.355E-08	2.481E-08	8.251E-09	3.505E-09	1.981E-09	1.282E-09
N	2.310E-06	7.888E-07	3.469E-07	2.034E-07	1.366E-07	6.310E-08	2.088E-08	8.836E-09	4.982E-09	3.217E-09
NNE	2.912E-06	9.935E-07	4.376E-07	2.567E-07	1.725E-07	7.981E-08	2.649E-08	1.124E-08	6.350E-09	4.107E-09
NE	2.377E-06	8.115E-07	3.585E-07	2.107E-07	1.418E-07	6.570E-08	2.186E-08	9.295E-09	5.259E-09	3.406E-09
ENE	1.444E-06	4.989E-07	2.240E-07	1.330E-07	9.016E-08	4.229E-08	1.434E-08	6.185E-09	3.529E-09	2.298E-09
E	2.702E-06	9.482E-07	4.362E-07	2.627E-07	1.799E-07	8.579E-08	2.982E-08	1.311E-08	7.563E-09	4.964E-09
ESE	3.914E-06	1.354E-06	6.382E-07	3.903E-07	2.703E-07	1.313E-07	4.695E-08	2.112E-08	1.235E-08	8.187E-09
SE	2.771E-06	9.390E-07	4.387E-07	2.671E-07	1.845E-07	8.932E-08	3.183E-08	1.430E-08	8.362E-09	5.544E-09
SSE	1.548E-06	5.117E-07	2.260E-07	1.329E-07	8.959E-08	4.169E-08	1.402E-08	6.035E-09	3.446E-09	2.248E-09

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-11 Long-Term D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES
******************** RELATIVE DEPOSITION PER UNIT AREA (M**-2) AT FIXED POINTS BY DOWNWIND SECTORS ********************

DIRECTION FROM SITE	DISTANCES IN MILES 0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	3.039E-09	1.897E-09	1.544E-09	1.381E-09	9.561E-10	7.176E-10	5.564E-10	4.416E-10	3.568E-10	2.926E-10	2.429E-10
SSW	1.184E-09	8.178E-10	7.730E-10	7.624E-10	5.636E-10	4.356E-10	3.431E-10	2.746E-10	2.229E-10	1.832E-10	1.522E-10
SW	9.372E-10	6.500E-10	6.118E-10	6.036E-10	4.461E-10	3.453E-10	2.723E-10	2.182E-10	1.772E-10	1.457E-10	1.211E-10
WSW	9.115E-10	6.612E-10	5.927E-10	5.590E-10	3.989E-10	3.047E-10	2.386E-10	1.905E-10	1.545E-10	1.269E-10	1.055E-10
W	1.177E-09	8.409E-10	7.241E-10	6.617E-10	4.609E-10	3.485E-10	2.715E-10	2.161E-10	1.749E-10	1.436E-10	1.194E-10
WNW	1.599E-09	1.131E-09	8.545E-10	6.923E-10	4.326E-10	3.125E-10	2.376E-10	1.867E-10	1.501E-10	1.229E-10	1.022E-10
NW	8.198E-10	6.218E-10	5.076E-10	4.401E-10	2.918E-10	2.171E-10	1.677E-10	1.330E-10	1.075E-10	8.820E-11	7.334E-11
NNW	6.798E-10	5.102E-10	3.870E-10	3.116E-10	1.924E-10	1.386E-10	1.052E-10	8.265E-11	6.647E-11	5.445E-11	4.527E-11
N	1.856E-09	1.373E-09	1.030E-09	8.202E-10	5.015E-10	3.593E-10	2.720E-10	2.132E-10	1.713E-10	1.403E-10	1.166E-10
NNE	3.560E-09	2.438E-09	1.794E-09	1.422E-09	8.718E-10	6.231E-10	4.708E-10	3.686E-10	2.959E-10	2.420E-10	2.011E-10
NE	2.590E-09	1.685E-09	1.262E-09	1.031E-09	6.560E-10	4.753E-10	3.617E-10	2.843E-10	2.285E-10	1.870E-10	1.553E-10
ENE	1.563E-09	1.011E-09	7.263E-10	5.695E-10	3.472E-10	2.473E-10	1.865E-10	1.459E-10	1.170E-10	9.566E-11	7.944E-11
E	1.739E-09	1.149E-09	7.962E-10	5.938E-10	3.412E-10	2.359E-10	1.748E-10	1.354E-10	1.080E-10	8.816E-11	7.321E-11
ESE	2.690E-09	1.708E-09	1.179E-09	8.812E-10	5.117E-10	3.535E-10	2.616E-10	2.023E-10	1.612E-10	1.314E-10	1.090E-10
SE	4.132E-09	2.588E-09	1.758E-09	1.306E-09	7.562E-10	5.218E-10	3.859E-10	2.984E-10	2.378E-10	1.938E-10	1.608E-10
SSE	3.761E-09	2.348E-09	1.690E-09	1.343E-09	8.385E-10	5.999E-10	4.530E-10	3.544E-10	2.841E-10	2.322E-10	1.926E-10

0DIRECTION FROM SITE	DISTANCES IN MILES 5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	2.039E-10	1.064E-10	6.729E-11	3.511E-11	2.201E-11	1.548E-11	1.157E-11	9.015E-12	7.245E-12	5.959E-12	4.994E-12
SSW	1.278E-10	6.671E-11	4.218E-11	2.193E-11	1.370E-11	9.571E-12	7.116E-12	5.523E-12	4.426E-12	3.634E-12	3.043E-12
SW	1.016E-10	5.310E-11	3.361E-11	1.750E-11	1.094E-11	7.653E-12	5.695E-12	4.423E-12	3.545E-12	2.911E-12	2.438E-12
WSW	8.857E-11	4.636E-11	2.938E-11	1.535E-11	9.618E-12	6.771E-12	5.058E-12	3.937E-12	3.159E-12	2.594E-12	2.171E-12
W	1.003E-10	5.251E-11	3.329E-11	1.742E-11	1.094E-11	7.730E-12	5.793E-12	4.522E-12	3.637E-12	2.993E-12	2.509E-12
WNW	8.597E-11	4.526E-11	2.887E-11	1.531E-11	9.709E-12	7.023E-12	5.352E-12	4.228E-12	3.432E-12	2.843E-12	2.396E-12
NW	6.167E-11	3.245E-11	2.066E-11	1.090E-11	6.881E-12	4.927E-12	3.728E-12	2.930E-12	2.369E-12	1.957E-12	1.646E-12
NNW	3.812E-11	2.013E-11	1.286E-11	6.844E-12	4.350E-12	3.164E-12	2.421E-12	1.918E-12	1.560E-12	1.295E-12	1.093E-12
N	9.823E-11	5.187E-11	3.316E-11	1.766E-11	1.124E-11	8.190E-12	6.273E-12	4.977E-12	4.052E-12	3.365E-12	2.842E-12
NNE	1.692E-10	8.908E-11	5.684E-11	3.019E-11	1.918E-11	1.392E-11	1.064E-11	8.438E-12	6.872E-12	5.710E-12	4.829E-12
NE	1.305E-10	6.840E-11	4.348E-11	2.293E-11	1.450E-11	1.042E-11	7.920E-12	6.264E-12	5.102E-12	4.245E-12	3.601E-12
ENE	6.685E-11	3.515E-11	2.244E-11	1.192E-11	7.574E-12	5.497E-12	4.206E-12	3.338E-12	2.722E-12	2.266E-12	1.919E-12
E	6.169E-11	3.256E-11	2.086E-11	1.118E-11	7.159E-12	5.289E-12	4.105E-12	3.301E-12	2.724E-12	2.290E-12	1.961E-12
ESE	9.178E-11	4.820E-11	3.076E-11	1.639E-11	1.046E-11	7.674E-12	5.925E-12	4.742E-12	3.899E-12	3.268E-12	2.790E-12
SE	1.353E-10	7.108E-11	4.539E-11	2.423E-11	1.547E-11	1.132E-11	8.704E-12	6.921E-12	5.648E-12	4.696E-12	3.968E-12
SSE	1.619E-10	8.467E-11	5.379E-11	2.837E-11	1.795E-11	1.288E-11	9.768E-12	7.686E-12	6.221E-12	5.141E-12	4.321E-12

Note: Directions are True North.

Table 2.7-11 Long-Term D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles (Sheet 2 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
******************** RELATIVE DEPOSITION PER UNIT AREA (M**-2) AT FIXED POINTS BY DOWNWIND SECTORS ********************

DIRECTION	DISTANCES IN MILES										
FROM SITE	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	2.773E-09	1.735E-09	1.452E-09	1.325E-09	9.255E-10	7.018E-10	5.477E-10	4.364E-10	3.534E-10	2.901E-10	2.411E-10
SSW	1.144E-09	7.743E-10	7.406E-10	7.410E-10	5.524E-10	4.299E-10	3.400E-10	2.728E-10	2.218E-10	1.824E-10	1.516E-10
SW	9.066E-10	6.276E-10	5.977E-10	5.947E-10	4.413E-10	3.429E-10	2.710E-10	2.174E-10	1.767E-10	1.453E-10	1.208E-10
WSW	8.970E-10	6.425E-10	5.782E-10	5.494E-10	3.938E-10	3.022E-10	2.373E-10	1.897E-10	1.539E-10	1.265E-10	1.052E-10
W	1.159E-09	8.155E-10	7.041E-10	6.484E-10	4.539E-10	3.450E-10	2.696E-10	2.150E-10	1.742E-10	1.431E-10	1.190E-10
WNW	1.572E-09	1.114E-09	8.449E-10	6.864E-10	4.294E-10	3.108E-10	2.367E-10	1.861E-10	1.498E-10	1.227E-10	1.020E-10
NW	8.198E-10	6.218E-10	5.076E-10	4.401E-10	2.918E-10	2.171E-10	1.677E-10	1.330E-10	1.075E-10	8.820E-11	7.334E-11
NNW	6.798E-10	5.102E-10	3.870E-10	3.116E-10	1.924E-10	1.386E-10	1.052E-10	8.265E-11	6.647E-11	5.445E-11	4.527E-11
N	1.855E-09	1.372E-09	1.029E-09	8.195E-10	5.011E-10	3.591E-10	2.719E-10	2.132E-10	1.713E-10	1.403E-10	1.166E-10
NNE	3.456E-09	2.381E-09	1.765E-09	1.405E-09	8.619E-10	6.180E-10	4.679E-10	3.669E-10	2.947E-10	2.412E-10	2.005E-10
NE	2.440E-09	1.597E-09	1.214E-09	1.002E-09	6.398E-10	4.670E-10	3.571E-10	2.815E-10	2.267E-10	1.857E-10	1.543E-10
ENE	1.486E-09	9.816E-10	7.164E-10	5.649E-10	3.441E-10	2.457E-10	1.855E-10	1.453E-10	1.166E-10	9.536E-11	7.923E-11
E	1.675E-09	1.123E-09	7.869E-10	5.892E-10	3.383E-10	2.344E-10	1.739E-10	1.348E-10	1.077E-10	8.789E-11	7.301E-11
ESE	2.520E-09	1.613E-09	1.129E-09	8.516E-10	4.951E-10	3.449E-10	2.568E-10	1.994E-10	1.593E-10	1.301E-10	1.080E-10
SE	3.739E-09	2.416E-09	1.688E-09	1.269E-09	7.340E-10	5.100E-10	3.792E-10	2.942E-10	2.350E-10	1.918E-10	1.593E-10
SSE	3.371E-09	2.148E-09	1.593E-09	1.288E-09	8.067E-10	5.833E-10	4.437E-10	3.487E-10	2.804E-10	2.295E-10	1.906E-10

0DIRECTION	DISTANCES IN MILES										
FROM SITE	5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	2.024E-10	1.060E-10	6.722E-11	3.516E-11	2.204E-11	1.553E-11	1.161E-11	9.033E-12	7.244E-12	5.946E-12	4.971E-12
SSW	1.272E-10	6.655E-11	4.214E-11	2.195E-11	1.371E-11	9.580E-12	7.115E-12	5.513E-12	4.408E-12	3.611E-12	3.014E-12
SW	1.014E-10	5.304E-11	3.360E-11	1.751E-11	1.094E-11	7.656E-12	5.691E-12	4.413E-12	3.530E-12	2.892E-12	2.415E-12
WSW	8.834E-11	4.629E-11	2.936E-11	1.536E-11	9.625E-12	6.777E-12	5.061E-12	3.938E-12	3.158E-12	2.592E-12	2.167E-12
W	9.994E-11	5.240E-11	3.327E-11	1.743E-11	1.094E-11	7.735E-12	5.792E-12	4.515E-12	3.625E-12	2.978E-12	2.492E-12
WNW	8.581E-11	4.522E-11	2.886E-11	1.532E-11	9.710E-12	7.022E-12	5.343E-12	4.212E-12	3.409E-12	2.816E-12	2.365E-12
NW	6.167E-11	3.245E-11	2.066E-11	1.090E-11	6.879E-12	4.923E-12	3.719E-12	2.917E-12	2.353E-12	1.939E-12	1.626E-12
NNW	3.812E-11	2.013E-11	1.286E-11	6.844E-12	4.349E-12	3.160E-12	2.412E-12	1.906E-12	1.545E-12	1.278E-12	1.074E-12
N	9.821E-11	5.186E-11	3.316E-11	1.766E-11	1.123E-11	8.178E-12	6.251E-12	4.944E-12	4.010E-12	3.318E-12	2.789E-12
NNE	1.687E-10	8.896E-11	5.682E-11	3.021E-11	1.918E-11	1.391E-11	1.061E-11	8.378E-12	6.788E-12	5.611E-12	4.714E-12
NE	1.297E-10	6.819E-11	4.345E-11	2.296E-11	1.450E-11	1.041E-11	7.882E-12	6.191E-12	4.998E-12	4.121E-12	3.456E-12
ENE	6.668E-11	3.513E-11	2.244E-11	1.193E-11	7.570E-12	5.493E-12	4.189E-12	3.307E-12	2.679E-12	2.214E-12	1.860E-12
E	6.153E-11	3.253E-11	2.086E-11	1.119E-11	7.149E-12	5.267E-12	4.058E-12	3.226E-12	2.627E-12	2.178E-12	1.834E-12
ESE	9.096E-11	4.799E-11	3.073E-11	1.642E-11	1.047E-11	7.671E-12	5.889E-12	4.670E-12	3.795E-12	3.143E-12	2.644E-12
SE	1.342E-10	7.084E-11	4.538E-11	2.428E-11	1.549E-11	1.137E-11	8.738E-12	6.935E-12	5.639E-12	4.673E-12	3.932E-12
SSE	1.603E-10	8.429E-11	5.374E-11	2.844E-11	1.799E-11	1.295E-11	9.824E-12	7.727E-12	6.244E-12	5.151E-12	4.322E-12

Note: Directions are True North.

Table 2.7-11 Long-Term D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles (Sheet 3 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/ 8/2013

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES

******************** RELATIVE DEPOSITION PER UNIT AREA (M**-2) AT FIXED POINTS BY DOWNWIND SECTORS ********************

DIRECTION	DISTANCES IN MILES										
FROM SITE	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	4.819E-08	1.630E-08	8.367E-09	5.138E-09	2.561E-09	1.553E-09	1.050E-09	7.611E-10	5.787E-10	4.559E-10	3.691E-10
SSW	3.194E-08	1.080E-08	5.546E-09	3.405E-09	1.698E-09	1.030E-09	6.961E-10	5.045E-10	3.836E-10	3.022E-10	2.446E-10
SW	2.633E-08	8.902E-09	4.571E-09	2.807E-09	1.399E-09	8.486E-10	5.738E-10	4.158E-10	3.161E-10	2.491E-10	2.016E-10
WSW	2.286E-08	7.732E-09	3.970E-09	2.438E-09	1.215E-09	7.371E-10	4.983E-10	3.611E-10	2.746E-10	2.163E-10	1.751E-10
W	2.691E-08	9.101E-09	4.673E-09	2.869E-09	1.430E-09	8.676E-10	5.866E-10	4.251E-10	3.232E-10	2.546E-10	2.061E-10
WNW	2.495E-08	8.438E-09	4.333E-09	2.660E-09	1.326E-09	8.044E-10	5.439E-10	3.941E-10	2.997E-10	2.361E-10	1.911E-10
NW	2.242E-08	7.583E-09	3.893E-09	2.391E-09	1.192E-09	7.229E-10	4.887E-10	3.542E-10	2.693E-10	2.122E-10	1.718E-10
NNW	1.628E-08	5.504E-09	2.826E-09	1.735E-09	8.652E-10	5.247E-10	3.548E-10	2.571E-10	1.955E-10	1.540E-10	1.247E-10
N	4.309E-08	1.457E-08	7.481E-09	4.594E-09	2.290E-09	1.389E-09	9.391E-10	6.805E-10	5.175E-10	4.077E-10	3.300E-10
NNE	6.257E-08	2.116E-08	1.086E-08	6.671E-09	3.326E-09	2.017E-09	1.364E-09	9.882E-10	7.514E-10	5.920E-10	4.793E-10
NE	5.046E-08	1.706E-08	8.761E-09	5.379E-09	2.682E-09	1.627E-09	1.100E-09	7.969E-10	6.059E-10	4.774E-10	3.865E-10
ENE	2.720E-08	9.199E-09	4.723E-09	2.900E-09	1.446E-09	8.769E-10	5.929E-10	4.296E-10	3.267E-10	2.574E-10	2.084E-10
E	3.824E-08	1.293E-08	6.640E-09	4.077E-09	2.033E-09	1.233E-09	8.335E-10	6.040E-10	4.593E-10	3.618E-10	2.929E-10
ESE	5.097E-08	1.724E-08	8.849E-09	5.434E-09	2.709E-09	1.643E-09	1.111E-09	8.050E-10	6.121E-10	4.822E-10	3.904E-10
SE	4.574E-08	1.547E-08	7.942E-09	4.877E-09	2.431E-09	1.475E-09	9.970E-10	7.225E-10	5.493E-10	4.328E-10	3.504E-10
SSE	4.085E-08	1.381E-08	7.092E-09	4.355E-09	2.171E-09	1.317E-09	8.902E-10	6.451E-10	4.905E-10	3.865E-10	3.129E-10

0DIRECTION	DISTANCES IN MILES										
FROM SITE	5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	3.053E-10	1.496E-10	9.388E-11	4.745E-11	2.872E-11	1.926E-11	1.380E-11	1.036E-11	8.056E-12	6.435E-12	5.252E-12
SSW	2.024E-10	9.917E-11	6.222E-11	3.145E-11	1.904E-11	1.276E-11	9.145E-12	6.867E-12	5.339E-12	4.265E-12	3.481E-12
SW	1.668E-10	8.174E-11	5.129E-11	2.592E-11	1.569E-11	1.052E-11	7.538E-12	5.660E-12	4.401E-12	3.515E-12	2.869E-12
WSW	1.449E-10	7.099E-11	4.454E-11	2.251E-11	1.363E-11	9.136E-12	6.547E-12	4.916E-12	3.822E-12	3.053E-12	2.492E-12
W	1.705E-10	8.356E-11	5.243E-11	2.650E-11	1.604E-11	1.075E-11	7.706E-12	5.786E-12	4.499E-12	3.594E-12	2.933E-12
WNW	1.581E-10	7.748E-11	4.861E-11	2.457E-11	1.487E-11	9.971E-12	7.145E-12	5.365E-12	4.171E-12	3.332E-12	2.720E-12
NW	1.421E-10	6.962E-11	4.369E-11	2.208E-11	1.336E-11	8.961E-12	6.421E-12	4.821E-12	3.749E-12	2.994E-12	2.444E-12
NNW	1.031E-10	5.054E-11	3.171E-11	1.603E-11	9.701E-12	6.504E-12	4.661E-12	3.500E-12	2.721E-12	2.174E-12	1.774E-12
N	2.730E-10	1.338E-10	8.394E-11	4.243E-11	2.568E-11	1.722E-11	1.234E-11	9.264E-12	7.203E-12	5.754E-12	4.697E-12
NNE	3.964E-10	1.943E-10	1.219E-10	6.161E-11	3.729E-11	2.500E-11	1.792E-11	1.345E-11	1.046E-11	8.355E-12	6.820E-12
NE	3.197E-10	1.567E-10	9.830E-11	4.968E-11	3.007E-11	2.016E-11	1.445E-11	1.085E-11	8.435E-12	6.738E-12	5.500E-12
ENE	1.724E-10	8.446E-11	5.300E-11	2.679E-11	1.621E-11	1.087E-11	7.789E-12	5.849E-12	4.548E-12	3.633E-12	2.965E-12
E	2.423E-10	1.187E-10	7.451E-11	3.766E-11	2.279E-11	1.528E-11	1.095E-11	8.223E-12	6.393E-12	5.107E-12	4.168E-12
ESE	3.229E-10	1.583E-10	9.929E-11	5.019E-11	3.038E-11	2.037E-11	1.459E-11	1.096E-11	8.520E-12	6.806E-12	5.555E-12
SE	2.898E-10	1.420E-10	8.912E-11	4.504E-11	2.726E-11	1.828E-11	1.310E-11	9.835E-12	7.647E-12	6.108E-12	4.986E-12
SSE	2.588E-10	1.268E-10	7.957E-11	4.022E-11	2.434E-11	1.632E-11	1.170E-11	8.782E-12	6.828E-12	5.454E-12	4.452E-12

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-11 Long-Term D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles (Sheet 4 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 7/16/2013

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES

******************** RELATIVE DEPOSITION PER UNIT AREA (M**-2) AT FIXED POINTS BY DOWNWIND SECTORS ********************

DIRECTION	DISTANCES IN MILES										
FROM SITE	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	4.819E-08	1.630E-08	8.367E-09	5.138E-09	2.561E-09	1.553E-09	1.050E-09	7.611E-10	5.787E-10	4.559E-10	3.691E-10
SSW	3.194E-08	1.080E-08	5.546E-09	3.405E-09	1.698E-09	1.030E-09	6.961E-10	5.045E-10	3.836E-10	3.022E-10	2.446E-10
SW	2.633E-08	8.902E-09	4.571E-09	2.807E-09	1.399E-09	8.486E-10	5.738E-10	4.158E-10	3.161E-10	2.491E-10	2.016E-10
WSW	2.286E-08	7.732E-09	3.970E-09	2.438E-09	1.215E-09	7.371E-10	4.983E-10	3.611E-10	2.746E-10	2.163E-10	1.751E-10
W	2.691E-08	9.101E-09	4.673E-09	2.869E-09	1.430E-09	8.676E-10	5.866E-10	4.251E-10	3.232E-10	2.546E-10	2.061E-10
WNW	2.495E-08	8.438E-09	4.333E-09	2.660E-09	1.326E-09	8.044E-10	5.439E-10	3.941E-10	2.997E-10	2.361E-10	1.911E-10
NW	2.242E-08	7.583E-09	3.893E-09	2.391E-09	1.192E-09	7.229E-10	4.887E-10	3.542E-10	2.693E-10	2.122E-10	1.718E-10
NNW	1.628E-08	5.504E-09	2.826E-09	1.735E-09	8.652E-10	5.247E-10	3.548E-10	2.571E-10	1.955E-10	1.540E-10	1.247E-10
N	4.309E-08	1.457E-08	7.481E-09	4.594E-09	2.290E-09	1.389E-09	9.391E-10	6.805E-10	5.175E-10	4.077E-10	3.300E-10
NNE	6.257E-08	2.116E-08	1.086E-08	6.671E-09	3.326E-09	2.017E-09	1.364E-09	9.882E-10	7.514E-10	5.920E-10	4.793E-10
NE	5.046E-08	1.706E-08	8.761E-09	5.379E-09	2.682E-09	1.627E-09	1.100E-09	7.969E-10	6.059E-10	4.774E-10	3.865E-10
ENE	2.720E-08	9.199E-09	4.723E-09	2.900E-09	1.446E-09	8.769E-10	5.929E-10	4.296E-10	3.267E-10	2.574E-10	2.084E-10
E	3.824E-08	1.293E-08	6.640E-09	4.077E-09	2.033E-09	1.233E-09	8.335E-10	6.040E-10	4.593E-10	3.618E-10	2.929E-10
ESE	5.097E-08	1.724E-08	8.849E-09	5.434E-09	2.709E-09	1.643E-09	1.111E-09	8.050E-10	6.121E-10	4.822E-10	3.904E-10
SE	4.574E-08	1.547E-08	7.942E-09	4.877E-09	2.431E-09	1.475E-09	9.970E-10	7.225E-10	5.493E-10	4.328E-10	3.504E-10
SSE	4.085E-08	1.381E-08	7.092E-09	4.355E-09	2.171E-09	1.317E-09	8.902E-10	6.451E-10	4.905E-10	3.865E-10	3.129E-10

0DIRECTION	DISTANCES IN MILES										
FROM SITE	5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	3.053E-10	1.496E-10	9.388E-11	4.745E-11	2.872E-11	1.926E-11	1.380E-11	1.036E-11	8.056E-12	6.435E-12	5.252E-12
SSW	2.024E-10	9.917E-11	6.222E-11	3.145E-11	1.904E-11	1.276E-11	9.145E-12	6.867E-12	5.339E-12	4.265E-12	3.481E-12
SW	1.668E-10	8.174E-11	5.129E-11	2.592E-11	1.569E-11	1.052E-11	7.538E-12	5.660E-12	4.401E-12	3.515E-12	2.869E-12
WSW	1.449E-10	7.099E-11	4.454E-11	2.251E-11	1.363E-11	9.136E-12	6.547E-12	4.916E-12	3.822E-12	3.053E-12	2.492E-12
W	1.705E-10	8.356E-11	5.243E-11	2.650E-11	1.604E-11	1.075E-11	7.706E-12	5.786E-12	4.499E-12	3.594E-12	2.933E-12
WNW	1.581E-10	7.748E-11	4.861E-11	2.457E-11	1.487E-11	9.971E-12	7.145E-12	5.365E-12	4.171E-12	3.332E-12	2.720E-12
NW	1.421E-10	6.962E-11	4.369E-11	2.208E-11	1.336E-11	8.961E-12	6.421E-12	4.821E-12	3.749E-12	2.994E-12	2.444E-12
NNW	1.031E-10	5.054E-11	3.171E-11	1.603E-11	9.701E-12	6.504E-12	4.661E-12	3.500E-12	2.721E-12	2.174E-12	1.774E-12
N	2.730E-10	1.338E-10	8.394E-11	4.243E-11	2.568E-11	1.722E-11	1.234E-11	9.264E-12	7.203E-12	5.754E-12	4.697E-12
NNE	3.964E-10	1.943E-10	1.219E-10	6.161E-11	3.729E-11	2.500E-11	1.792E-11	1.345E-11	1.046E-11	8.355E-12	6.820E-12
NE	3.197E-10	1.567E-10	9.830E-11	4.968E-11	3.007E-11	2.016E-11	1.445E-11	1.085E-11	8.435E-12	6.738E-12	5.500E-12
ENE	1.724E-10	8.446E-11	5.300E-11	2.679E-11	1.621E-11	1.087E-11	7.789E-12	5.849E-12	4.548E-12	3.633E-12	2.965E-12
E	2.423E-10	1.187E-10	7.451E-11	3.766E-11	2.279E-11	1.528E-11	1.095E-11	8.223E-12	6.393E-12	5.107E-12	4.168E-12
ESE	3.229E-10	1.583E-10	9.929E-11	5.019E-11	3.038E-11	2.037E-11	1.459E-11	1.096E-11	8.520E-12	6.806E-12	5.555E-12
SE	2.898E-10	1.420E-10	8.912E-11	4.504E-11	2.726E-11	1.828E-11	1.310E-11	9.835E-12	7.647E-12	6.108E-12	4.986E-12
SSE	2.588E-10	1.268E-10	7.957E-11	4.022E-11	2.434E-11	1.632E-11	1.170E-11	8.782E-12	6.828E-12	5.454E-12	4.452E-12

Note: Directions are True North.

Table 2.7-12 Long-Term D/Q ($1/m^2$) for Routine Releases Along Various Distance Segments (Sheet 1 of 4)

1USNRC COMPUTER CODE - XOQDOQ, VERSION 2.0 RUN DATE: 8/28/2014

0XOQDOQ - North Anna COL (1996-98 Met Data)

EXIT RB - MIXED MODE RELEASE - NO PURGE RELEASES

0************************ RELATIVE DEPOSITION PER UNIT AREA (M**-2) BY DOWNWIND SECTORS ************************

SEGMENT BOUNDARIES IN MILES

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.550E-09	9.444E-10	5.535E-10	3.566E-10	2.432E-10	1.107E-10	3.644E-11	1.566E-11	9.071E-12	5.982E-12
SSW	7.782E-10	5.509E-10	3.404E-10	2.226E-10	1.524E-10	6.937E-11	2.277E-11	9.689E-12	5.560E-12	3.650E-12
SW	6.166E-10	4.363E-10	2.701E-10	1.769E-10	1.211E-10	5.522E-11	1.816E-11	7.746E-12	4.452E-12	2.924E-12
WSW	5.929E-10	3.926E-10	2.370E-10	1.543E-10	1.056E-10	4.819E-11	1.592E-11	6.845E-12	3.961E-12	2.605E-12
W	7.223E-10	4.556E-10	2.699E-10	1.748E-10	1.195E-10	5.458E-11	1.807E-11	7.810E-12	4.548E-12	3.005E-12
WNW	8.439E-10	4.369E-10	2.372E-10	1.502E-10	1.023E-10	4.702E-11	1.583E-11	7.071E-12	4.246E-12	2.852E-12
NW	5.030E-10	2.915E-10	1.670E-10	1.074E-10	7.342E-11	3.370E-11	1.128E-11	4.968E-12	2.944E-12	1.964E-12
NNW	3.808E-10	1.950E-10	1.051E-10	6.651E-11	4.534E-11	2.090E-11	7.073E-12	3.183E-12	1.925E-12	1.299E-12
N	1.013E-09	5.091E-10	2.718E-10	1.715E-10	1.168E-10	5.386E-11	1.825E-11	8.236E-12	4.995E-12	3.375E-12
NNE	1.772E-09	8.836E-10	4.705E-10	2.961E-10	2.014E-10	9.256E-11	3.122E-11	1.401E-11	8.472E-12	5.728E-12
NE	1.254E-09	6.591E-10	3.610E-10	2.286E-10	1.555E-10	7.114E-11	2.375E-11	1.051E-11	6.294E-12	4.260E-12
ENE	7.199E-10	3.522E-10	1.865E-10	1.171E-10	7.958E-11	3.654E-11	1.233E-11	5.535E-12	3.351E-12	2.273E-12
E	7.846E-10	3.505E-10	1.754E-10	1.083E-10	7.337E-11	3.383E-11	1.154E-11	5.314E-12	3.311E-12	2.297E-12
ESE	1.164E-09	5.235E-10	2.624E-10	1.616E-10	1.093E-10	5.014E-11	1.695E-11	7.718E-12	4.759E-12	3.278E-12
SE	1.741E-09	7.741E-10	3.872E-10	2.383E-10	1.611E-10	7.394E-11	2.504E-11	1.138E-11	6.945E-12	4.708E-12
SSE	1.682E-09	8.446E-10	4.527E-10	2.844E-10	1.930E-10	8.811E-11	2.939E-11	1.299E-11	7.722E-12	5.157E-12

0VENT AND BUILDING PARAMETERS:

RELEASE HEIGHT	(METERS)	52.77	REP. WIND HEIGHT	(METERS)	10.0
DIAMETER	(METERS)	2.40	BUILDING HEIGHT	(METERS)	46.1
EXIT VELOCITY	(METERS)	17.78	BLDG.MIN.CRS.SEC.AREA	(SQ.METERS)	3098.0
			HEAT EMISSION RATE	(CAL/SEC)	0.0

0AT THE RELEASE HEIGHT: / AT THE MEASURED WIND HEIGHT (10.0 METERS):

VENT RELEASE MODE	WIND SPEED (METERS/SEC)	/	VENT RELEASE MODE	WIND SPEED (METERS/SEC) STABLE CONDITIONS	WIND SPEED (METERS/SEC) UNSTABLE/NEUTRAL CONDITIONS
ELEVATED	LESS THAN 3.556	/	ELEVATED	LESS THAN 3.556	LESS THAN 3.556
MIXED	BETWEEN 3.556 AND 17.780	/	MIXED	BETWEEN 3.556 AND 17.780	BETWEEN 3.556 AND 17.780
GROUND LEVEL	ABOVE 17.780	/	GROUND LEVEL	ABOVE 17.780	ABOVE 17.780

Note: Directions are True North.

Table 2.7-12 Long-Term D/Q ($1/m^2$) for Routine Releases Along Various Distance Segments (Sheet 2 of 4)

```
1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  8/28/2014
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT TB - MIXED MODE RELEASE - NO PURGE RELEASES
0************************     RELATIVE DEPOSITION PER UNIT AREA (M**-2) BY DOWNWIND SECTORS     ************************
                                            SEGMENT BOUNDARIES IN MILES
```

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.458E-09	9.148E-10	5.442E-10	3.530E-10	2.413E-10	1.102E-10	3.646E-11	1.570E-11	9.087E-12	5.969E-12
SSW	7.483E-10	5.399E-10	3.371E-10	2.214E-10	1.517E-10	6.919E-11	2.278E-11	9.696E-12	5.550E-12	3.626E-12
SW	6.030E-10	4.316E-10	2.687E-10	1.763E-10	1.209E-10	5.514E-11	1.817E-11	7.747E-12	4.442E-12	2.904E-12
WSW	5.796E-10	3.876E-10	2.355E-10	1.537E-10	1.053E-10	4.811E-11	1.592E-11	6.850E-12	3.961E-12	2.602E-12
W	7.041E-10	4.487E-10	2.679E-10	1.740E-10	1.191E-10	5.447E-11	1.807E-11	7.814E-12	4.541E-12	2.990E-12
WNW	8.343E-10	4.338E-10	2.362E-10	1.498E-10	1.021E-10	4.697E-11	1.583E-11	7.067E-12	4.229E-12	2.825E-12
NW	5.030E-10	2.915E-10	1.670E-10	1.074E-10	7.342E-11	3.370E-11	1.128E-11	4.963E-12	2.931E-12	1.945E-12
NNW	3.808E-10	1.950E-10	1.051E-10	6.651E-11	4.534E-11	2.090E-11	7.072E-12	3.178E-12	1.913E-12	1.282E-12
N	1.012E-09	5.088E-10	2.717E-10	1.715E-10	1.168E-10	5.385E-11	1.825E-11	8.222E-12	4.962E-12	3.327E-12
NNE	1.742E-09	8.741E-10	4.675E-10	2.950E-10	2.008E-10	9.241E-11	3.122E-11	1.400E-11	8.410E-12	5.627E-12
NE	1.205E-09	6.435E-10	3.562E-10	2.267E-10	1.545E-10	7.087E-11	2.375E-11	1.049E-11	6.219E-12	4.134E-12
ENE	7.080E-10	3.494E-10	1.855E-10	1.167E-10	7.936E-11	3.650E-11	1.233E-11	5.525E-12	3.320E-12	2.221E-12
E	7.737E-10	3.479E-10	1.744E-10	1.079E-10	7.317E-11	3.379E-11	1.154E-11	5.285E-12	3.236E-12	2.184E-12
ESE	1.113E-09	5.075E-10	2.573E-10	1.596E-10	1.082E-10	4.987E-11	1.696E-11	7.704E-12	4.685E-12	3.152E-12
SE	1.664E-09	7.533E-10	3.801E-10	2.355E-10	1.596E-10	7.360E-11	2.506E-11	1.142E-11	6.957E-12	4.685E-12
SSE	1.581E-09	8.143E-10	4.429E-10	2.805E-10	1.909E-10	8.761E-11	2.942E-11	1.304E-11	7.761E-12	5.168E-12

```
0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)   71.30                  REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    1.95                  BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)   17.78                  BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                       HEAT EMISSION RATE     (CAL/SEC)       0.0
0AT THE RELEASE HEIGHT:                          /  AT THE MEASURED WIND HEIGHT ( 10.0 METERS):
 VENT RELEASE MODE   WIND SPEED (METERS/SEC)     /  VENT RELEASE MODE   WIND SPEED (METERS/SEC)       WIND SPEED (METERS/SEC)
                                                 /                      STABLE CONDITIONS             UNSTABLE/NEUTRAL CONDITIONS
     ELEVATED        LESS THAN  3.556            /      ELEVATED        LESS THAN  3.556              LESS THAN  3.556
     MIXED           BETWEEN    3.556 AND 17.780 /      MIXED           BETWEEN    3.556 AND 17.780   BETWEEN    3.556 AND 17.780
     GROUND LEVEL    ABOVE     17.780            /      GROUND LEVEL    ABOVE     17.780              ABOVE     17.780
```

Note: Directions are True North.

Table 2.7-12 Long-Term D/Q ($1/m^2$) for Routine Releases Along Various Distance Segments (Sheet 3 of 4)

```
1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  7/ 8/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
0************************     RELATIVE DEPOSITION PER UNIT AREA (M**-2) BY DOWNWIND SECTORS     ************************
                                            SEGMENT BOUNDARIES IN MILES
```

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	8.694E-09	2.686E-09	1.069E-09	5.841E-10	3.712E-10	1.594E-10	4.944E-11	1.960E-11	1.046E-11	6.477E-12
SSW	5.762E-09	1.780E-09	7.084E-10	3.871E-10	2.460E-10	1.057E-10	3.277E-11	1.299E-11	6.936E-12	4.293E-12
SW	4.749E-09	1.467E-09	5.839E-10	3.191E-10	2.028E-10	8.710E-11	2.701E-11	1.071E-11	5.717E-12	3.538E-12
WSW	4.125E-09	1.274E-09	5.071E-10	2.771E-10	1.761E-10	7.565E-11	2.346E-11	9.298E-12	4.965E-12	3.073E-12
W	4.855E-09	1.500E-09	5.969E-10	3.262E-10	2.073E-10	8.905E-11	2.761E-11	1.094E-11	5.844E-12	3.617E-12
WNW	4.502E-09	1.391E-09	5.534E-10	3.024E-10	1.922E-10	8.256E-11	2.560E-11	1.015E-11	5.419E-12	3.354E-12
NW	4.045E-09	1.250E-09	4.973E-10	2.718E-10	1.727E-10	7.420E-11	2.301E-11	9.119E-12	4.870E-12	3.014E-12
NNW	2.937E-09	9.072E-10	3.610E-10	1.973E-10	1.254E-10	5.386E-11	1.670E-11	6.619E-12	3.535E-12	2.188E-12
N	7.773E-09	2.402E-09	9.557E-10	5.222E-10	3.319E-10	1.426E-10	4.421E-11	1.752E-11	9.357E-12	5.792E-12
NNE	1.129E-08	3.487E-09	1.388E-09	7.583E-10	4.820E-10	2.070E-10	6.420E-11	2.544E-11	1.359E-11	8.410E-12
NE	9.103E-09	2.812E-09	1.119E-09	6.115E-10	3.887E-10	1.669E-10	5.177E-11	2.052E-11	1.096E-11	6.782E-12
ENE	4.908E-09	1.516E-09	6.033E-10	3.297E-10	2.095E-10	9.001E-11	2.791E-11	1.106E-11	5.907E-12	3.656E-12
E	6.899E-09	2.132E-09	8.482E-10	4.635E-10	2.946E-10	1.265E-10	3.924E-11	1.555E-11	8.305E-12	5.140E-12
ESE	9.195E-09	2.841E-09	1.130E-09	6.177E-10	3.926E-10	1.686E-10	5.230E-11	2.073E-11	1.107E-11	6.851E-12
SE	8.252E-09	2.550E-09	1.015E-09	5.544E-10	3.524E-10	1.514E-10	4.693E-11	1.860E-11	9.934E-12	6.149E-12
SSE	7.369E-09	2.277E-09	9.059E-10	4.950E-10	3.146E-10	1.351E-10	4.191E-11	1.661E-11	8.870E-12	5.490E-12

```
0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)    0.00                 REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    0.00                 BUILDING HEIGHT        (METERS)       46.1
     EXIT VELOCITY   (METERS)    0.00                 BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)  3098.0
                                                      HEAT EMISSION RATE     (CAL/SEC)       0.0
                                                      HEAT EMISSION RATE     (CAL/SEC)       0.0
0ALL GROUND LEVEL RELEASES.
```

Note: Directions are True North. The results on this page are applicable to releases from the RW-VS.

Table 2.7-12 Long-Term D/Q ($1/m^2$) for Routine Releases Along Various Distance Segments (Sheet 4 of 4)

```
1USNRC COMPUTER CODE - XOQDOQ,  VERSION 2.0         RUN DATE:  7/16/2013
0XOQDOQ - North Anna COL (1996-98 Met Data)
 EXIT TWR - GROUND LEVEL RELEASE - NO PURGE RELEASES
0*************************     RELATIVE DEPOSITION PER UNIT AREA (M**-2) BY DOWNWIND SECTORS     ************************
                                            SEGMENT BOUNDARIES IN MILES
```

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	8.694E-09	2.686E-09	1.069E-09	5.841E-10	3.712E-10	1.594E-10	4.944E-11	1.960E-11	1.046E-11	6.477E-12
SSW	5.762E-09	1.780E-09	7.084E-10	3.871E-10	2.460E-10	1.057E-10	3.277E-11	1.299E-11	6.936E-12	4.293E-12
SW	4.749E-09	1.467E-09	5.839E-10	3.191E-10	2.028E-10	8.710E-11	2.701E-11	1.071E-11	5.717E-12	3.538E-12
WSW	4.125E-09	1.274E-09	5.071E-10	2.771E-10	1.761E-10	7.565E-11	2.346E-11	9.298E-12	4.965E-12	3.073E-12
W	4.855E-09	1.500E-09	5.969E-10	3.262E-10	2.073E-10	8.905E-11	2.761E-11	1.094E-11	5.844E-12	3.617E-12
WNW	4.502E-09	1.391E-09	5.534E-10	3.024E-10	1.922E-10	8.256E-11	2.560E-11	1.015E-11	5.419E-12	3.354E-12
NW	4.045E-09	1.250E-09	4.973E-10	2.718E-10	1.727E-10	7.420E-11	2.301E-11	9.119E-12	4.870E-12	3.014E-12
NNW	2.937E-09	9.072E-10	3.610E-10	1.973E-10	1.254E-10	5.386E-11	1.670E-11	6.619E-12	3.535E-12	2.188E-12
N	7.773E-09	2.402E-09	9.557E-10	5.222E-10	3.319E-10	1.426E-10	4.421E-11	1.752E-11	9.357E-12	5.792E-12
NNE	1.129E-08	3.487E-09	1.388E-09	7.583E-10	4.820E-10	2.070E-10	6.420E-11	2.544E-11	1.359E-11	8.410E-12
NE	9.103E-09	2.812E-09	1.119E-09	6.115E-10	3.887E-10	1.669E-10	5.177E-11	2.052E-11	1.096E-11	6.782E-12
ENE	4.908E-09	1.516E-09	6.033E-10	3.297E-10	2.095E-10	9.001E-11	2.791E-11	1.106E-11	5.907E-12	3.656E-12
E	6.899E-09	2.132E-09	8.482E-10	4.635E-10	2.946E-10	1.265E-10	3.924E-11	1.555E-11	8.305E-12	5.140E-12
ESE	9.195E-09	2.841E-09	1.130E-09	6.177E-10	3.926E-10	1.686E-10	5.230E-11	2.073E-11	1.107E-11	6.851E-12
SE	8.252E-09	2.550E-09	1.015E-09	5.544E-10	3.524E-10	1.514E-10	4.693E-11	1.860E-11	9.934E-12	6.149E-12
SSE	7.369E-09	2.277E-09	9.059E-10	4.950E-10	3.146E-10	1.351E-10	4.191E-11	1.661E-11	8.870E-12	5.490E-12

```
0VENT AND BUILDING PARAMETERS:
     RELEASE HEIGHT  (METERS)    0.00                REP. WIND HEIGHT       (METERS)       10.0
     DIAMETER        (METERS)    0.00                BUILDING HEIGHT        (METERS)        0.0
     EXIT VELOCITY   (METERS)    0.00                BLDG.MIN.CRS.SEC.AREA  (SQ.METERS)     0.0
                                                     HEAT EMISSION RATE     (CAL/SEC)       0.0
```

2.8 Related Federal Project Activities

The information for this section is provided in ESP-ER Section 2.8 and in FEIS Section 2.11.

No new and significant information has been identified for this section. Dominion has identified no past, present, or reasonably foreseeable Federal or non-Federal action that would result in new and significant cumulative impacts.

Chapter 3 Plant Description

Per 10 CFR 51.50(c)(1)(i), an application at the Combined License Stage, referencing an early site permit, must contain "information to demonstrate that the design of the facility falls within the site characteristics and design parameters specified in the early site permit."

ESP-ER Table 3.1-9 identifies the bounding site characteristics and design parameter values for assessing the environmental impacts of constructing and operating nuclear power plants at the North Anna ESP site. These site characteristic and design parameter values (i.e., plant parameter values) were used by the NRC in its independent evaluation of impacts and, in some cases, the NRC substituted values based on its own analysis. FEIS Table I-1 presents the ESP site characteristic values used by the NRC. The ESP, Appendix D, identifies values of plant parameters considered in the environmental review of the application.

In accordance with 10 CFR 51.50(c)(1)(i) and FEIS Table J-1 (Rows 1 and 2), Table 3.0-1 and Table 3.0-2 provide an evaluation of the design of the Unit 3 ESBWR facility to determine if it falls within the ESP site characteristic values specified in the FEIS and the plant parameter values identified in ESP, Appendix D.

- Table 3.0-1 evaluates site characteristics. For each site characteristic listed in FEIS Table I-1, Table 3.0-1 identifies the ESP site characteristic value, the corresponding Unit 3 value, and provides an evaluation of whether the Unit 3 site characteristic value falls within the FEIS site characteristic value. Evaluations are included to provide clarification or additional information where needed, or to provide reference to other sections where further evaluation is provided. The environmental impacts documented in the FEIS, based on the site characteristic values in FEIS Table I-1, are considered bounding, and therefore resolved, when the ESP site characteristic value bounds the Unit 3 site characteristic value.
- Table 3.0-2 evaluates design parameters. For each plant parameter value listed in ESP Table D-1, Table 3.0-2 identifies the ESP plant parameter value, the corresponding Unit 3 design characteristic value, and provides an evaluation of whether the Unit 3 design characteristic value falls within the ESP plant parameter value. Evaluations are included to provide clarification or additional information where needed, or to provide reference to other sections where further evaluation is provided. The environmental impacts documented in the FEIS, based on the plant parameter values provided in ESP Table D-1 and FEIS Table I-2, are considered bounding, and therefore resolved, when the ESP plant parameter value bounds the Unit 3 design characteristic value.

10 CFR 51.50(c)(1) also requires that this ER address environmental issues that were not resolved in the ESP proceeding, or that are affected by new and significant information. This chapter provides additional plant description to the extent necessary to support these supplemental analyses.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Atmospheric Dispersion (χ/Q) (Design Basis Accident)		Time-dependent values as listed in FEIS Table 5-14		
Exclusion Area Boundary (EAB)	3.34×10^{-5} sec/m^3	0 to 2 hr interval	3.34×10^{-5} sec/m^3	The Unit 3 site characteristic value for the 0–2 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the EAB is taken from ESP-ER Table 3.1-9 and FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Atmospheric Dispersion (χ/Q) (Design Basis Accident) (continued)				
Low Population Zone (LPZ)	2.17×10^{-6} sec/m^3	0 to 8 hr interval	2.17×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 0–8 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	1.5×10^{-6} sec/m^3	8 to 24 hr interval	1.5×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-24 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	1.2×10^{-6} sec/m^3	1 to 4 day interval	1.2×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 1-4 day short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	9.0×10^{-7} sec/m^3	4 to 30 day interval	9.0×10^{-7} sec/m^3	The Unit 3 site characteristic value for the 4-30 day short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average)				
Atmospheric Dispersion (χ/Q)	χ/Q values presented in ESP-ER Table 2.7-14	The atmospheric dispersion coefficients used to estimate dose consequences of normal airborne releases.		
Residence	2.4×10^{-6} sec/m^3	No decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the no decay, undepleted long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	2.4×10^{-6} sec/m^3	2.26-day decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 2.26-day decay, undepleted long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	2.1×10^{-6} sec/m^3	8-day decay, depleted	RB-VS: 6.6×10^{-8} sec/m^3 TB-VS: 5.3×10^{-8} sec/m^3 RW-VS: 3.8×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 8-day decay, depleted long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
EAB	3.7×10^{-6} sec/m^3	No decay, undepleted	RB-VS: 7.1×10^{-8} sec/m^3 TB-VS: 5.2×10^{-8} sec/m^3 RW-VS: 3.3×10^{-6} sec/m^3	The Unit 3 site characteristic values for the no decay, undepleted long term (annual average) atmospheric dispersion factors, χ/Qs, for the EAB are taken from Table 2.7-4. The Unit 3 site characteristic values fall within (are less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	3.7×10^{-6} sec/m^3	2.26-day decay, undepleted	RB-VS: 7.1×10^{-8} sec/m^3 TB-VS: 5.2×10^{-8} sec/m^3 RW-VS: 3.3×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 2.26-day decay, undepleted long term (annual average) atmospheric dispersion factors, χ/Qs, for the EAB are taken from Table 2.7-4. The Unit 3 site characteristic values fall within (are less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	3.3×10^{-6} sec/m^3	8-day decay, depleted	RB-VS: 6.9×10^{-8} sec/m^3 TB-VS: 5.0×10^{-8} sec/m^3 RW-VS: 2.9×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 8-day decay, depleted long term (annual average) atmospheric dispersion factors, χ/Qs, for the EAB are taken from Table 2.7-4. The Unit 3 site characteristic values fall within (are less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Meat animal	1.4×10^{-6} sec/m^3	No decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the no decay, undepleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest meat animal are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	1.4×10^{-6} sec/m^3	2.26-day decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 2.26-day decay, undepleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest meat animal are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	1.2×10^{-6} sec/m^3	8-day decay, depleted	RB-VS: 6.6×10^{-8} sec/m^3 TB-VS: 5.3×10^{-8} sec/m^3 RW-VS: 3.8×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 8-day decay, depleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest meat animal are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Vegetable garden	2.0×10^{-6} sec/m^3	No decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the no decay, undepleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest vegetable garden are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	2.0×10^{-6} sec/m^3	2.26-day decay, undepleted	RB-VS: 6.8×10^{-8} sec/m^3 TB-VS: 5.5×10^{-8} sec/m^3 RW-VS: 4.2×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 2.26-day decay, undepleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest vegetable garden are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	1.8×10^{-6} sec/m^3	8-day decay, depleted	RB-VS: 6.6×10^{-8} sec/m^3 TB-VS: 5.3×10^{-8} sec/m^3 RW-VS: 3.8×10^{-6} sec/m^3	The Unit 3 site characteristic values for the 8-day decay, depleted long-term (annual average) atmospheric dispersion factors, χ/Qs, for the nearest vegetable garden are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Ground Deposition (D/Q)	D/Q values presented in ESP-ER Table 2.7-14 and the ESP, Appendix A	The ground deposition coefficients used to estimate dose consequences of normal airborne releases		
Residence	7.2×10^{-9} /m^2		RB-VS: 1.8×10^{-9} 1/m^2 TB-VS: 1.8×10^{-9} 1/m^2 RW-VS: 1.1×10^{-8} 1/m^2	The Unit 3 site characteristic values for the long-term (annual average) ground deposition factors, D/Qs, for the nearest residence are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
EAB	1.2×10^{-8} /m^2		RB-VS: 1.7×10^{-9} 1/m^2 TB-VS: 1.6×10^{-9} 1/m^2 RW-VS: 1.1×10^{-8} 1/m^2	The Unit 3 site characteristic values for the long-term (annual average) ground deposition factors, D/Qs, for the EAB are taken from Table 2.7-4. The Unit 3 site characteristic values fall within (are less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Meat animal	3.1×10^{-9} /m^2		RB-VS: 1.8×10^{-9} 1/m^2 TB-VS: 1.8×10^{-9} 1/m^2 RW-VS: 1.1×10^{-8} 1/m^2	The Unit 3 site characteristic values for the long-term (annual average) ground deposition factors, D/Qs, for the nearest meat animal are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 12.2-201 for NAPS ESP VAR 2.0-1.
Vegetable garden	6.0×10^{-9} /m^2		RB-VS: 1.8×10^{-9} 1/m^2 TB-VS: 1.8×10^{-9} 1/m^2 RW-VS: 1.1×10^{-8} 1/m^2	The Unit 3 site characteristic values for the long-term (annual average) ground deposition factors, D/Qs, for the nearest vegetable garden are provided in Table 2.7-2. The Unit 3 site characteristic value for the Radwaste Building vent stack release does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1 and the ESP, Appendix A. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences				
Normal	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	Radiological dose consequences due to gaseous and liquid releases from normal operation of the plant	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	
Liquid effluent	1.6 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.079 mrem/yr	The Unit 3 site characteristic value is the total body dose to the Maximally Exposed Individual (MEI) from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.
	1.4 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	0.26 mrem/yr	The Unit 3 site characteristic value is the thyroid dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See FSAR Table 12.2-20bR.
	5.0 mrem/yr	Other organ/bone (Value for two units, see ESP-ER Table 5.4-11)	1.1 mrem/yr	The Unit 3 site characteristic value is the other organ dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-2. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units for other organ/bone dose. See also FSAR Tables 12.2-20bR and 12.2-202.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences (continued)				
Gaseous effluent	4.8 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.48mrem/yr	The Unit 3 site characteristic value is the highest total body dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4 and 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-18bR and 12.2-203.
	25 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	4.7 mrem/yr	The Unit 3 site characteristic value is the highest thyroid dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4 and 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units and is well below the 40 CFR 190 limit. See also FSAR Tables 12.2-18bR and 12.2-203.
	6.5 mrem/yr	Other organ (Value for two units, see ESP-ER Table 5.4-11)	0.57mrem/yr	The Unit 3 site characteristic value is the highest other organ (liver) dose to the MEI from Unit 3 gaseous effluents. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units.
	6.2 mrem/yr	Skin (Value for one unit, see ESP-ER Table 5.4-10)	0.59mrem/yr	The Unit 3 site characteristic value is the highest skin dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4 and 5.4-5. It represents the summation of plume and ground shine doses. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1. See also FSAR Tables 12.2-18bR and 12.2-201.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences (continued)				
Total	6.4 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.56 mrem/yr	The Unit 3 site characteristic value is the total total-body dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	27 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	5.0 mrem/yr	The Unit 3 site characteristic value is the total thyroid dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	11 mrem/yr	Other organ (Value for two units, see ESP-ER Table 5.4-11)	1.6 mrem/yr	The Unit 3 site characteristic value is the total other organ dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	6.2 mrem/yr	Skin (Value for one unit, see ESP-ER Table 5.4-10)	0.59 mrem/yr	This Unit 3 site characteristic value is the total skin dose to the MEI from Unit 3 gaseous effluents as shown in Table 5.4-5. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1. See also FSAR Table 12.2-201.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Dose Consequences (continued)				
Post-Accident	10 CFR 50.34(a)(1) and 10 CFR 100 dose limits	Radiological dose consequences due to gaseous releases from postulated plant accidents Design basis accidents (DBA) as listed in FEIS Tables 5-15, 5-16, and 5-17 Severe accidents as listed in FEIS Tables 5-18, 5-19, and 5-20	10 CFR 50.34(a)(1) and 10 CFR 100 dose limits	The Unit 3 site characteristic criteria are taken from ESP-ER Table 3.1-9. The Unit 3 site characteristic criteria for Unit 3 fall within (are equal to) the ESP criteria specified in FEIS Table I-1. FEIS Tables 5-15 and 5-18 (ABWR) and FEIS Tables 5-16 and 5-19 (AP1000) apply to a non-ESBWR plant and hence are not applicable to Unit 3. ESP-ER Table 7.1-2 and FEIS Table 5-17 identify Design Basis Accident (DBA) dose consequences for the ESBWR at the EAB and LPZ. Table 7.1-2 provides DBA dose consequences for Unit 3. All Unit 3 DBA doses are lower than and bounded by the ESP DBA dose values for the ESBWR except for LOCA, which remains a small fraction of the regulatory limit. In addition, a new DBA, RWCU/SDC system line failure (pre-incident iodine spike), was added to the evaluation, which was not considered in the ESP-ER. Environmental risk values for the ESBWR are identified in FEIS Table 5-20.
Minimum Distance to Site Boundary	2854.9 ft	Minimum lateral distance from the ESP PPE boundaries to the EAB	2854.9 ft	The Unit 3 site characteristic value is taken from ESP-ER Table 3.1-9. See also ESP-ER Figure 2.1-1. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Liquid Radwaste System				
Normal Dose Consequences	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits		10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	
	1.6 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.079 mrem/yr	The Unit 3 site characteristic value is the total body dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.
	1.4 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	0.26 mrem/yr	The Unit 3 site characteristic value is the thyroid dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-20bR.
	5.0 mrem/yr	Other organ (Value for two units, see ESP-ER Table 5.4-11)	1.1 mrem/yr	The Unit 3 site characteristic value is the other organ dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-2. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Population Density				
Population density at the time of initial site approval and within about 5 years thereafter	Population density meets the guidance of RS-002, Section 2.1.3 for RG 4.7, Regulatory Position C.4	At the time of initial site approval and within about 5 years hereafter, the population densities, including weighted transient population, averaged over any radial distance out to 20 miles (cumulative population at a distance divided by the circular area at that distance), would not exceed 500 persons per square mile.	Population density meets the guidance of RS-002, Section 2.1.3 for RG 4.7, Regulatory Position C.4	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is, that at the time of initial site approval and within about 5 years hereafter, the population densities, including weighted transient population, averaged over any radial distance out to 20 miles (cumulative population at a distance divided by the circular area at that distance), would not exceed 500 persons per square mile. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion specified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density at 5 years meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population density at the time of initial operation	Population density meets the guidance of RS-002, Section 2.1.3	The population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 500 persons per square mile at the time of initial operation.	Population density meets the guidance of RS-002, Section 2.1.3	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is that the population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 500 persons per square mile at the time of initial operation. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion identified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density at the time of initial operation meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population density over the lifetime of the new units until 2065	Population density meets the guidance of RS-002, Section 2.1.3	The population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 1000 persons per square mile over the lifetime of new units.	Population density meets the guidance of RS-002, Section 2.1.3	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is that the population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 1000 persons per square mile over the lifetime of Unit 3. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion identified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density over the lifetime of Unit 3 meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population Center Distance	10 CFR 100.21(b) Meets requirement	The distance from the ESP PPE to the nearest boundary of a densely populated center containing more than about 25,000 residents is not less than one and one-third times the distance from the ESP PPE to the outer boundary of the LPZ.	10 CFR 100.21(b) Meets requirement	The Unit 3 site characteristic value is that the nearest population center to Unit 3 with more than 25,000 residents is the City of Charlottesville which is 36 miles away as described in ESP-ER Section 2.5.1.2 and ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion identified in FEIS Table I-1 and the ESP, Appendix A. (Note that the ESP site characteristic value for minimum population center distance is 8 miles as provided in ESP, Appendix A).
EAB	10 CFR 100.21(a) Meets requirement	The exclusion area boundary is the perimeter of a 5,000-ft-radius circle from the center of the originally-planned NAPS Unit 3 containment.	10 CFR 100.21(a) Meets requirement	The Unit 3 site characteristic value is a 5,000-ft-radius circle from the center of the originally-planned NAPS Unit 3 containment as described in ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion and is equal to the ESP value of a 5,000 ft-radius circle identified in FEIS Table I-1 and the ESP, Appendix A.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Population Density (continued)				
LPZ	10 CFR 100.21(a) Meets requirement	The LPZ is a 6-mile-radius circle centered at the NAPS Unit 1 containment building.	10 CFR 100.21(a) Meets requirement	The Unit 3 site characteristic value is a 6-mile-radius circle centered at the center of the Unit 1 containment building as described in ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion and is equal to the ESP value of a 6-mile-radius circle identified in FEIS Table I-1 and the ESP, Appendix A.

Except where specifically noted, the values provided from FEIS Table I-1 are for one unit.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Structure Height	≤ 234 ft	The height from finished grade to the top of the tallest power block structure, excluding cooling towers	234 ft	The tallest power block structure is the Turbine Building vent stack (see DCD Table 2B-1) at 71.3 m (234 ft) above finished grade. This is the Unit 3 design characteristic value. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Structure Foundation Embedment	≤ 140 ft	The depth from finished grade to the bottom of the basemat for the most deeply embedded power block structure	20 m (65.6 ft) Nominal	The Unit 3 design characteristic value for structure foundation embedment is based on the bottom of the deepest power block structure basemat, which is the reactor building at 20 m (65.62 ft) nominal, below finished ground level grade (El. 88.24 m (289.50 ft NAVD88 (290.36 ft NGVD29))). The embedment of 20 m (65.62 ft) is based on the lowest elevation of -15.5 m (50.85 ft) and a finished ground level grade of +4.5 m (14.76 ft), yielding a depth of 20 m (65.62 ft), not including concrete fill below the basemat. This Unit 3 design characteristic value is shown in FSAR Figure 2.5.4-206. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in ESP Table D-1.
Normal Plant Heat Sink				
Condenser/Heat Exchanger Duty	≤ 1.03×10^{10} Btu/hr	Waste heat rejected from the main condenser and the auxiliary heat exchangers during normal plant operation at full station load	≤ 1.03×10^{10} Btu/hr	The Unit 3 design characteristic value is 1.03×10^{10} Btu/hr maximum waste heat rejected from the main condenser and auxiliary heat exchangers. The main condenser heat rate of 1.0×10^{10} Btu/hr and the plant service water system heat rate of 3×10^{8} Btu/hr (based on one of two redundant trains operating) are shown in the appropriate FSAR tables. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Maximum Inlet Temperature Condenser/Heat Exchanger	100°F	Maximum intake temperature at condenser and heat exchanger inlet	100°F	The Unit 3 design characteristic value is a maximum inlet water temperature of 100°F for the condenser as identified in FSAR Table 10.4-3R. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

	ESP Plant Parameters [From ESP Table D-1]			
Item	**ESP Value**	**Description and References**	**Unit 3 Design Characteristic Value**	**Evaluation**
Unit 3 Closed-Cycle, Dry and Wet Tower				
Height	≤ 180 ft	The height above finished grade of the cooling towers	180 ft	The Unit 3 design characteristic value is the hybrid cooling tower height of 55 m (180 ft) above finished grade. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Make-Up Flow Rate	15,384 gpm, maximum (MWC mode) 22,268 gpm, maximum (EC mode)	The expected rate of removal of water from Lake Anna to replace water losses from the closed-cycle cooling water system	15,376 gpm (MWC mode) 22,260 gpm (EC mode)	The Unit 3 design characteristic values for the hybrid cooling tower makeup rate are the expected rates of water withdrawal from Lake Anna to replace water lost from the operation of the tower. These losses are from evaporation, blowdown, and drift. The hybrid cooling tower has two modes of operation, Maximum Water Conservation (MWC) and Energy Conservation (EC). The Unit 3 design characteristic values for the MWC and EC modes of operation fall within (are less than) the ESP plant parameter values identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1]: ESP Value	ESP Plant Parameters [From ESP Table D-1]: Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Evaporation Rate	8707 gpm, 365-day rolling average[a]	Maximum rates at which water is lost by evaporation resulting from operation of the plant cooling towers.	8977 gpm, average without mitigating action of 3-inch rise in pool level; 9695 gpm, average with mitigating action of 3-inch rise in pool level (96% plant capacity factor with wet tower cooling)	The ESP design parameter value of 8707 gpm presented in ESP Table D-1 was used by the NRC Staff to characterize the average evaporation rate over a 365 day period and does not include a 96% capacity factor. See the description in the 5th paragraph of FEIS Section 5.3.2. The Unit 3 design characteristics value of 8977 gpm (20 cfs) (without mitigating action) and 9695 gpm (21.6 cfs) (with the mitigating action of raising the normal pool level in the Lake Anna (North Anna Reservoir) by 3 inches) are estimates from the extended water budget model performed as part of the Instream Flow Incremental Methodology (IFIM) study discussed in Section 5.10.1.1. These are the expected long-term cooling tower evaporation rates using a 96% capacity factor. The Unit 3 evaporation rate of 8977 gpm value exceeds the 8707 gpm evaluated in FEIS Section 5.3.2 because it was based on the water budget model that was extended to 2007 to cover the more recent climatic conditions. The Unit 3 evaporation rate with the mitigating action is higher because of the extended model period, and because the mitigating action of raising the pool level increases the frequency at which the lake level would be greater or equal to 250 ft msl. Consequently, the increased frequency of higher lake level would result in an increased frequency when the Unit 3 cooling towers would be operating in the EC mode. While the estimated evaporation rate would be higher, the frequency of reduced lake level (248 ft msl and lower) and downstream flow at 20 cfs would decrease because of the increased pool level. The hydrologic evaluation with respect to water-use impact of the plant with and without mitigating action is discussed in Section 5.10.1.3, which shows that the impacts of Unit 3 *(continued)*

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Evaporation Rate *(continued)*				on downstream flow and on lake levels are SMALL, and the lake mitigating action of raising the normal pool level to Elevation 250.25 ft msl would further reduce the impact.
	None[b]		11,532 gpm (MWC)	The Unit 3 design characteristic value of 11,532 gpm is taken from ESP-ER Table 3.1-9 for the MWC mode. The Unit 3 design characteristic value for the MWC mode of operation falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
	16,695 gpm, maximum (EC mode)		16,695 gpm (EC)	The Unit 3 design characteristic value of 16,695 gpm is taken from ESP-ER Table 3.1-9 for the EC mode. The Unit 3 design characteristic value for the mode of operation falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Drift Rate	8 gpm, maximum (MWC mode) 8 gpm, maximum (EC mode)	Expected rates at which water is lost by drift resulting from operation of the plant cooling towers based on 0.001% of cooling water flow	8 gpm (MWC) 8 gpm (EC)	The Unit 3 design characteristic values of 8 gpm for the MWC and EC modes are taken from ESP-ER Table 3.1-9. The Unit 3 hybrid cooling tower drift rate is the expected rate at which water is lost through drift from operation of the tower. The Unit 3 design characteristic values for the MWC and EC modes of operation falls within (are equal to) the ESP plant parameter values identified in ESP Table D-1.
Blowdown Flow Rate	3844 gpm, maximum (MWC mode) 5565 gpm, maximum (EC mode)	Flow rate of the blowdown stream from the closed-cycle cooling water system to the WHTF	3837 gpm (MWC) 5558 gpm (EC)	The Unit 3 design characteristic value for the hybrid cooling tower blowdown rate is the expected rate at which water is lost through blowdown flow from the cooling tower system to the WHTF. The Unit 3 design characteristic values for the MWC and EC modes of operation falls within (are less than) the ESP plant parameter values identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Blowdown Temperature	100°F, maximum	The maximum expected temperature of the cooling tower blowdown stream to the WHTF	100°F, maximum	The Unit 3 design characteristic value of 100°F is taken from ESP-ER Table 3.1-9. The maximum Unit 3 cooling tower blowdown temperature is the same as the maximum condenser inlet water temperature. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Blowdown Constituents and Concentrations		The maximum expected concentrations for anticipated constituents in the cooling water system blowdown to the WHTF		
Free Available Chlorine	< 0.3 ppm		Less than detectable (< 0.1 ppm)	The Unit 3 design characteristic value for maximum free chlorine concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow to the WHTF is “less than detectable,” (<0.1 ppm). The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.
Copper	<1 ppm		≤ 0.03 ppm	The Unit 3 design characteristic value for maximum Unit 3 copper concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow to the WHTF is 0.03 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	 Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Iron	<1 ppm		≤2.4 ppm	The Unit 3 design characteristic value for maximum expected iron concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow to the WHTF is 2.4 ppm. The Unit 3 design characteristic value does not fall within (is not equal to or less than) the ESP plant parameter value identified in ESP Table D-1. Although the Unit 3 value exceeds the ESP plant parameter, iron is not a priority pollutant in 40 CFR 423, Appendix A, and the Virginia Department of Environmental Quality has no water quality standard for it. Upon dilution in the WHTF, the iron concentration falls within the ESP plant parameter. See also Section 3.6.
Sulfate	< 300 ppm		≤65 ppm	The Unit 3 design characteristic value for maximum sulfate concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow to the WHTF is 65 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.
Total Dissolved Solids	< 3000 ppm		≤550 ppm	The Unit 3 design characteristic value for maximum concentration (based on 9 cycles of concentration) of total dissolved solids (TDS) contained in the Unit 3 cooling tower blowdown flow to the WHTF is 550 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.
Heat Rejection Rate	≤1.03E10 Btu/hr	The expected maximum heat rejection rate to the atmosphere during normal operation at full station load.	$\leq 1.03 \times 10^{10}$ Btu/hr	The Unit 3 design characteristic value is 1.03×10^{10} Btu/hr maximum waste heat rejected from the main condenser and auxiliary heat exchangers. The main condenser heat rate of 1.0×10^{10} Btu/hr and the plant service water system heat rate of 3×10^{8} Btu/hr (based on one of two redundant trains operating) are shown in the appropriate FSAR tables. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1]		Unit 3 Design Characteristic Value	Evaluation
	ESP Value	Description and References		
Noise	< 65 dBA EAB	Maximum expected sound level at the EAB from operation of the cooling towers	< 65 dBA EAB	The Unit 3 site characteristic value is less than 65 dBA based on the confirmatory analysis described in Section 5.8. This analysis demonstrates that the maximum expected sound level of operation of the Unit 3 Circulating Water and Plant Service Water system cooling towers is less than 65 dBA. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Unit 4 Dry Cooling Towers				
Evaporation Rate	None or negligible (on the order of 1 gpm, average)	The expected rate at which water is lost by evaporation from the cooling water system	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Height	≤180 ft	The vertical height above finished grade of the cooling towers	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Makeup Flow Rate	None or negligible (on the order of 1 gpm, average)	The expected rate of removal of water from Lake Anna to replace evaporative water losses from the cooling water system	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Noise	< 60 dBA at EAB	Maximum expected sound level at the EAB from operation of the cooling towers	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.

Table 3.0-2 Evaluation of ESP Design Parameters

	ESP Plant Parameters [From ESP Table D-1]			
Item	**ESP Value**	**Description and References**	**Unit 3 Design Characteristic Value**	**Evaluation**
Heat Rejection Rate	$\leq 1.03 \times 10^{10}$ Btu/hr	Waste heat rejected to the atmosphere from the cooling water system, during normal plant operation at full station load	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Ultimate Heat Sink (UHS)				
Mechanical Draft Cooling Towers				
Blowdown Constituents and Concentrations		The maximum expected concentrations for anticipated constituents in the UHS blowdown to the WHTF		
Free Available Chlorine	< 0.3 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Copper	<1 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Iron	<1 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Sulfate	< 300 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Total Dissolved Solids	< 3000 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Ultimate Heat Sink (UHS) (continued) Mechanical Draft Cooling Towers (continued)				
Blowdown Flow Rate	144 gpm expected, 850 gpm maximum	The normal expected and maximum flow rate of the blowdown stream from the UHS system to the WHTF	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Evaporation Rate	411 gpm normal, 850 gpm shutdown	The expected (and maximum) rate at which water is lost by evaporation from the UHS System	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Height	≤ 60 ft	The vertical height above finished grade of mechanical draft cooling towers associated with the UHS system	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Maximum Consumption of Raw Water	850 gpm, nominal	The expected maximum short-term consumptive use of water from Lake Anna by the UHS system (evaporation and drift losses)	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Monthly Average Consumption of Raw Water	411 gpm	The expected normal operating consumption of water from Lake Anna by the UHS system (evaporation and drift losses)	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Release Point				
Elevation	Ground Level	The elevation above finished grade of the release point for routine operational and accident sequence releases	Mixed mode and ground level (routine operational releases); ground level (accident sequence releases)	This Unit 3 design characteristic value for routine operational releases includes mixed mode release points from the vent stacks of the Turbine Building and Reactor Building along with ground level releases from the vent stack of the Radwaste Building and the CIRC cooling tower. The Unit 3 design characteristic value for routine operational releases does not fall within (is not the same as) the ESP plant parameter value identified in ESP Table D-1. The Unit 3 design characteristic value for accident sequence releases is a ground level release. The Unit 3 design characteristic value for accident sequence releases falls within (is the same as) the ESP plant parameter value identified in ESP Table D-1.
Source Term				
Gaseous (Normal)	Maximum values presented in Tables D-2 and D-3	The annual activity, by isotope, contained in routine plant airborne effluent streams	Values presented in Table 5.4-3	The Unit 3 design characteristic source term values for normal gaseous releases are provided in Table 5.4-3. All Unit 3 design characteristic values fall within (are less than) the ESP plant parameter values identified in ESP Table D-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Atmospheric (Design Basis Accidents)	Ci as indicated in			
	Table D-4	AP1000 Main Steam Line Break, Pre-existing Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-5	AP1000 Main Steam Line Break, Accident-Initiated Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-6	ABWR Cleanup Water Line Break	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-7	ESBWR Feedwater System Pipe Break	MBq values presented in DCD Table 15.4-15	The Unit 3 design characteristic source term values for a FSPB are provided in DCD Table 15.4-15. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Table D-7. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-6a. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, Unit 3 FSPB doses are higher than those shown in ESP-ER Table 7.1-6d; however, they remain well below regulatory limits.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Atmospheric (Design Basis Accidents) *(continued)*	Table D-8	AP1000 Locked Rotor Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-9	AP1000 Rod Ejection Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-10	ABWR Failure of Small Lines Carrying Primary Coolant Outside Containment	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-13	AP1000 Steam Generator Tube Rupture, Accident Initiated Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-14	ABWR Main Steam Line Break	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-15	ESBWR Main Steam Line Break	MBq values presented in DCD Table 15.4-12	The Unit 3 design characteristic source term values for an MSLB are provided in DCD Table 15.4-12. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Table D-15. Not only have the source terms listed in ESP Table D-15 changed, but additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-4. See Section 7.1 for the analysis of radiological consequences of accidental releases. As shown in Section 7.1, the LPZ dose for MSLB equilibrium iodine is marginally higher than that shown in ESP-ER Table 7.1-20c, but all MSLB doses remain well below regulatory limits.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Atmospheric (Design Basis Accidents) *(continued)*	Table D-16	AP1000 Loss-of-Coolant Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-17	ABWR Loss-of-Coolant Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-18	ESBWR Loss-of Coolant Accident	MBq values presented in DCD Table 15.4-7	The Unit 3 design characteristic source term values for a LOCA are provided in DCD Table 15.4-7. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Table D-18. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-5. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, the resultant LOCA doses, though marginally higher than those shown in ESP-ER Table 7.1-24b, remain well below 10 CFR 50.34(a)(1) and SRP limits.
	Table D-19	AP1000 Fuel Handling Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-20	ABWR Fuel Handling Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	Table D-21	ESBWR Fuel Handling Accident	MBq values presented in DCD Table 15.4-3a	The Unit 3 design characteristic source term values for an FHA are provided in DCD Table 15.4-3a. The Unit 3 design characteristic values fall within (are less than) the ESP plant parameter values identified in ESP Table D-21. See Section 7.1 for the analysis of radiological consequences of accidental releases.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Atmospheric (Design Basis Accidents) *(continued)*	Table D-22	ESBWR Cleanup Water Line Break	MBq values presented in DCD Table 15.4-22	The Unit 3 design characteristic source term values for CWLB are provided in DCD Table 15.4-22. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Table D-22. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-6. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, some Unit 3 CWLB doses are marginally higher than those shown in ESP-ER Table 7.1-32; however, they remain well below regulatory limits.
	Table D-11	ESBWR Failure of Small Lines Carrying Primary Coolant Outside Containment	MBq values presented in DCD Tables 15.4-18a and 15.4-18b	The Unit 3 design characteristic source term values for an FSLCPCOC are provided in DCD Tables 15.4-18a and 15.4-18b. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Table D-11. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-3. See Section 7.1 for the analysis of radiological consequences of accidental releases. As shown in Section 7.1, the resultant FSLCPCOC dose at the LPZ is marginally higher than that shown in ESP-ER Table 7.1-13b, but all FSLCPCOC doses remain well below regulatory limits.
	Table D-12	AP1000 Steam Generator Tube Rupture, Pre-Existing Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.

Table 3.0-2 Evaluation of ESP Design Parameters

	ESP Plant Parameters [From ESP Table D-1]			
Item	ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Tritium	3500 Ci/yr (maximum values)	The annual activity of tritium contained in routine plant airborne effluent streams	250 Ci/yr	The Unit 3 design characteristic annual activity of tritium contained in routine plant airborne effluent streams is 250 Ci/yr and is shown in Table 5.4-3. The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Liquid Radwaste System				
Release Point Dilution Factor	1000 (minimum)	The ratio of liquid potentially radioactive effluent streams to liquid nonradioactive effluent streams from plant systems to the WHTF through the discharge canal used for NAPS Units 1 and 2	1000	The Unit 3 dilution factor is shown in FSAR Table 12.2-20aR, which indicates a minimum dilution factor requirement of 1000 as the basis for liquid effluent dose calculations. Unit 3 effluent streams (both radiological and nonradiological) are directed to the Discharge Canal. At the Discharge Canal, the Unit 3 effluents are further mixed and diluted with the much larger quantity of water there. This dilution process is further described in Section 5.2. The resulting design characteristic dilution factor for Unit 3 effluents is therefore greater than 1000. The Unit 3 design characteristic value falls within (is equal to or greater than) the ESP plant parameter value identified in ESP Table D-1.
Liquid	Values presented in Tables D-23 and D-24 (maximum values)	The annual activity, by isotope, contained in routine plant liquid effluent streams	Values presented in Table 5.4-1	The Unit 3 design characteristic source term values for normal liquid effluent releases are provided in Table 5.4-1. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP plant parameter values identified in ESP Tables D-23 and D-24. Some source term activities have increased, and others are no longer present. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-7. The sum of the activity releases falls within the sum of activities in ESP Tables D-23 and D-24.
Tritium	≤850 Ci/yr	The annual activity of tritium contained in routine plant liquid effluent streams	14 Ci/yr	The Unit 3 design characteristic annual activity of tritium contained in routine plant liquid effluent streams is 14 Ci/yr as shown in Table 5.4-1. The Unit 3 design characteristic value falls within (is less than) the single unit value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	ESP Plant Parameters [From ESP Table D-1] Description and References	Unit 3 Design Characteristic Value	Evaluation
Solid Radwaste System				
Activity	≤ 2700 Ci/yr	The annual activity contained in solid radioactive wastes generated during routine plant operations	1718] Ci/yr	The Unit 3 design characteristic annual activity contained in solid radioactive wastes generated during routine plant operations is 1718 Ci/yr. The Unit 3 design characteristic value falls within (is less than) the ESP plant parameter value identified in ESP Table D-1.
Volume	≤ 9041 cu ft/yr (Per Unit)	The expected volume of solid radioactive wastes generated during routine plant operations	16,742 cu ft/yr	This Unit 3 design characteristic expected volume of solid radioactive waste generated during routine plant operations is 16,742 cu ft/yr. The volume for Unit 3 does not fall within the single unit value identified in ESP Table D-1. However, the volume for Unit 3 does fall within the overall site value evaluated in the FEIS for two units. Furthermore, the number of waste shipments based on DCD Table 11.4-2 volumes remains well below the one truck shipment per day condition given in 10 CFR 51.52(c), Table S-4.
Plant Characteristics				
Acreage	Approximately 128.5 acres [Both units]	Approximate area on the NAPS site that would be affected on a long-term basis as a result of additional permanent facilities	Approximately 133 acres as shown in Figure 1.1-1	The Unit 3 design characteristic value of approximately 133 acres is the area on the NAPS site that will be affected on a long term basis by the construction of permanent Unit 3 facilities. These areas are shown in Figure 1.1-1. The Unit 3 design characteristic value does not fall within (is greater than) the ESP plant parameter value identified in ESP Table D-1 for two units.
Megawatts Thermal	≤ 4500 MWt	The thermal power generated by one unit (may be the total of several modules)	4500 MWt (Rated)	This Unit 3 design characteristic value of 4500 MWt is the rated reactor thermal power, as described in Section 1.1. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Plant Characteristics (continued)				
Plant Population – Operation	Approximately 720 permanent employees (both units)	Anticipated number of new employees required for operation of the new units	500 permanent employees	The Unit 3 value of 500 is the anticipated number of new employees required for operation of Unit 3. The Unit 3 value falls within the total (two-unit) value identified in the ESP. The Unit 3 value falls within (is less than) the ESP plant parameter value for two units identified in ESP Table D-1.
Plant Population – Refueling/Major Maintenance	Approximately 700 to 1000 temporary workers during planned outages	Anticipated number of additional workers onsite during planned outages of the new units	1000 temporary workers	The Unit 3 value of 1,000 is the anticipated number of additional workers needed on site during Unit 3 planned outages. The Unit 3 value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Plant Population – Construction	5000 people maximum (simultaneous construction)	Peak workforce of 5000 for construction of both new units	[4100 people	The Unit 3 value of 4100 is the expected peak number of construction workers that are required for the construction of Unit 3. The Unit 3 value falls within (is less than) the ESP plant parameter value for two units identified in ESP Table D-1.
Maximum Fuel Enrichment for Light-Water-Cooled Reactors	5%	Concentration of U-235 in fuel	5%	The Unit 3 design characteristic value is 5% maximum concentration of U-235 in the Unit 3 fuel. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.
Maximum Fuel Burn-up for Light-Water-Cooled Reactors	62,000 MWd/MTU	The value derived by calculating the reactor thermal power multiplied by the time of irradiation divided by fuel mass (expressed as megawatt-days per metric ton of irradiated fuel)	62,000 MWd/MTU	The Unit 3 design characteristic value is 62,000 MWd/MTU maximum fuel burn-up for Unit 3. The Unit 3 design characteristic value falls within (is equal to) the ESP plant parameter value identified in ESP Table D-1.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Plant Parameters [From ESP Table D-1]		Unit 3 Design Characteristic Value	Evaluation
	ESP Value	Description and References		
Plant Characteristics (continued)				
Maximum Fuel Enrichment for Gas-Cooled Reactors	19.8%	Concentration of U-235 in fuel	Not Applicable	This design parameter is not applicable because it is related to a non-LWR plant.
Maximum Fuel Burn-up for Gas-Cooled Reactors	133,000 MWd/MTU	The value derived by calculating the reactor thermal power multiplied by the time of irradiation divided by fuel mass (expressed as megawatt-days per metric ton of irradiated fuel)	Not Applicable	This design parameter is not applicable because it is related to a non-LWR plant.

a. The staff used a 100 percent capacity factor based on a 365-day rolling average evaporative water use vs. the applicant's 96 percent capacity factor based on long term annual average evaporative water use.

b. FEIS Table I-2 presents no value for the MWC mode evaporation rate. However, it states on page 5-11: "The definition of the PPE instantaneous maximum evaporation rate parameters for the MWC and EC modes was unchanged." This indicates that NRC accepted the 11,532 gpm maximum as the bounding value for MWC mode evaporation rate. In addition, the value of 11,532 gpm was shown in NUREG-1811, Supp 1, (SDEIS).

Unless noted otherwise, the ESP design parameter for one unit is one half of the two-unit value shown, when it is noted that the ESP value is for two units.

Table 3.0-3 Comparison of Unit 3 and ESP Activity Releases for Failure of Small Lines Carrying Primary Coolant Outside Containment Accident

	ESP Activity Release (Ci)			Unit 3 Activity Release (Ci)			Unit 3 Activity Release (MBq)		
Isotope	**0–2 hr**	**2–8 hr**	**Total**	**0–2 hr**	**2–6 hr**	**Total**	**0–2 hr**	**2–6 hr**	**Total**
Co-58	NP	NP	NP	1.2E-03	7.5E-04	2.0E-03	4.5E+01	2.8E+01	7.3E+01
Co-60	NP	NP	NP	2.4E-03	1.5E-03	3.9E-03	8.9E+01	5.6E+01	1.5E+02
Sr-89	NP	NP	NP	5.6E-03	3.5E-03	9.0E-03	2.1E+02	1.3E+02	3.3E+02
Sr-90	NP	NP	NP	3.9E-04	2.4E-04	6.3E-04	1.4E+01	8.9E+00	2.3E+01
Sr-91	NP	NP	NP	2.2E-01	1.4E-01	3.5E-01	8.0E+03	4.9E+03	1.3E+04
Sr-92	NP	NP	NP	4.9E-01	3.0E-01	7.9E-01	1.8E+04	1.1E+04	2.9E+04
Y-90	NP	NP	NP	3.9E-04	2.4E-04	6.3E-04	1.4E+01	8.9E+00	2.3E+01
Y-91	NP	NP	NP	2.3E-03	1.4E-03	3.7E-03	8.4E+01	5.2E+01	1.4E+02
Y-92	NP	NP	NP	2.9E-01	1.8E-01	4.8E-01	1.1E+04	6.8E+03	1.8E+04
Y-93	NP	NP	NP	2.2E-01	1.4E-01	3.5E-01	8.0E+03	4.9E+03	1.3E+04
Zr-95	NP	NP	NP	4.4E-04	2.8E-04	7.2E-04	1.6E+01	1.0E+01	2.7E+01
Nb-95	NP	NP	NP	4.4E-04	2.8E-04	7.2E-04	1.6E+01	1.0E+01	2.7E+01
Mo-99	NP	NP	NP	1.1E-01	6.8E-02	1.8E-01	4.1E+03	2.5E+03	6.6E+03
Tc-99m	NP	NP	NP	1.1E-01	6.8E-02	1.8E-01	4.1E+03	2.5E+03	6.6E+03
Ru-103	NP	NP	NP	1.1E-03	6.9E-04	1.8E-03	4.1E+01	2.6E+01	6.7E+01
Ru-106	NP	NP	NP	1.7E-04	1.1E-04	2.8E-04	6.3E+00	3.9E+00	1.0E+01
Te-129m	NP	NP	NP	2.3E-03	1.4E-03	3.7E-03	8.4E+01	5.2E+01	1.4E+02
Te-131m	NP	NP	NP	5.4E-03	3.4E-03	8.8E-03	2.0E+02	1.3E+02	3.3E+02
Te-132	NP	NP	NP	5.6E-04	3.5E-04	9.0E-04	2.1E+01	1.3E+01	3.3E+01

Table 3.0-3 Comparison of Unit 3 and ESP Activity Releases for Failure of Small Lines Carrying Primary Coolant Outside Containment Accident

	ESP Activity Release (Ci)			Unit 3 Activity Release (Ci)			Unit 3 Activity Release (MBq)		
Isotope	**0–2 hr**	**2–8 hr**	**Total**	**0–2 hr**	**2–6 hr**	**Total**	**0–2 hr**	**2–6 hr**	**Total**
I-131	6.13E+00	1.05E+01	1.66E+01	4.1E+00	2.6E+00	6.7E+00	1.5E+05	9.5E+04	2.5E+05
I-132	8.03E+00	7.35E+00	1.54E+01	2.9E+01	1.8E+01	4.6E+01	1.1E+06	6.6E+05	1.7E+06
I-133	1.51E+01	2.35E+01	3.86E+01	2.7E+01	1.7E+01	4.3E+01	9.9E+05	6.1E+05	1.6E+06
I-134	8.78E+00	4.60E+00	1.34E+01	4.5E+01	2.8E+01	7.2E+01	1.7E+06	1.0E+06	2.7E+06
I-135	1.39E+01	1.85E+01	3.24E+01	3.6E+01	2.2E+01	5.8E+01	1.3E+06	8.2E+05	2.1E+06
Cs-134	NP	NP	NP	1.5E-03	9.2E-04	2.4E-03	5.5E+01	3.4E+01	8.9E+01
Cs-136	NP	NP	NP	1.0E-03	6.2E-04	1.6E-03	3.7E+01	2.3E+01	6.0E+01
Cs-137	NP	NP	NP	4.0E-03	2.5E-03	6.4E-03	1.5E+02	9.1E+01	2.4E+02
Ba-140	NP	NP	NP	2.3E-02	1.4E-02	3.7E-02	8.4E+02	5.2E+02	1.4E+03
La-140	NP	NP	NP	2.3E-02	1.4E-02	3.7E-02	8.4E+02	5.2E+02	1.4E+03
Ce-141	NP	NP	NP	1.7E-03	1.1E-03	2.8E-03	6.3E+01	3.9E+01	1.0E+02
Ce-144	NP	NP	NP	1.7E-04	1.1E-04	2.8E-04	6.3E+00	3.9E+00	1.0E+01
Np-239	NP	NP	NP	4.4E-01	2.8E-01	7.2E-01	1.6E+04	1.0E+04	2.7E+04
Total	5.19E+01	6.45E+01	1.16E+02	1.4E+02	8.8E+01	2.3E+02	5.2E+06	3.3E+06	8.5E+06

Notes:
NP – Not present in the ESP
ESBWR accident release activities from ESP Table D-11
Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-18b
Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-18b

Table 3.0-4 Comparison of Unit 3 and ESP Activity Releases for Main Steam Line Break Accident

	ESP Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	**Pre-Existing**	**Equilibrium Activity**	**Equilibrium Activity**	**Iodine Spike Activity**	**Equilibrium Activity**	**Iodine Spike Activity**
Co-58	NP	NP	9.0E-03	9.0E-03	3.03E+02	3.03E+02
Co-60	NP	NP	1.8E-02	1.8E-02	6.6E+02	6.6E+02
Kr-85	6.75E-05	6.75E-05	9.5E-04	9.5E-04	3.5E+01	3.5E+01
Kr-85m	1.72E-02	1.72E-02	2.4E-01	2.4E-01	9.0E+03	9.0E+03
Kr-87	5.74E-02	5.74E-02	7.8E-01	7.8E-01	2.9E+04	2.9E+04
Kr-88	5.74E-02	5.74E-02	7.8E-01	7.8E-01	2.9E+04	2.9E+04
Sr-89	NP	NP	4.1E-02	4.1E-02	1.5E+03	1.5E+03
Sr-90	NP	NP	2.9E-03	2.9E-03	1.1E+02	1.1E+02
Sr-91	NP	NP	1.6E+00	1.6E+00	5.9E+04	5.9E+04
Sr-92	NP	NP	3.6E+00	3.6E+00	1.3E+05	1.3E+05
Y-90	NP	NP	2.9E-03	2.9E-03	1.1E+02	1.1E+02
Y-91	NP	NP	1.7E-02	1.7E-02	6.2E+02	6.2E+02
Y-92	NP	NP	2.2E+00	2.2E+00	8.1E+04	8.1E+04
Y-93	NP	NP	1.6E+00	1.6E+00	5.9E+04	5.9E+04
Zr-95	NP	NP	3.3E-03	3.3E-03	1.2E+02	1.2E+02
Nb-95	NP	NP	3.3E-03	3.3E-03	1.2E+02	1.2E+02
Mo-99	NP	NP	8.1E-01	8.1E-01	3.0E+04	3.0E+04
Tc-99m	NP	NP	8.1E-01	8.1E-01	3.0E+04	3.0E+04
Ru-103	NP	NP	8.2E-03	8.2E-03	3.0E+02	3.0E+02
Ru-106	NP	NP	1.3E-03	1.3E-03	4.7E+01	4.7E+01
Te-129m	NP	NP	1.7E-02	1.7E-02	6.2E+02	6.2E+02
Te-131m	NP	NP	4.0E-02	4.0E-02	1.5E+03	1.5E+03
Te-132	NP	NP	4.1E-03	4.1E-03	1.5E+02	1.5E+02
I-131	1.96E+02	9.79E+00	1.6E+00	3.1E+01	5.7E+04	1.2E+06
I-132	1.86E+03	9.45E+01	1.1E+01	2.2E+02	4.0E+05	8.0E+06

Table 3.0-4 Comparison of Unit 3 and ESP Activity Releases for Main Steam Line Break Accident

	ESP Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	**Pre-Existing**	**Equilibrium Activity**	**Equilibrium Activity**	**Iodine Spike Activity**	**Equilibrium Activity**	**Iodine Spike Activity**
I-133	1.35E+03	6.75E+01	1.0E+01	2.0E+02	3.7E+05	7.5E+06
I-134	3.38E+03	1.72E+02	1.7E+01	3.4E+02	6.2E+05	1.2E+07
I-135	1.92E+03	9.45E+01	1.4E+01	2.7E+02	5.0E+05	1.0E+07
Xe-133	2.46E-02	2.46E-02	3.3E-01	3.3E-01	1.2E+04	1.2E+04
Xe-135	6.75E-02	6.75E-02	9.1E-01	9.1E-01	3.4E+04	3.4E+04
Cs-134	NP	NP	1.1E-02	1.1E-02	4.0E+02	4.0E+02
Cs-136	NP	NP	7.4E-03	7.4E-03	2.7E+02	2.7E+02
Cs-137	NP	NP	2.9E-02	2.9E-02	1.1E+03	1.1E+03
Ba-140	NP	NP	1.7E-01	1.7E-01	6.2E+03	6.2E+03
La-140	NP	NP	1.7E-01	1.7E-01	6.2E+03	6.2E+03
Ce-141	NP	NP	1.3E-02	1.3E-02	4.7E+02	4.7E+02
Ce-144	NP	NP	1.3E-03	1.3E-03	4.7E+01	4.7E+01
Np-239	NP	NP	3.3E+00	3.3E+00	1.2E+05	1.2E+05
Total	8.70E+03	4.39E+02	7.0E+01	1.1E+03	2.6E+06	4.0E+07

Notes:
NP – Not present in the ESP
ESBWR accident release activities from ESP Table D-15
Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-12
Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-12

Table 3.0-5 Comparison of Unit 3 and ESP Activity Releases for Loss-of-Coolant Accident

	ESP Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total
Co-58	2.28E-03	2.22E-02	3.89E-02	4.18E-02	2.61E-02	1.31E-01	8.0E-03	5.9E-02	1.1E-01	1.5E-01	4.3E-01	7.6E-01	2.9E+02	2.2E+03	4.0E+03	5.5E+03	1.6E+04	2.8E+04
Co-60	2.19E-03	2.16E-02	3.76E-02	4.10E-02	2.89E-02	1.31E-01	1.9E-02	1.4E-01	2.6E-01	3.7E-01	1.2E+00	2.0E+00	7.0E+02	5.1E+03	9.2E+03	1.4E+04	4.4E+04	7.3E+04
Kr-85	6.59E+00	3.23E+02	2.72E+03	2.08E+04	5.31E+04	7.70E+04	1.5E+01	3.5E+02	2.5E+03	2.4E+04	3.2E+05	3.5E+05	5.5E+05	1.2E+07	1.7E+07	9.6E+08	1.2E+10	1.3E+10
Kr-85m	1.14E+02	3.01E+03	5.21E+03	8.50E+02	0.00E+00	9.19E+03	2.3E+02	2.9E+03	4.4E+03	7.0E+02	0.0E+00	8.2E+03	8.5E+06	1.1E+08	1.6E+08	2.0E+07	0.0E+00	3.0E+08
Kr-87	1.17E+02	8.60E+02	1.08E+02	0.00E+00	0.00E+00	1.09E+03	2.4E+02	8.6E+02	1.0E+02	0.0E+00	0.0E+00	1.2E+03	9.0E+06	3.3E+07	3.0E+06	0.0E+00	0.0E+00	4.5E+07
Kr-88	2.68E+02	5.12E+03	4.30E+03	1.63E+02	0.00E+00	9.85E+03	5.4E+02	5.0E+03	3.6E+03	1.0E+02	0.0E+00	9.2E+03	2.0E+07	1.8E+08	1.4E+08	0.0E+00	0.0E+00	3.4E+08
Rb-86	1.38E-01	1.00E+00	1.72E+00	1.79E+00	8.25E-01	5.48E+00	2.8E-01	1.8E+00	3.2E+00	4.4E+00	8.3E+00	1.8E+01	1.0E+04	6.6E+04	1.2E+05	1.6E+05	3.0E+05	6.6E+05
Sr-89	3.53E+00	3.46E+01	6.01E+01	6.43E+01	3.88E+01	2.01E+02	8.9E+00	6.5E+01	1.3E+02	1.7E+02	4.5E+02	8.2E+02	3.3E+05	2.4E+06	4.6E+06	6.7E+06	1.6E+07	3.0E+07
Sr-90	3.48E-01	3.42E+00	5.98E+00	6.51E+00	4.63E+00	2.09E+01	1.0E+00	7.4E+00	1.4E+01	2.0E+01	6.8E+01	1.1E+02	3.7E+04	2.7E+05	5.1E+05	7.8E+05	2.3E+06	3.9E+06
Sr-91	3.95E+00	3.06E+01	2.63E+01	5.00E+00	0.00E+00	6.58E+01	1.0E+01	5.8E+01	5.2E+01	1.0E+01	0.0E+00	1.3E+02	3.7E+05	2.1E+06	2.0E+06	4.0E+05	0.0E+00	4.9E+06
Sr-92	3.18E+00	1.45E+01	2.88E+00	1.25E-01	0.00E+00	2.06E+01	8.3E+00	2.8E+01	5.0E+00	1.0E+00	0.0E+00	4.2E+01	3.1E+05	9.9E+05	2.0E+05	0.0E+00	0.0E+00	1.5E+06
Y-90	6.34E-03	1.70E-01	9.06E-01	2.51E+00	4.25E+00	7.84E+00	1.6E-02	3.6E-01	2.1E+00	8.5E+00	5.9E+01	7.0E+01	6.0E+02	1.3E+04	7.8E+04	3.0E+05	2.2E+06	2.6E+06
Y-91	4.59E-02	4.70E-01	8.96E-01	1.03E+00	6.38E-01	3.08E+00	1.2E-01	8.8E-01	1.8E+00	2.8E+00	7.4E+00	1.3E+01	4.3E+03	3.3E+04	7.3E+04	1.0E+05	2.7E+05	4.8E+05
Y-92	4.89E-01	1.01E+01	8.31E+00	3.75E-01	0.00E+00	1.93E+01	9.7E-01	1.8E+01	1.7E+01	1.0E+00	0.0E+00	3.7E+01	3.6E+04	6.8E+05	5.8E+05	1.0E+05	0.0E+00	1.4E+06
Y-93	4.94E-02	3.87E-01	3.45E-01	7.25E-02	0.00E+00	8.54E-01	1.3E-01	7.4E-01	7.3E-01	1.0E-01	0.0E+00	1.7E+00	4.7E+03	2.7E+04	2.6E+04	6.0E+03	0.0E+00	6.4E+04
Zr-95	6.39E-02	6.26E-01	1.09E+00	1.18E+00	7.25E-01	3.68E+00	1.7E-01	1.2E+00	2.3E+00	3.3E+00	9.0E+00	1.6E+01	6.3E+03	4.6E+04	8.8E+04	1.2E+05	3.3E+05	5.9E+05
Zr-97	6.16E-02	5.28E-01	6.10E-01	2.25E-01	0.00E+00	1.43E+00	1.6E-01	1.0E+00	1.3E+00	6.0E-01	0.0E+00	3.1E+00	6.1E+03	3.9E+04	4.9E+04	1.6E+04	1.0E+04	1.2E+05
Nb-95	6.43E-02	6.30E-01	1.11E+00	1.20E+00	8.25E-01	3.83E+00	1.7E-01	1.2E+00	2.4E+00	3.3E+00	9.9E+00	1.7E+01	6.2E+03	4.6E+04	8.8E+04	1.2E+05	3.9E+05	6.5E+05
Mo-99	8.30E-01	7.86E+00	1.23E+01	9.88E+00	1.00E+00	3.19E+01	2.2E+00	1.6E+01	2.6E+01	2.7E+01	9.0E+00	8.0E+01	8.1E+04	5.8E+05	9.4E+05	1.0E+06	3.0E+05	2.9E+06
Tc-99m	7.46E-01	7.24E+00	1.19E+01	1.01E+01	8.75E-01	3.09E+01	2.0E+00	1.5E+01	2.5E+01	2.8E+01	9.0E+00	7.9E+01	7.5E+04	5.5E+05	9.8E+05	1.0E+06	3.0E+05	2.9E+06
Ru-103	6.66E-01	6.52E+00	1.13E+01	1.21E+01	6.88E+00	3.75E+01	1.8E+00	1.3E+01	2.5E+01	3.5E+01	8.5E+01	1.6E+02	6.7E+04	4.9E+05	9.4E+05	1.3E+06	3.2E+06	6.0E+06
Ru-105	3.48E-01	2.09E+00	8.88E-01	3.75E-02	0.00E+00	3.36E+00	1.0E+00	4.4E+00	2.0E+00	1.0E-01	0.0E+00	7.5E+00	3.7E+04	1.6E+05	7.0E+04	1.0E+04	0.0E+00	2.8E+05
Ru-106	2.33E-01	2.28E+00	3.99E+00	4.34E+00	3.04E+00	1.39E+01	6.9E-01	5.1E+00	9.2E+00	1.4E+01	4.2E+01	7.1E+01	2.5E+04	1.9E+05	3.6E+05	5.3E+05	1.5E+06	2.6E+06
Rh-105	4.05E-01	3.88E+00	5.85E+00	3.74E+00	1.25E-01	1.40E+01	1.1E+00	8.3E+00	1.4E+01	1.0E+01	1.0E+00	3.4E+01	4.2E+04	3.1E+05	4.9E+05	3.6E+05	1.0E+05	1.3E+06
Sb-127	9.09E-01	8.69E+00	1.40E+01	1.23E+01	1.75E+00	3.76E+01	2.5E+00	1.8E+01	3.2E+01	3.5E+01	1.3E+01	1.0E+02	9.3E+04	6.7E+05	1.1E+06	1.3E+06	7.0E+05	3.9E+06
Sb-129	2.18E+00	1.30E+01	5.25E+00	1.25E-01	0.00E+00	2.05E+01	6.0E+00	2.6E+01	1.1E+01	1.0E+00	0.0E+00	4.4E+01	2.2E+05	9.8E+05	4.0E+05	0.0E+00	0.0E+00	1.6E+06
Te-127	9.29E-01	8.96E+00	1.49E+01	1.39E+01	3.13E+00	4.18E+01	2.5E+00	1.9E+01	3.3E+01	3.9E+01	3.7E+01	1.3E+02	9.3E+04	6.8E+05	1.2E+06	1.5E+06	1.3E+06	4.8E+06
Te-127m	1.22E-01	1.20E+00	2.09E+00	2.29E+00	1.54E+00	7.24E+00	3.4E-01	2.5E+00	4.8E+00	6.4E+00	2.1E+01	3.5E+01	1.3E+04	9.7E+04	1.7E+05	2.5E+05	7.7E+05	1.3E+06
Te-129	2.41E+00	1.62E+01	1.15E+01	6.75E+00	3.50E+00	4.04E+01	6.6E+00	3.3E+01	2.3E+01	1.9E+01	4.6E+01	1.3E+02	2.4E+05	1.3E+06	9.0E+05	7.0E+05	1.6E+06	4.7E+06

Table 3.0-5 Comparison of Unit 3 and ESP Activity Releases for Loss-of-Coolant Accident *(continued)*

	ESP Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total
Te-129m	4.09E-01	4.02E+00	6.98E+00	7.35E+00	4.13E+00	2.29E+01	1.1E+00	8.2E+00	1.6E+01	2.1E+01	5.1E+01	9.7E+01	4.1E+04	3.0E+05	5.8E+05	7.8E+05	1.9E+06	3.6E+06
Te-131m	1.22E+00	1.11E+01	1.53E+01	8.75E+00	2.50E-01	3.66E+01	3.3E+00	2.3E+01	3.3E+01	2.3E+01	2.0E+00	8.4E+01	1.2E+05	8.3E+05	1.3E+06	8.0E+05	1.0E+05	3.1E+06
Te-132	1.24E+01	1.19E+02	1.88E+02	1.59E+02	1.88E+01	4.96E+02	3.3E+01	2.4E+02	4.0E+02	4.3E+02	2.0E+02	1.3E+03	1.2E+06	8.7E+06	1.5E+07	1.6E+07	7.0E+06	4.8E+07
I-131	6.66E+01	5.13E+02	9.33E+02	1.44E+03	7.00E+02	3.65E+03	1.5E+02	9.5E+02	1.7E+03	2.9E+03	5.3E+03	1.1E+04	5.4E+06	3.5E+07	7.0E+07	1.0E+08	2.1E+08	4.2E+08
I-132	7.88E+01	3.44E+02	2.45E+02	1.89E+02	2.25E+01	8.79E+02	1.9E+02	6.6E+02	5.5E+02	5.0E+02	3.0E+02	2.2E+03	6.9E+06	2.5E+07	1.9E+07	2.0E+07	1.1E+07	8.2E+07
I-133	1.31E+02	9.10E+02	1.22E+03	7.63E+02	1.25E+01	3.04E+03	2.8E+02	1.6E+03	2.3E+03	1.4E+03	1.0E+02	5.7E+03	1.1E+07	6.1E+07	8.8E+07	5.0E+07	0.0E+00	2.1E+08
I-134	4.96E+01	5.10E+01	3.75E-01	0.00E+00	0.00E+00	1.01E+02	1.1E+02	9.0E+01	1.0E+01	0.0E+00	0.0E+00	2.1E+02	4.2E+06	3.4E+06	0.0E+00	0.0E+00	0.0E+00	7.6E+06
I-135	1.11E+02	6.07E+02	4.16E+02	5.38E+01	0.00E+00	1.19E+03	2.4E+02	1.1E+03	8.0E+02	1.0E+02	0.0E+00	2.2E+03	9.0E+06	4.1E+07	2.9E+07	3.0E+06	0.0E+00	8.2E+07
Xe-133	1.08E+03	5.19E+04	4.08E+05	2.51E+06	1.20E+06	4.18E+06	2.2E+03	5.0E+04	3.5E+05	2.5E+06	8.1E+06	1.1E+07	8.1E+07	1.8E+09	1.3E+10	9.5E+10	2.8E+11	3.9E+11
Xe-135	3.68E+02	1.40E+04	5.13E+04	3.80E+04	0.00E+00	1.04E+05	8.2E+02	1.5E+04	4.9E+04	3.5E+04	0.0E+00	1.0E+05	3.1E+07	5.6E+08	1.8E+09	1.4E+09	0.0E+00	3.8E+09
Cs-134	1.16E+01	8.50E+01	1.48E+02	1.63E+02	1.14E+02	5.21E+02	2.7E+01	1.7E+02	3.1E+02	4.5E+02	1.3E+03	2.3E+03	9.9E+05	6.2E+06	1.2E+07	1.6E+07	5.0E+07	8.5E+07
Cs-136	4.03E+00	2.92E+01	5.00E+01	5.05E+01	2.00E+01	1.54E+02	8.7E+00	5.4E+01	9.7E+01	1.3E+02	2.1E+02	5.0E+02	3.2E+05	2.0E+06	3.7E+06	5.0E+06	7.0E+06	1.8E+07
Cs-137	7.54E+00	5.52E+01	9.60E+01	1.05E+02	7.50E+01	3.39E+02	1.7E+01	1.0E+02	2.1E+02	2.8E+02	8.9E+02	1.5E+03	6.3E+05	4.0E+06	7.4E+06	1.0E+07	3.2E+07	5.4E+07
Ba-139	2.96E+00	7.50E+00	3.00E-01	0.00E+00	0.00E+00	1.08E+01	8.2E+00	1.5E+01	0.0E+00	0.0E+00	0.0E+00	2.3E+01	3.0E+05	5.4E+05	2.0E+04	0.0E+00	0.0E+00	8.6E+05
Ba-140	6.26E+00	6.10E+01	1.04E+02	1.06E+02	4.00E+01	3.18E+02	1.6E+01	1.2E+02	2.2E+02	2.9E+02	4.5E+02	1.1E+03	6.1E+05	4.5E+06	7.9E+06	1.1E+07	1.7E+07	4.1E+07
La-140	1.40E-01	4.41E+00	2.37E+01	5.83E+01	4.35E+01	1.30E+02	3.2E-01	8.5E+00	5.0E+01	1.7E+02	5.1E+02	7.4E+02	1.2E+04	3.2E+05	1.9E+06	6.3E+06	2.0E+07	2.8E+07
La-141	4.50E-02	2.56E-01	9.13E-02	2.50E-03	0.00E+00	3.95E-01	1.2E-01	5.0E-01	1.9E-01	1.0E-02	0.0E+00	8.2E-01	4.4E+03	1.9E+04	7.0E+03	0.0E+00	0.0E+00	3.0E+04
La-142	2.84E-02	8.09E-02	4.50E-03	0.00E+00	0.00E+00	1.14E-01	7.8E-02	1.5E-01	1.0E-02	0.0E+00	0.0E+00	2.4E-01	2.9E+03	5.8E+03	3.0E+02	0.0E+00	0.0E+00	9.0E+03
Ce-141	1.49E-01	1.46E+00	2.54E+00	2.69E+00	1.46E+00	8.30E+00	3.9E-01	2.9E+00	5.3E+00	7.4E+00	1.8E+01	3.4E+01	1.4E+04	1.1E+05	2.0E+05	2.8E+05	7.0E+05	1.3E+06
Ce-143	1.35E-01	1.23E+00	1.75E+00	1.05E+00	2.50E-02	4.19E+00	3.5E-01	2.5E+00	3.6E+00	2.7E+00	3.0E-01	9.4E+00	1.3E+04	8.7E+04	1.4E+05	1.0E+05	1.0E+04	3.5E+05
Ce-144	1.21E-01	1.19E+00	2.08E+00	2.26E+00	1.55E+00	7.20E+00	3.2E-01	2.4E+00	4.5E+00	6.8E+00	1.9E+01	3.3E+01	1.2E+04	8.7E+04	1.6E+05	2.4E+05	7.0E+05	1.2E+06
Pr-143	5.46E-02	5.40E-01	9.68E-01	1.06E+00	4.63E-01	3.09E+00	1.4E-01	1.1E+00	2.0E+00	2.9E+00	4.9E+00	1.1E+01	5.2E+03	3.9E+04	7.6E+04	1.1E+05	1.9E+05	4.2E+05
Nd-147	2.38E-02	2.31E-01	3.94E-01	3.95E-01	1.39E-01	1.18E+00	6.3E-02	4.6E-01	8.8E-01	1.0E+00	1.6E+00	4.0E+00	2.3E+03	1.7E+04	3.1E+04	4.1E+04	5.9E+04	1.5E+05
Np-239	1.69E+00	1.59E+01	2.44E+01	1.88E+01	1.38E+00	6.21E+01	4.6E+00	3.2E+01	5.4E+01	4.9E+01	2.0E+01	1.6E+02	1.7E+05	1.2E+06	2.0E+06	1.9E+06	4.0E+05	5.7E+06
Pu-238	2.98E-04	2.93E-03	5.11E-03	5.54E-03	4.00E-03	1.79E-02	9.6E-04	7.0E-03	1.3E-02	1.9E-02	6.0E-02	1.0E-01	3.5E+01	2.7E+02	4.9E+02	7.1E+02	2.2E+03	3.7E+03
Pu-239	3.59E-05	3.53E-04	6.19E-04	6.80E-04	4.75E-04	2.16E-03	1.1E-04	7.8E-04	1.5E-03	2.1E-03	6.5E-03	1.1E-02	3.9E+00	2.9E+01	5.5E+01	8.2E+01	2.5E+02	4.2E+02
Pu-240	4.65E-05	4.56E-04	7.98E-04	8.75E-04	6.13E-04	2.79E-03	1.4E-04	1.1E-03	1.9E-03	2.7E-03	9.2E-03	1.5E-02	5.1E+00	3.8E+01	6.7E+01	1.1E+02	3.2E+02	5.4E+02
Pu-241	1.35E-02	1.33E-01	2.31E-01	2.53E-01	1.78E-01	8.08E-01	4.4E-02	3.3E-01	6.1E-01	9.2E-01	2.7E+00	4.6E+00	1.6E+03	1.2E+04	2.2E+04	3.3E+04	1.0E+05	1.7E+05
Am-241	6.08E-06	5.97E-05	1.06E-04	1.15E-04	9.25E-05	3.79E-04	2.1E-05	1.6E-04	2.9E-04	4.4E-04	1.5E-03	2.4E-03	7.9E-01	5.8E+00	1.1E+01	1.5E+01	5.7E+01	9.0E+01

Table 3.0-5 Comparison of Unit 3 and ESP Activity Releases for Loss-of-Coolant Accident *(continued)*

	ESP Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**
Cm-242	1.43E-03	1.40E-02	2.44E-02	2.65E-02	1.76E-02	8.39E-02	5.0E-03	3.7E-02	6.8E-02	1.0E-01	3.0E-01	5.1E-01	1.9E+02	1.4E+03	2.5E+03	3.7E+03	1.1E+04	1.9E+04
Cm-244	6.91E-05	6.77E-04	1.19E-03	1.29E-03	9.13E-04	4.14E-03	2.6E-04	1.9E-03	3.6E-03	5.2E-03	1.7E-02	2.8E-02	9.7E+00	7.1E+01	1.4E+02	1.9E+02	5.9E+02	1.0E+03
Total	2.46E+03	7.82E+04	4.76E+05	2.58E+06	1.25E+06	4.39E+06	5.2E+03	8.0E+04	4.1E+05	2.6E+06	8.4E+06	1.1E+07	1.9E+08	2.9E+09	1.6E+10	9.8E+10	2.9E+11	4.1E+11

Notes:

ESBWR accident release activities from ESP Table D-18

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-7a

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-7

Table 3.0-6 Activity Releases for ESBWR Cleanup Water Line Break

	ESP Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	0–2 hr	Equilibrium Activity	Pre-Incident Spike	Equilibrium Activity	Pre-Incident Spike
I-131	3.48E+01	4.10E+00	8.21E+01	1.52E+05	3.04E+06
I-132	7.05E+01	2.85E+01	5.71E+02	1.06E+06	2.11E+07
I-133	9.28E+01	2.68E+01	5.35E+02	9.90E+05	1.98E+07
I-134	1.22E+02	4.46E+01	8.92E+02	1.65E+06	3.30E+07
I-135	9.59E+01	3.57E+01	7.14E+02	1.32E+06	2.64E+07
Cs-134	NP	2.95E-02	2.95E-02	1.09E+03	1.09E+03
Cs-136	NP	2.00E-02	2.00E-02	7.39E+02	7.39E+02
Cs-137	NP	7.95E-02	7.95E-02	2.94E+03	2.94E+03
Co-58	NP	2.42E-02	2.42E-02	8.97E+02	8.97E+02
Co-60	NP	4.85E-02	4.85E-02	1.79E+03	1.79E+03
Sr-89	NP	1.11E-01	1.11E-01	4.12E+03	4.12E+03
Sr-90	NP	7.72E-03	7.72E-03	2.86E+02	2.86E+02
Y-90	NP	7.72E-03	7.72E-03	2.86E+02	2.86E+02
Sr-91	NP	4.31E+00	4.31E+00	1.60E+05	1.60E+05
Sr-92	NP	9.76E+00	9.76E+00	3.61E+05	3.61E+05
Y-91	NP	4.54E-02	4.54E-02	1.68E+03	1.68E+03
Y-92	NP	5.90E+00	5.90E+00	2.18E+05	2.18E+05
Y-93	NP	4.31E+00	4.31E+00	1.60E+05	1.60E+05
Zr-95	NP	8.86E-03	8.86E-03	3.28E+02	3.28E+02
Nb-95	NP	8.86E-03	8.86E-03	3.28E+02	3.28E+02
Mo-99	NP	2.20E+00	2.20E+00	8.15E+04	8.15E+04
Tc-99m	NP	2.20E+00	2.20E+00	8.15E+04	8.15E+04
Ru-103	NP	2.23E-02	2.23E-02	8.23E+02	8.23E+02
Ru-106	NP	3.41E-03	3.41E-03	1.26E+02	1.26E+02
Te-129m	NP	4.54E-02	4.54E-02	1.68E+03	1.68E+03
Te-131m	NP	1.09E-01	1.09E-01	4.03E+03	4.03E+03
Te-132	NP	1.11E-02	1.11E-02	4.12E+02	4.12E+02

Table 3.0-6 Activity Releases for ESBWR Cleanup Water Line Break

	ESP Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	0–2 hr	Equilibrium Activity	Pre-Incident Spike	Equilibrium Activity	Pre-Incident Spike
Ba-140	NP	4.54E-01	4.54E-01	1.68E+04	1.68E+04
La-140	NP	4.54E-01	4.54E-01	1.68E+04	1.68E+04
Ce141	NP	3.41E-02	3.41E-02	1.26E+03	1.26E+03
Ce-144	NP	3.41E-03	3.41E-03	1.26E+02	1.26E+02
Np-239	NP	8.86E+00	8.86E+00	3.28E+05	3.28E+05
Total	4.16E+02	1.79E+02	2.83E+03	6.62E+06	1.05E+08

Notes:

NP – Not present in the ESP

ESBWR accident release activities from ESP Table D-22

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-22

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-22

Table 3.0-6a Activity Releases for ESBWR Feedwater System Pipe Break

	ESP Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	0–2 hr	Equilibrium Activity	Pre-incident Spike	Equilibrium Activity	Pre-incident Spike
I-131	4.39E-03	1.08E+01	2.16E+02	3.99E+05	7.97E+06
I-132	4.05E-02	7.50E+01	1.50E+03	2.77E+06	5.55E+07
I-133	2.94E-02	7.03E+01	1.41E+03	2.60E+06	5.20E+07
I-134	7.43E-02	1.17E+02	2.34E+03	4.33E+06	8.67E+07
I-135	4.05E-02	9.37E+01	1.87E+03	3.47E+06	6.93E+07
Cs-134	NP	7.75E-02	7.75E-02	2.87E+03	2.87E+03
Cs-136	NP	5.25E-02	5.25E-02	1.94E+03	1.94E+03
Cs-137	NP	2.09E-01	2.09E-01	7.72E+03	7.72E+03
Co-58	NP	6.37E-02	6.37E-02	2.36E+03	2.36E+03
Co-60	NP	1.27E-01	1.27E-01	4.71E+03	4.71E+03
Sr-89	NP	2.92E-01	2.92E-01	1.08E+04	1.08E+04
Sr-90	NP	2.03E-02	2.03E-02	7.50E+02	7.50E+02
Y-90	NP	2.03E-02	2.03E-02	7.50E+02	7.50E+02
Sr-91	NP	1.13E+01	1.13E+01	4.19E+05	4.19E+05
Sr-92	NP	2.56E+01	2.56E+01	9.49E+05	9.49E+05
Y-91	NP	1.19E-01	1.19E-01	4.41E+03	4.41E+03
Y-92	NP	1.55E+01	1.55E+01	5.74E+05	5.74E+05
Y-93	NP	1.13E+01	1.13E+01	4.19E+05	4.19E+05
Zr-95	NP	2.33E-02	2.33E-02	8.61E+02	8.61E+02
Nb-95	NP	2.33E-02	2.33E-02	8.61E+02	8.61E+02
Mo-99	NP	5.78E+00	5.78E+00	2.14E+05	2.14E+05
Tc-99m	NP	5.78E+00	5.78E+00	2.14E+05	2.14E+05
Ru-103	NP	5.84E-02	5.84E-02	2.16E+03	2.16E+03
Ru-106	NP	8.94E-03	8.94E-03	3.31E+02	3.31E+02
Te-129m	NP	1.19E-01	1.19E-01	4.41E+03	4.41E+03
Te-131m	NP	2.86E-01	2.86E-01	1.06E+04	1.06E+04
Te-132	NP	2.92E-02	2.92E-02	1.08E+03	1.08E+03

Table 3.0-6a Activity Releases for ESBWR Feedwater System Pipe Break

	ESP Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	**0–2 hr**	**Equilibrium Activity**	**Pre-incident Spike**	**Equilibrium Activity**	**Pre-incident Spike**
Ba-140	NP	1.19E+00	1.19E+00	4.41E+04	4.41E+04
La-140	NP	1.19E+00	1.19E+00	4.41E+04	4.41E+04
Ce141	NP	8.94E-02	8.94E-02	3.31E+03	3.31E+03
Ce-144	NP	8.94E-03	8.94E-03	3.31E+02	3.31E+02
Np-239	NP	2.33E+01	2.33E+01	8.61E+05	8.61E+05
Total	1.89E-01	4.69E+02	7.44E+03	1.74E+07	2.75E+08

Notes:
NP – Not present in the ESP
ESBWR accident release activities from ESP Table D-7
Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-15
Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-15

Table 3.0-7 Comparison of Unit 3 and ESP Liquid Effluent Release Activities

Isotope	ESP Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
H-3	8.5E+02	1.4E+01	5.18E+05
C-14	4.4E-04	NP	NP
Na-24	3.5E-03	4.2E-03	1.55E+02
P-32	6.6E-04	3.5E-04	1.30E+01
Cr-51	2.1E-02	1.1E-02	4.07E+02
Mn-54	2.8E-03	1.3E-04	4.81E+00
Mn-56	4.2E-03	1.0E-03	3.70E+01
Fe-55	6.4E-03	1.9E-03	7.03E+01
Fe-59	2.0E-04	6.0E-05	2.22E+00
Co-56	5.7E-03	NP	NP
Co-57	7.9E-05	NP	NP
Co-58	3.4E-03	3.7E-04	1.37E+01
Co-60	1.0E-02	7.5E-04	2.78E+01
Ni-63	1.5E-04	NP	NP
Cu-64	8.2E-03	1.0E-02	3.70E+02
Zn-65	7.5E-04	3.7E-04	1.37E+01
Zn-69m	6.0E-04	7.5E-04	2.78E+01
Br-83	7.5E-05	1.0E-04	3.70E+00
Br-84	2.0E-05	NP	NP
Rb-88	2.7E-04	NP	NP
Rb-89	4.8E-05	NP	NP
Sr-89	3.6E-04	1.9E-04	7.03E+00
Sr-90	3.8E-05	1.0E-05	3.70E-01
Sr-91	9.8E-04	9.5E-04	3.52E+01
Sr-92	8.8E-04	2.3E-04	8.51E+00
Y-90	3.4E-06	NP	NP

Table 3.0-7 Comparison of Unit 3 and ESP Liquid Effluent Release Activities

Isotope	ESP Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
Y-91m	1.0E-05	NP	NP
Y-91	2.4E-04	1.2E-04	4.44E+00
Y-92	6.6E-04	8.7E-04	3.22E+01
Y-93	9.8E-04	1.0E-03	3.70E+01
Zr-95	1.0E-03	1.0E-05	3.70E-01
Nb-95	1.9E-03	1.0E-05	3.70E-01
Mo-99	3.9E-03	2.5E-03	9.25E+01
Tc-99m	5.1E-03	4.6E-03	1.70E+02
Ru-103	4.9E-03	4.0E-05	1.48E+00
Ru-105	1.0E-04	1.3E-04	4.81E+00
Ru-106	7.4E-02	NP	NP
Rh-103m	4.9E-03	NP	NP
Rh-106	7.4E-02	NP	NP
Ag-110m	1.1E-03	NP	NP
Ag-110	1.4E-04	NP	NP
Sb-124	6.8E-04	NP	NP
Te-129m	1.4E-04	7.0E-05	2.59E+00
Te-129	1.5E-04	NP	NP
Te-131m	1.0E-04	8.0E-05	2.96E+00
Te-131	3.0E-05	NP	NP
Te-132	2.4E-04	1.0E-05	3.70E-01
I-131	1.4E-02	6.2E-03	2.29E+02
I-132	2.8E-03	9.3E-04	3.44E+01
I-133	2.4E-02	3.0E-02	1.11E+03
I-134	1.9E-03	4.0E-05	1.48E+00
I-135	8.2E-03	7.1E-03	2.63E+02

Table 3.0-7 Comparison of Unit 3 and ESP Liquid Effluent Release Activities

Isotope	ESP Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
Cs-134	9.9E-03	5.7E-04	2.11E+01
Cs-136	1.2E-03	3.5E-04	1.30E+01
Cs-137	1.3E-02	1.5E-03	5.55E+01
Cs-138	2.1E-04	NP	NP
Ba-137m	1.2E-02	NP	NP
Ba-139	2.5E-05	3.0E-05	1.11E+00
Ba-140	5.5E-03	6.9E-04	2.55E+01
La-140	7.4E-03	NP	NP
La-142	2.5E-05	2.0E-05	7.40E+01
Ce-141	1.3E-04	6.0E-05	2.22E+00
Ce-143	1.9E-04	3.0E-05	1.11E+00
Ce-144	3.2E-03	NP	NP
Pr-143	1.4E-04	7.0E-05	2.59E+00
Pr-144	3.2E-03	NP	NP
W-187	2.1E-04	2.0E-04	7.40E+00
Np-239	1.4E-02	9.3E-03	3.44E+02
Total w/o H-3	3.7E-01	9.9E-02	3.66E+03
Total w/ H-3	8.5E+02	1.4E+01	5.22E+05

Notes:

NP – Not present; Note: Isotopes with liquid effluent release activity greater than the ESP activity are represented in bold face

ESBWR accident release activities from ESP Table D-23

Unit 3-specific normal operation liquid effluent release activities in the unit of mega-becquerel (MBq) from FSAR Table 12.2-19bR

Table 3.0-8 Fuel Handling Accident

	ESP Activity Release (Ci)	Unit 3 Activity Release (Ci)
Isotope	**0-2 hr**	**0-2 hr**
Kr-85m	2.68E-03	9.96E+0
Kr-85	1.10E+03	4.98E+02
Kr-87	**NP**	1.07E-02
Kr-88	**NP**	2.85E+01
Xe-131m	5.36E+02	**NP**
Xe-133m	1.29E+03	**NP**
Xe-133	6.94E+04	3.23E+04
Xe-135m	4.37E-01	**NP**
Xe-135	1.32E+02	2.01E+03
I-130	3.52E-02	**NP**
I-131	2.90E+02	1.37E+02
I-132	1.54E+02	7.01E-02
I-133	1.91E+01	8.21E+01
I-134	**NP**	5.24E-07
I-135	1.36E-02	1.28E+01
Total	7.29E+04	3.52E+04

NP = Not present.
ESP accident release activities from ESP Table D-19.
Unit 3-specific accident release activities from DCD Table 15.4-3a.

3.1 External Appearance and Plant Layout

Information regarding external appearance and plant layout is provided in ESP-ER Section 3.1. Supplemental information is provided below.

The design selected for Unit 3 is an ESBWR. A general description of the ESBWR design is provided in FSAR Section 1.1 and FSAR Section 1.2, and the site layout is provided in Figure 1.1-1 and Figure 1.1-2. Table 3.0-2 lists the ESP plant parameter values that were identified in ESP Table D-1 and compares them to the corresponding Unit 3 design characteristics.

In accordance with the commitment in ESP-ER Section 5.8.1.5, a visual impact evaluation has been conducted to assess the aesthetic impact of the external appearance of Unit 3. Section 5.8 describes the results of this evaluation and provides artist renderings of the site with Unit 3.

3.2 Reactor Power Conversion System

The Unit 3 reactor power conversion system consists of an ESBWR, a turbine-generator set, and its auxiliaries. As shown in Table 3.0-2, design characteristics of the Unit 3 reactor power conversion system fall within the ESP plant parameters identified in ESP Table D-1. For further information on the reactor power conversion system, refer to FSAR Chapters 4, 5, 6, and Chapter 10.

3.3 Plant Water Use

Information for this section is provided in ESP-ER Section 3.3 and FEIS Section 3.2.1. Although ESP-ER Section 3.3 described several water treatment systems for the operation of new units, specific chemicals to be used in water treatment were not known. FEIS Section 5.3.3 identified the need to provide the chemical constituents of effluents in waste streams, other than those in cooling tower blowdown. To provide the information requested in FEIS Section 5.3.3, water treatment systems and associated chemical additives for Unit 3 are described in the following subsections.

3.3.1 Water Consumption

The current water consumption associated with proposed Unit 3 is bounded by that reported in the ESP-ER. ESP-ER Table 3.3-1 also provides discharge rates for various systems, including the sanitary waste system. Water release points and quantities are described in Section 3.6 and in ESP-ER Section 3.3.1, respectively. The ESP-ER indicated that the existing sanitary waste system would be modified to accommodate the sanitary waste requirements of the new units. However, it has now been determined that a separate sanitary waste system will be provided for new Unit 3. A description of the Unit 3 sanitary waste system is provided in Section 3.6.2.

3.3.2 Water Treatment

Several water treatment systems will be used in Unit 3 operations. The water treatment systems and associated chemical additives are described in the following sections.

3.3.2.1 **Raw Water**

Make-up water necessary for the Unit 3 cooling towers will be treated for biofouling, scaling, and suspended matter, with acceptable biocides, anti-scalants, and dispersants, respectively.

Each chemical treatment feed system consists of a tank or totes, metering pumps and the necessary associated strainers, pulsation dampeners, piping, valves, instrumentation and controls. Chemical injection points are identified in Table 3.3-1, and the treatment chemicals and their quantities are described below.

The primary biocide to be used for circulating water and plant service water is commercially available 12.5 percent sodium hypochlorite, which will be injected directly into the cooling tower basins and will be equivalent to 120g Cl_2 per liter. A chlorination dosage of 2 ppm chlorine for approximately 30 minutes, three times a day, will maintain a residual of 0.5 ppm Cl_2. This dose is based on the respective system water flow rates.

The anti-scalant to be used for circulating water and plant service water is ChemTreat CL2010 (or equivalent) at a continuous dose rate of 10 ppm neat (i.e., undiluted). The dose is based on the cooling tower blowdown flow rate.

The dispersant to be used for circulating water and plant service water is ChemTreat CL1355 (or equivalent) at a continuous dose rate of 5 ppm neat. The dose is based on the cooling tower blowdown flow rate.

Sodium hypochlorite injection for station water chlorination will be injected into pump discharge piping and is based on a continuous dose of 0.5 ppm Cl_2. The dose is based on plant cooling tower make-up flow and firewater flow, with the dosage adjusted seasonally as required.

Sodium bisulfite will be used for circulating water and plant service water dechlorination. It will be injected at a dose based on neutralizing residual combined chlorine of 0.5 ppm as Cl_2 to at or below the chlorine concentration limits set by the Virginia Pollutant Discharge Elimination System (VPDES) permit. The dose rate will be approximately 120 percent of the stoichiometric rate required to neutralize the residual chlorine in the circulating water and plant service water cooling tower blowdown. This is sufficient to dechlorinate both circulating water and plant service water cooling tower blowdown flows.

Sodium bromide (40% wt) will be used as a secondary biocide, if required. It will be injected at a 6:1 to 10:1 hypochlorite to bromide ratio. Sodium bromide injection will occur simultaneously with sodium hypochlorite injection (approximately 30 minutes, three times a day) as needed.

Provisions are also included to inject, as an option, a non-oxidizing biocide (Nalco's H-130 or equivalent). The proposed dose rate is 15 to 25 ppm neat, based on circulating and plant service water system volume. The injection will be in a 20-to-40-minute period as needed from once per week to once per month.

Raw water from the North Anna Reservoir will be treated by filtration in the station water system and used to provide make-up for demineralized water, fire protection, and miscellaneous station water users. Prior to filtration, the station water system will be treated with hydrogen peroxide, alum as a coagulant and sodium bicarbonate for final pH adjustment, or similar treatment.

3.3.2.2 **Make-up Water**

Make-up water from the North Anna Reservoir for systems other than circulating water and service water will be treated by a process that includes filtration in the station water system followed by processing by one or more treatment methods such as activated carbon filters, reverse osmosis (RO), and mixed bed demineralizers, which will result in highly purified water for use in various plant systems. In addition to the processing described above, the demineralized water system will be treated with an anti-scalant just prior to the RO membranes and with sodium hydroxide between the first and second passes of the RO membranes to improve permeate water quality. Once purified, the make-up water will be directed to various plant systems and services such as condensate and the auxiliary boiler systems.

3.3.2.3 **Condensate System**

Treated condensate water serves as the source of feedwater. Condensate-grade water also serves as the heat transfer media for residual heat removal from primary systems and for the chilled water subsystem. For the existing units, component cooling water is treated by the chemical addition of chromates for corrosion inhibition and pH control. For Unit 3, the component cooling water and chilled water systems will be provided with a chemical feed tank for corrosion inhibitor addition. A specific corrosion inhibitor has not been selected at this time. Water for the chilled water subsystem may need additional treatment depending on the piping materials used.

3.3.2.4 **Domestic Water System**

The domestic water system will provide a safe, state-permitted potable water supply. The Unit 3 domestic water system will be supplied from groundwater wells using hydro-pneumatic tanks and compressors, for pressure maintenance, and a distribution system. Water treatment will be provided through filtration and disinfection, as needed.

Table 3.3-1 Unit 3 Chemical Injection Points

Service	Injection Point
Circulating water sodium hypochlorite feed	Circulating water cooling tower basin
Circulating water anti-scalant feed	Circulating water cooling tower basin or circulating water pump intake bay
Circulating water dispersant feed	Circulating water cooling tower basin or circulating water pump intake bay
Circulating water sodium bromide feed (if required)	Circulating water cooling tower basin
Circulating water non-oxidizing biocide feed (optional)	Circulating water cooling tower basin
Plant service water sodium hypochlorite feed	Plant service water cooling tower basin
Plant service water anti-scalant feed	Plant service water cooling tower basin or essential plant water pump intake bay
Plant service water dispersant feed	Plant service water cooling tower basin or plant service water pump intake bay
Plant service water sodium bromide feed (if required)	Plant service water cooling tower basin
Plant service water non-oxidizing biocide feed (optional)	Plant service water cooling tower basin
Plant intake sodium hypochlorite feed	Common line in Station Water (Plant Cooling Tower Makeup) pump discharge
Firewater sodium hypochlorite injection	Secondary firewater pump discharge
Circulating water cooling tower blowdown sodium bisulfite feed	Circulating water cooling tower blowdown
Reverse Osmosis anti-scalant injection	Upstream of RO membrane
Sodium hydroxide	Between 1st and 2nd passes RO membranes
Hydrogen peroxide, alum (coagulant) & sodium bicarbonate (pH adjustment)	Upstream of station water (pretreated water supply system) filters
Circulating water corrosion inhibitor feed	Circulating water cooling tower basin or circulating water pump intake bay
Plant service water corrosion inhibitor feed	Plant service water cooling tower basin or plant service water pump intake bay
Plant service water cooling tower blowdown sodium bisulfite feed	Plant service water cooling tower blowdown

3.4 Cooling System

The Unit 3 cooling system is a closed-cycle, hybrid cooling system, as described in ESP-ER Section 3.4. Table 3.0-2 compares ESP design parameters against the corresponding design characteristics of the Unit 3 cooling system. Section 5.10.1 provides information addressing the mitigating actions based on the results of the IFIM study.

3.5 Radioactive Waste Management System

Information regarding the radioactive waste management system is provided in ESP-ER Section 3.5 and FEIS Section 3.2.3. Supplemental information is provided below.

Descriptions of the liquid, gaseous, and solid radioactive waste management systems are provided in FSAR Section 11.2, Section 11.3, and Section 11.4, respectively.

Liquid effluent release activities are provided in Table 5.4-1. Liquid pathway doses are evaluated in Section 5.4.2.1.

Gaseous effluent release activities are provided in Table 5.4-3. Gaseous pathway doses are evaluated in Section 5.4.2.2.

The total predicted yearly activity and yearly generated volume of solid radwaste are provided in Table 3.0-2.

3.6 Nonradioactive Waste Systems

Information for this section is provided in ESP-ER Section 3.6 and FEIS Section 3.2.4. At the time of the ESP-ER, the sanitary waste system for Units 1 and 2 was being evaluated for modification to accommodate Unit 3 sanitary waste requirements. It was subsequently determined that a separate sanitary waste system will be designed for Unit 3. A discussion of this separate sanitary waste system is provided in Section 3.6.2.

FEIS Section 5.3.3 states that the applicant would need to provide information regarding chemical effluents at the time of the COL application.

3.6.1 Effluents Containing Chemicals or Biocides

Proper treatment of lake water will be required for use in various plant systems such as: circulating water, plant service water, station water and demineralized water. Waste effluents from these systems would include circulating water and service water system blowdown, station and demineralized water system filter backwashes, demineralized water reverse osmosis reject and nonradioactive drains throughout the station. Unit 3 effluent streams will be directed to the existing discharge canal where it would mix with circulating water from Units 1 and 2, prior to discharge to the WHTF.

Unit 3 effluent streams will contain some low-level chemicals and/or biocides used for water treatment. Section 3.3 identifies systems that use such chemicals, a description of those chemicals and their injection points. None of the chemicals and/or biocides used for water treatment in Unit 3 will contain any of the "126 priority pollutants" listed in 40 CFR 423, Appendix A (Reference 1). Furthermore, their interaction within the plant systems would not create any by-products that would contain any of these pollutants. However, the effluent streams from Unit 3 will include some of the "126 priority pollutants" due to the fact that they are already present in the lake water. Table 2.3-1 provides a list of the constituents that have been measured in lake water. This table also includes the Reported Level of the constituent concentration in the lake, the Virginia Surface Water Quality Criteria (VSWQC) and the Detection Level of various constituents. In addition to the "126 priority pollutants," this table also includes other constituents and characteristics listed on NPDES Form 2C for which sampling is currently performed.

An analysis was performed using Lake Anna water chemistry data to estimate the constituent levels of the projected effluent streams from Unit 3 and to predict if the new effluents would comply with the existing VPDES permit for Units 1 and 2 (Reference 2). As stated above, these effluent streams will contain all of the constituents already present in the lake water. The analysis used the maximum value for each constituent for conservatism. The Unit 3 effluent is primarily composed of cooling water blowdown streams from the circulating water and service water systems. Constituent concentrations will increase in these two effluent streams due to evaporation losses from these cooling systems. Consequently the potential impact of these effluent streams was estimated by increasing measured lake water concentrations, by factors of four and nine (as separate cases), to account for evaporative loss. The combined blowdown discharge was then evaluated to account for the dilution provided by three different circulating water flow conditions for Units 1 and 2 operation (i.e., all eight circulating water pumps running, two pumps running, or only one pump running).

The results of the analysis demonstrate that for all of the case-condition combinations stated above, the constituent concentrations present at the end of the discharge canal will be less than or equal to the existing Virginia Surface Water Quality Criteria for all but two constituents: copper and tributyltin (TBT).

Both of these constituents, on at least one occasion during the sampling period, have been measured in Lake Anna at concentrations equal to or greater than the current Virginia Surface Water Quality Criteria. The table below shows the maximum and average reported lake water concentrations in comparison to the surface water quality criteria. The table also shows that, based on the maximum concentration and an assumed dilution, the projected concentrations are only approximately 6 to 7 percent above that in the lake. Finally, the table shows that if the average readings were used in place of the maximums, the projected concentrations would be below the surface water quality criteria.

The presence of elevated levels of copper is explained by past mining operations that heavily impacted Contrary Creek, which flows into Lake Anna above the North Anna Power Station (see

ESP-ER Section 5.3.2.2.2.b). Furthermore, copper is also a key ingredient in current boat hull paints to prevent/retard biofouling of boat hulls. This copper-based paint is designed to be ablative, thus requiring recoating each year. TBT was also used as a biocide in paint for marine application. Although TBT has been restricted for use in this application and the use of marine paints containing TBT is now regulated under the Organotin Antifouling Paint Control Act of 1988, residual amounts of TBT still remain in water bodies such as Lake Anna. The presence of both of these constituents is unrelated to the operation of Units 1 and 2, and Unit 3 would not contribute further. Additionally the increase in concentrations of these constituents in the discharge to the WHTF attributable to the operation of Unit 3 would be essentially immeasurable using current VDEQ-approved analytical methods.

Nominal amounts of non-priority pollutants may be generated from corrosion and wear of plant piping and equipment, some of which could appear in effluent streams. These include three constituents described in the ESP-ER, i.e., oil and grease, total suspended solids and iron. As indicated in Table 2.3-1, these constituents do not have Virginia Surface Water Quality Criteria. For iron, the only existing numeric criterion is for the protection of public water supplies, and Lake Anna is not a designated public water supply. Although these constituents have no VSWQC, they were included in the waste stream analysis. The results indicate that once mixed with the assumed discharge from Units 1 and 2, oil & grease and iron concentrations are much less than 1 mg/L (ppm) and total suspended solids is approximately 5 mg/L (ppm).

Dominion analyzes station discharge for these constituents and characteristics as required by the VPDES permit for Units 1 and 2. Similar sampling and analyses will be performed in accordance with the VPDES permit for Unit 3. See Section 3.3 for chemicals that would be used in the systems requiring pre-treatment along with the proposed injection points for those chemicals.

The potable water system will be supplied from onsite wells. Currently, water from onsite wells is not treated; however, it can be treated if sampling indicates treatment is necessary.

Table 3.6-1 Copper and Tributyltin Concentrations vs. Water Quality Criteria

Constituent Name (See Note 1)	Virginia Surface Water Quality Criteria (VSWQC)	Reported Level in Lake (Max. Reading)	Projected Concentration in WHTF (Max. Reading) (See Note 2)	Reported Level in Lake (Avg.)	Projected Concentration in WHTF (Avg. Reading) (See Note 2)
Copper	0.0027	0.0030	0.0032	0.0014	0.0015
Tributyltin	0000063	0.000063	0.000067	0.000013	0.000014

Notes:
1. All values are in mg/L (ppm).
2. Based on 4 cycles of concentration with one Unit 1/2 Circulating Water Pump operating considering the reported levels in the lake.

3.6.2 Sanitary System Effluents

A sanitary waste system would be maintained onsite during the construction and operation of Unit 3, with effluents in compliance with acceptable industry design standards, the Clean Water Act (CWA), the state regulatory authority through the VPDES permit and 9 VAC 25-790, Sewage Collection & Treatment Regulations, Commonwealth of Virginia, State Water Control Board. (Reference 3)

The waste treatment system would be permanent, with no wastes handled or processed through a municipal system. Until the permanent sanitary waste treatment facility is functional either during construction or for operation of Unit 3 or as needed during peak construction or outage support activities, additional sewage treatment capacity and approved supplemental means of handling sanitary wastes would be employed. Typically, this supplemental means would be portable sanitary facilities. These facilities could include a centralized restroom and hand-wash trailer(s) in addition to single restroom units located throughout the site as necessary. The wastes collected in these temporary facilities would be pumped out and disposed of by a licensed sanitary waste disposal contractor.

The sanitary waste discharge system for Unit 3 would be designed to collect and transfer sanitary water/waste from the potable water and sanitary waste system to the sewage treatment plant. The sewage treatment plant would be a standard industry design, consisting of two 50 percent-capacity packaged units designed to process the sanitary water/waste to meet local and state regulations for effluent quality in accordance with the VPDES permit. Treated water at a maximum rate of approximately 105 gpm would be routed to the WHTF just south of the Units 1 and 2 circulating water discharge structure. The sludge generated by the treatment facility would be transported to a licensed sanitary waste landfill for disposal.

The sludge would be regularly monitored for radioactivity. In the event that sewage sludge becomes radioactively contaminated, the contents of the sludge tank would be pumped to a drying bed. The sludge would be allowed to dry completely. Once dry, Radiation Protection personnel would survey the bed and collect all contaminated sludge. The sludge would be packaged in an appropriately sized DOT approved shipping container for disposal at a licensed burial facility. Alternatively, the packaged sludge may be shipped to a third party vendor for further processing (e.g., volume reduction by incineration), re-packaging and final disposal.

Approved technology for processing wastes would include laboratory testing of effluents to ensure proper treatment. Monitoring would be implemented to ensure compliance with regulatory limits.

Section 3.6 References

1. U.S. Environmental Protection Agency, "EPA Steam Electric Power Generating Point Source Category, 126 Priority Pollutants," 40 CFR 423, Appendix A.
2. Commonwealth of Virginia, Department of Environmental Quality, "VPDES Permit No. VA0052451, Authorization to Discharge Under the Virginia Pollutant Discharge Elimination System and the Virginia State Water Control Act," October 25, 2007.
3. Commonwealth of Virginia, State Water Control Board, "Sewage Collection & Treatment Regulations," 9 VAC 25-790, January 1, 2008.

3.7 Power Transmission System

ESP-ER Section 3.7 described the anticipated switchyard interfaces and transmission system for new units at NAPS and, based on initial evaluation, stated that existing transmission lines were expected to have sufficient capacity to carry the output of the existing and new units. ESP-ER Section 3.7 stated that detailed system load studies could not be performed until an in-service date for the new units is established.

A system load flow study has now been performed for Unit 3, which determined that a new transmission line and other system reinforcements would be required for grid reliability in association with the interconnection of Unit 3. The sections below provide a description of the final configuration of switchyard interfaces and transmission system connections that would be made for Unit 3.

3.7.1 Switchyard Interfaces

Unit 3 would be connected to the existing 500 kV switchyard by an overhead conductor circuit. The existing switchyard would be extended to the north for construction of additional 230 kV bays. The interface of the extension with the transmission system is through the existing switchyard.

"PJM Generator Interconnection Q65 North Anna 500 kV (1570 MW Capacity/1594 Energy Report) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies, revised September 2013" (Reference 1), describes the system reinforcements associated with the interconnection of new Unit 3:

- Replacement of existing 500 kV circuit breakers and associated high voltage equipment with ones with higher current and/or short circuit rating.
- Adding a new 500 kV bay to support the new North Anna-to-Ladysmith transmission line.
- Adding a 230 kV bay parallel to the existing 230 kV bay on the North side to support the reserve auxiliary transformer's feed to Unit 3.

New control and relay protection equipment would be installed in a new or expanded control house. Some existing service systems, such as grounding, raceway, lighting, AC/DC station service, and switchyard lightning protection would be expanded or modified.

3.7.2 Transmission System

The PJM System Impact Study determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new transmission line would be installed in the NAPS-to-Ladysmith corridor, on new transmission towers located in proximity to the existing towers. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long.

Transmission tower separation, line installation, and clearances to ground will be consistent with the National Electrical Safety Code (NESC) and transmission line standards. Basic tower structural design parameters, including the number of conductors and other considerations such as height, materials, color, and finish will be consistent with transmission line design standards. Marking for aircraft visibility will be consistent with the existing adjacent tower. The new towers are expected to be about 10 percent taller, but not more than 20 feet taller, than the existing towers. No expansion of the corridor is required. Electrical design parameters, including the electric-field-induced current from transmission lines will not exceed allowable NESC code requirements (Reference 2). In addition, considerations for visibility for aircraft are the same as for the existing, adjacent towers.

Conductors and other line parameters will meet the PJM and transmission line design criteria. The tower grounding system will be verified for safety and adequacy.

The noise levels resulting from new transmission line operations will be consistent with the existing transmission system. Actual decibel noise levels will be minimized by proper sizing of conductors and the use of corona-free hardware. Examples of the measurement of audible noise from overhead transmission lines are given in IEEE Standard 656-1992 (Reference 3).

Section 3.7 References

1. PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500 kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

2. National Electrical Safety Code (NESC 2007 - Section 21, Rule 232.C.1.c).

3. IEEE Standard 656-1992, "IEEE Standard for the Measurement of Audible Noise from Overhead Transmission Lines."

3.8 Transportation of Radioactive Materials

The information for this section is provided in ESP-ER Section 3.8 and associated impacts are resolved as SMALL in FEIS Section 6.2.

3.8.1 Transportation of Unirradiated Fuel

No new and significant information has been identified for this section.

3.8.2 **Transportation of Spent Fuel**

The following commitment was identified in FEIS Section 6.2.2.2 and is addressed below:

> Consequently, the impacts of crud and activation products on spent fuel transportation accident risks will need to be examined at the CP or COL stage.

The highest surface radioactivity of Co-60 in spent fuel crud available for spallation during transportation accidents for the proposed Unit 3 ESBWR is expected to be 579 $\mu Ci/cm^2$. NUREG/CR-6672 (Reference) indicates that the total surface area for a BWR fuel rod is approximately 1600 cm^2. The number of fuel rods for an ESBWR assembly is expected to be about 100. As a result, the total surface area of an ESBWR spent fuel assembly would be 160,000 cm^2. The weight of UO_2 for each ESBWR assembly is estimated to be 0.163 MTU (163 kg U). Thus, the unit-specific inventory of Co-60 in ESBWR spent fuel crud available for spallation during transportation accidents is estimated to be 568 Ci/MTU.

The unit-specific inventory of Co-60 in spent fuel crud used for the FEIS analysis was 2730 Ci/MTU (associated with the ABWR), which also represented the entire inventory of activation products in spent fuel. As such, the available unit-specific inventory of Co-60 in ESBWR spent fuel crud is about a factor of 5 lower than that used in the evaluation for the FEIS.

The FEIS states that activation products will need to be examined at the CP or COL stage. Because FEIS Table 6-8 contains data on activation products for the ESBWR, no additional information is required.

Based on the above discussion, the conclusion presented in the FEIS that the impact is SMALL remains valid.

3.8.3 Transportation of Radioactive Waste

No new and significant information has been identified for this section.

Section 3.8 Reference

U.S. Nuclear Regulatory Commission, "Reexamination of Spent Fuel Shipment Risk Estimates," NUREG/CR-6672, March 2000.

Chapter 4 Environmental Impacts of Construction

4.1 Land-Use Impacts

The information for this section is provided in ESP-ER Section 4.1 and associated impacts are resolved as SMALL in FEIS Sections 4.1 and 4.6. Supplemental information is provided in Sections 4.1.1 through 4.1.4, below.

4.1.1 The Site and Vicinity

In ESP-ER Section 4.1.1.4, it was concluded that all construction activities for new units, including ground-disturbing activities, would occur within the NAPS site boundary. It has now been determined that offsite modifications would be required for Unit 3 to support the transport of the reactor pressure vessel and other large components to the site.

It is expected that the reactor pressure vessel and other large components (e.g., the main generator, large plant modules) would be transported by barge up the Mattaponi River to an offload location near the town of West Point or the town of Walkerton. From West Point or Walkerton, the oversized equipment would be transported to the site either entirely over-the-road or by a combination of over-the-road and rail.

Road improvements (e.g., repairs, widening, and filling-in low areas) would be required for over-the-road transport. Lowering sections of road for clearance under bridges and installation of temporary road bridges may also be needed. Removal of overhead and/or lateral interferences (wires, signs, etc.) would also be required for both transport methods.

Transport operations for the large components, including the road/rail modifications described above, would be coordinated with State and local officials to minimize land use and other impacts. Upon completion of the transports, temporary structures would be removed, interferences would be re-installed, and disturbed areas would be restored back to their original condition or better. Permanent changes are anticipated to be limited in scope and would be coordinated with State and local officials.

For these reasons, land use and other impacts associated with transport of large components to the North Anna site will be SMALL.

4.1.2 Transmission Line Rights-of-Way and Offsite Areas

As described in Section 3.7, the PJM System Impact Study (Reference) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new line would be installed on new transmission towers in the existing NAPS-to-Ladysmith corridor. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long.

Land-use impacts from constructing the new transmission line would be limited to the existing corridor and access roads and would be minimal. The potential impacts within the corridor and access roads could include:

- Removal of natural landscape (small trees, bushes, vegetation)
- Soil disturbance and erosion
- Siltation of streams
- Tree and brush piles
- Damage to culverts, driveways, and roadways
- Disturbance of archaeological artifacts

Clearing methods for trees, bushes and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed. Appropriate actions (e.g., stop work) would be taken following discovery of potential historic or archaeological resources.

Once the construction of the transmission line has been completed, the transmission corridor and access roads would be restored by means such as:

- Rehabilitation of land including discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch)
- Removal and proper disposal of debris left or caused by construction
- Restoration of damaged property to its original condition and to the satisfaction of the property owner

Thus, the construction of a new transmission line would result in no additional land use, and land use impacts will be SMALL.

4.1.3 **Historic Properties and Cultural Resources**

A proposed large component transport route was evaluated for potential disruptions to historic properties and cultural resources. The study revealed historic properties and cultural resources may be disrupted in three locations. These locations are described in detail in Section 2.5.3.5, Large Component Transport Route. They include the historic train depot in Beaverdam, a ferry landing, and the North Anna Battlefield.

Temporary modifications to the proposed large component transport route are expected to be minor with little potential to affect cultural resources. Temporary modifications may be required at the historic train depot in Beaverdam, which has been recommended for inclusion in the National Register of Historic Places. Other temporary modifications may be needed at three other locations:

the preferred roll-off location (the ferry landing); the North Anna River crossing at Route 30; and the I-95 crossing. The ferry landing is eligible for inclusion in the National Register. All three proposed modifications have potential to affect cultural resources. The North Anna River crossing is likely to impact a previously recorded archaeological site.

The I-95 crossing and the North Anna River crossing are within the North Anna Battlefield. The North Anna Battlefield is eligible for inclusion in the National Register of Historic Places.

Mitigating measures for these disruptions include avoidance of sensitive areas whenever possible, rehabilitation of land, removal of debris, and restoration of damaged property to its original condition or as close as possible. Impacts resulting from the transport of large components are expected to be SMALL.

The new 500 kV line proposed for the existing NAPS-to-Ladysmith corridor has the potential to impact two newly-identified sites that are eligible for inclusion in the National Register of Historical Places—one archaeological resource and one architectural resource. These sites are described in Section 2.5.3.3. The archaeological resource is located within the right-of-way under the existing lines, but the potential for impact is minimized by the location of the site with respect to the new lines. The site is approximately 70 feet north of the area to be impacted by the new lines and lies across the gravel access road from the area to be impacted by the construction of the new transmission towers. To further avoid any impacts on this archaeological resource, it will be marked and/or flagged prior to and during construction.

The closest architectural resource is about one-quarter mile north of the proposed transmission line. As such, the only expected impact would be visual. This impact is minimized by the presence of the existing transmission lines within the corridor. The new towers are expected to be about 10 percent taller, but not more than 20 feet taller, than the existing towers. If the final tower design has the potential to visually impact the architectural resources, a photo simulation analysis will be performed to assess the impacts. The visual impact upon the historic property will be further minimized by selection of material colors that help the towers blend in to the natural surroundings (See Section 5.6.3.4).

An assessment of historic and cultural resources in the additional property acquired for construction support is provided in Appendix 4A.

4.1.4 **Additional Property**

Dominion owns additional property contiguous with the NAPS site. The additional property will provide alternative space for Unit 3 construction-related activities and facilities such as laydown areas, spoils storage, and access roads, but will not be part of the NAPS site. Further information is provided in Appendix 4A.

Section 4.1 Reference

PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

4.2 Water-Related Impacts

The information for this section is provided in ESP-ER Section 4.2 and associated impacts are resolved as SMALL in FEIS Section 4.3. Supplemental information is provided in Sections 4.2.1.1 and 4.2.1.2, below.

4.2.1 Hydrologic Alterations

4.2.1.1 Surface Water

The ESP-ER describes two small ephemeral streams that discharge in the vicinity of the cooling tower area and indicates that these streams would be impacted by construction activities. These streams are designated Stream A and Stream B on ESP-ER Figure 4.2-1. A third ephemeral stream (designated as Stream C) has been identified in the cooling tower area. All three streams are shown on ESP-ER Figure 2.4-5, ESP-ER Figure 2.4-6, and Figure 1.1-1. It has now been determined that Unit 3 construction activities would alter only Streams B and C and that Stream A would not be altered, as it is outside of the construction area. The drainage area of Stream A and Stream C are not substantially different, and the discharge point of both streams is Lake Anna. Once construction is complete, the area would continue to drain to the wetlands, through stream beds, to Lake Anna. Thus, while the particular streams identified as being altered by construction have changed, the impact remains SMALL because the area of concern is not substantially different than what was evaluated in the ESP-ER.

The ESP-ER indicated that no new transmission lines or alterations to existing rights-of-way were expected; however, the PJM System Impact Study (Reference) concludes that an additional transmission line would be required as a system reinforcement associated with the interconnection of Unit 3. The new transmission line would be installed in the NAPS-to-Ladysmith corridor on new transmission towers located in proximity to the existing towers. Construction activities for the new transmission line would be performed in accordance with existing corridor procedures.

Section 2.4 identifies wetlands crossed by the Ladysmith corridor. To the extent practical, the construction of new transmission towers would avoid alterations to wetlands and shorelines. In accordance with existing corridor procedures, impacts from construction of overhead transmission lines adjacent to streams would be minimized through various practices, including:

- Hand-clearing of trees and brush located within approximately 100 feet of a stream or ditch with running water

- Removing material approximately three inches in diameter and above from the buffer and leaving material less than three inches undisturbed
- Limiting the disturbance of soil within an approximate 100-foot buffer zone around streams and ditches
- Crossing creeks and streams at right angles in one location on the corridor using culverts, temporary bridges, or large aggregate stone
- Performing work related to stream crossings in accordance with state standards and specifications
- Removing materials from temporary stream crossings at the completion of the project
- Removing logs, trimmings, or brush from ditches, creeks, and drains

In addition impacts from construction of structure foundations and structure erections would be mitigated through various practices, including:

- Evaluation of the site with respect to earth disturbance and erosion potential
- Stabilization of the work site prior to moving to the next location
- Restoration of areas damaged during foundation construction and structural erection activities to approximate original grade and installation of erosion and sedimentation control measures
- Maintaining temporary erosion and sedimentation controls until permanent stabilization is achieved.

Should wetlands be impacted, the U.S. Army Corps of Engineers and other appropriate agencies would be consulted and permits and approvals obtained as necessary.

For these reasons, no significant hydrologic alterations are anticipated from the installation of the new transmission line and water-related impacts will remain SMALL.

Additional property contiguous with the NAPS site will be utilized for Unit 3 project construction support. An assessment of the construction impacts is provided in Appendix 4A.

4.2.1.2 Groundwater

Five domestic water wells are planned for installation inside the EAB. Two are anticipated for batch plant operations with an expected water withdrawal rate of approximately 90 gpm. Three additional domestic water wells with an expected water withdrawal rate of approximately 50 gpm are planned for installation and are anticipated to be part of the permanent potable water system. Two of those three wells are expected to be used during construction activities. The expected average aggregate water withdrawal rate on all construction wells is approximately 130 gpm. Information on groundwater use associated with the additional property acquired for construction support is provided in Appendix 4A.

4.2.2 **Water-Use Impacts**

No new and significant information has been identified for this section.

4.2.3 **Future Growth and Development Impacts**

No new and significant information has been identified for this section.

Section 4.2 Reference

PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

4.3 Ecological Impacts

The information for this section is provided in ESP-ER Section 4.3 and associated impacts are resolved as SMALL in FEIS Section 4.4. Supplemental information is provided in Sections 4.3.1.1, 4.3.1.3, 4.3.1.4, and 4.3.2.

As discussed in Section 3.7, a new 500 kV transmission line required for Unit 3 would be installed along the existing NAPS-to-Ladysmith corridor. The following sections provide supplemental information regarding the impacts of this construction on terrestrial and aquatic ecological resources.

4.3.1 **Terrestrial Ecosystems**

4.3.1.1 **Transmission Corridors**

The new transmission line would be installed on new transmission towers in the existing NAPS-to-Ladysmith corridor. Because the transmission corridor has been maintained at a full 275-foot width, widening to accommodate the additional line would not be required. The NAPS-to-Ladysmith corridor passes through land that is typical of north-central Virginia, such as pastures, row crops, forests and shrub bogs. No areas designated as critical habitat for endangered species by the U.S. Fish and Wildlife Service or VDEQ exist along or adjacent to the transmission line corridor. The corridor does not cross any state or federal parks, wildlife refuges, or wildlife management areas. As described in Section 2.4, potential habitat for the Epling's hedgenettle was identified during a plant-specific habitat survey conducted in November 2009 (Reference 5) for the Blantons Powerline Conservation Site (Conservation Site) (through which the NAPS-to-Ladysmith transmission corridor runs). The Epling's hedgenettle, while neither a federally- nor state-listed species, is considered rare by the Commonwealth of Virginia and the VDCR recommends the avoidance of this species (Reference 6). Follow-up plant-specific identification surveys, conducted during the flowering seasons in 2010 and 2012 (Reference 9) (Reference 10), determined that the

Epling's hedgenettle was present. Survey results were communicated to appropriate regulatory agencies (Reference 11).

Existing access roads would be used to bring the tower components and heavy equipment to the new tower locations, and some clearing of the access roads is anticipated. Land clearing necessary to accommodate the tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices, as well as applicable regulatory requirements. Clearing methods for trees, bushes and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Areas disturbed during tower construction would be restored to the original grade, and temporary erosion and sedimentation controls would remain in place until permanent stabilization by means such as re-vegetation is achieved.

Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed. Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.

Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project.

A wetland delineation was conducted along the NAPS-to-Ladysmith corridor in August 2008. (Reference 1) Based upon a field analysis of the vegetation, soils, and hydrology conducted in accordance with the "Corps of Engineers Wetlands Delineation Manual" (1987 Manual) (Reference 2), 39 potential non-tidal wetland areas were flagged.

The current design plan for construction of the transmission line is to place the proposed towers adjacent to existing towers. Out of the 72 potential tower locations identified, one wetland area was located within a proposed tower footprint and one wetland area was located immediately adjacent to a proposed tower. No other wetland areas were identified within the footprints of the remaining towers. The proposed towers will be located in such a manner as to avoid wetland impacts, to the greatest extent practicable, and in accordance with existing regulations, procedures, and/or best management practices.

Wetland boundaries, as defined by regulations, were verified through a site review by the U.S. Army Corps of Engineers (USACE) as indicated in their September 2008 letter (Reference 3), and which contains an approved jurisdictional determination.

Any necessary permits will be obtained prior to work in these areas which is considered structure or fill under current regulations.

Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property to its original condition and to the satisfaction of the property owner.

Dust suppression techniques and routine equipment maintenance would be employed to reduce airborne emissions.

The construction activity and associated noise would temporarily disperse nearby wildlife, and a small amount of habitat associated with the tower foundations would be impacted. Although small amphibians and mammals may be displaced, no critical habitats or known protected species would be impacted. Once construction is completed and the corridor is re-vegetated, displaced animals would return to the area.

Thus, impacts from the installation of the transmission line and new transmission towers on terrestrial ecology will be SMALL.

4.3.1.2 **ESP Site**

As described in Section 2.4, potential habitat for the small whorled pogonia was identified during a plant-specific habitat survey conducted in November 2009 (Reference 7) for the ESP Site. Follow-up plant-specific identification surveys, conducted during the flowering season, have determined that the small whorled pogonia was not present in the area of potential effects. (Reference 8)

4.3.1.3 **Additional Property**

Additional property contiguous with the North Anna site will be utilized for Unit 3 project construction support. Additional information is provided in Appendix 4A.

4.3.1.4 **Transportation of Large Components**

Based upon a field analysis in accordance with the "Corps of Engineers Wetlands Delineation Manual" (Reference 2), there were 31 wetlands and 26 waterways scattered along a proposed large component transport route. Dependent upon size of modules and equipment, temporary construction may result at the crossing of I-95. Depending on the final route selected, improvements to the road will impact no more than two potential tidal wetlands, five non-tidal wetland areas, and create a temporary impact on a few waterways. Mitigation measures for these wetlands and waterways would include maintaining temporary erosion and sedimentation controls until permanent stabilization is achieved, removal of all debris, and rehabilitation of disturbed lands as close to their original condition as possible. Wetland impacts from the temporary improvements to the transport route will be SMALL.

4.3.2 **Aquatic Ecosystems**

No new transmission towers would be constructed in Lake Anna (or other water bodies) and, as discussed in Section 4.3.1.1, a buffer zone would be maintained around water bodies, where feasible. Construction within wetlands would be avoided to the extent practical. Should wetlands be impacted, the U.S. Army Corps of Engineers and other appropriate agencies would be consulted and permits and approvals obtained as necessary.

Thus, impacts from construction of the new transmission line and associated transmission towers on aquatic ecosystems will be SMALL.

4.3.2.1 **Additional Property**

Additional property contiguous with the existing North Anna site will be utilized for Unit 3 project construction support. An assessment of the construction impacts is provided in Appendix 4A.

Section 4.3 References

1. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation Report for the Proposed Unit 3 500-kV Transmission Line," Sparks, Maryland, September 2008.

2. Environmental Laboratory, "Corps of Engineers Wetlands Delineation Manual," Technical Report Y-87-1, U.S. Army Engineer Waterways Experiment Station, Vicksburg, Mississippi, January 1987.

3. Department of the Army, Northern Virginia Regulatory Section, NAO 2008-02731 (Lake Anna), September 24, 2008.

4. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation Report for the Proposed Unit 3 Heavy Haul Route," June 2009.

5. Williamsburg Environmental Group Inc., "Habitat Survey for the Epling's Hedge-nettle (*Stachys eplingii*) and Small Whorled Pogonia (*Isotria medeoloides*) Blantons Powerline Conservation Site, Caroline County, Virginia," November 2009.

6. Virginia Department of Conservation and Recreation, letter from Rene Hypes to Michael Sackschewky, Pacific Northwest National Laboratory, dated September 29, 2009.

7. Williamsburg Environmental Group Inc., "Habitat Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," November 2009.

8. Williamsburg Environmental Group Inc., "Detailed Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," August 2012.

9. Williamsburg Environmental Group Inc., "Detailed Survey for the Epling's Hedge-nettle (Stachys eplingii) Blantons Powerline Conservation Site, Caroline County, Virginia," July 2010.

10. Williamsburg Environmental Group Inc., "Detailed Survey for the Epling's Hedge-nettle (Stachys eplingii) Blantons Powerline Conservation Site, Caroline County, Virginia," July 2012.

11. Dominion Resources Services, Inc., "Transmittal of Epling's Hedgenettle Survey Report Virginia Electric and Power Company (Dominion) North Anna Power Station - Proposed Unit 3 Louisa County, Virginia," March 7, 2011.

4.4 Socioeconomic Impacts

The information for this section is provided in ESP-ER Section 4.4 and associated impacts are resolved in FEIS Sections 4.2, 4.5, 4.7, and 4.8. These FEIS sections resolved that adverse impacts range from SMALL to MODERATE and beneficial impacts range from SMALL to MODERATE. Supplemental information is provided below.

As discussed in Section 3.7, the new 500 kV transmission line required in connection with Unit 3 would be installed in the existing NAPS-to-Ladysmith corridor. As discussed in Section 2.4, a portion of this new transmission line would cross Lake Anna, as well as other waterways and wetlands. As a precaution, during installation of the new transmission line across Lake Anna and the other waterways, access to the subject areas would be temporarily restricted from recreational use. Although this would limit the areas that are accessible to the public for recreational use, the limitation would be temporary in nature, and full use would be restored once the installation has been completed. A communications plan would be developed to notify local citizens concerning the impacts of this activity. Notification would include a description of the construction schedule with expected durations of activities. Typically, interruptions affecting recreation in waterways are expected to be of short duration. Implementation of the communications plan would include advanced coordination with appropriate agencies and organizations, public notices, use of actual "day-of" postings, and notification to marine vessels via citizen band radio. The impacts of construction of the transmission line on the recreational use of Lake Anna and the other waterways will be SMALL, and further mitigation is not warranted.

4.5 Radiation Exposure to Construction Workers

The information for this section is provided in ESP-ER Section 4.5 and associated impacts are resolved as SMALL in FEIS Section 4.9.

Supplemental information is provided below.

4.5.1 Site Layout

No new and significant information has been identified for this section.

4.5.2 Radiation Sources

No new and significant information has been identified for this section.

4.5.2.1 Direct Radiation

No new and significant information has been identified for this section.

4.5.2.2 Gaseous Effluents

Sources of gaseous releases at Units 1 and 2 include the waste decay tanks, boron recovery and high-level waste tanks, containment purge system, auxiliary building vent, main condenser air ejector vents, auxiliary steam drain receiver, Turbine Building ventilation exhaust, and gland seal ejector vent. The annual radioactive effluent release reports for the years 2001 to 2011 indicate average annual gaseous releases of 48 Ci of fission and activation gases and 55 Ci of tritium (References 1 through 11).

4.5.2.3 Liquid Effluents

Effluents from the liquid waste disposal system of Units 1 and 2 produce small amounts of radioactivity in the North Anna Reservoir and the WHTF. The annual effluent reports for the years 2001 to 2011 indicate average annual liquid releases of 0.2 Ci of fission and activation products and 966 Ci of tritium (References 1 through 11).

4.5.3 Measured and Calculated Dose Rates

No new and significant information has been identified for this section.

4.5.3.1 Direct Radiation

Thermo-luminescent dosimeter (TLD) measurements at the west protected area fence of Units 1 and 2 from 2001 to 2011 indicate an average annual dose of 72 mrem, which equates to a continuous dose rate of 8.22E-3 mrem/hr. This location is along the eastern edge of the Unit 3 construction area.

TLD readings taken along the ISFSI perimeter fence for the two-year period third quarter 2010 to third quarter 2012 indicate a maximum quarterly dose of 192 mrem during the fourth quarter of

2011, when there were 27 casks on Pad One and 13 on Pad Two for a total of 40 casks. The plan for the ISFSI is to load 28 casks on Pad One and 40 on Pad Two for a total of 68 casks. The maximum TLD reading of 192 mrem may be multiplied by 68/40 to estimate the dose from a fully loaded ISFSI. For conservatism, however, a growth factor of two is applied. Based on 91 days per quarter and 24 hours per day, 192 mrem/quarter is equivalent to a dose rate of 8.79E-2 mrem/hr. Multiplying by the growth factor of two yields a dose rate of 0.176 mrem/hr at the ISFSI fence from a fully loaded ISFSI.

The dose rate at the construction area boundary near the ISFSI may be estimated by dividing the ISFSI fence dose rate by a distance reduction factor. The distance from the ISFSI to the ISFSI fence is 203 ft (Reference 12). The distance from the ISFSI to the nearest point of the construction area is approximately 500 ft (Figure 1.1-1). A Monte Carlo calculation was performed to assess the dose rate as a function of distance from the ISFSI when loaded with 84 casks, which bounds the planned 68 casks. This calculation shows dose rates of 1.39 mrem/hr at 203 ft and 0.24 mrem/hr at 500 ft, yielding a reduction factor of 5.8. Dividing the ISFSI fence dose rate of 0.176 mrem/hr by 5.8 yields a dose rate of 3.04E-2 mrem/hr at the construction area boundary nearest the ISFSI.

The same method is used to estimate the ISFSI dose rate in the center of the construction area. The distance from the ISFSI to the center of the construction area is approximately 1600 ft (Figure 1.1-1). The distance reduction factor for this distance is 294. Dividing the ISFSI fence dose rate of 0.176 mrem/hr by 294 yields a dose rate of 5.98E-4 mrem/hr at the center of the construction area.

4.5.3.2 **Gaseous Effluents**

The annual radioactive effluent release reports for 2001 to 2011 indicate average dose rates of 1.01E-2 mrem/yr for the whole body and 0.129 mrem/yr for the critical organ of the maximally exposed member of the public due to the release of gaseous effluents from Units 1 and 2, calculated in accordance with the Offsite Dose Calculation Manual (ODCM) for Units 1 and 2.

According to the ODCM, gaseous effluent doses to the members of the public are calculated at or beyond the site boundary (Reference 13). The construction area is closer to the effluent release point than is the site boundary. A review of the atmospheric dispersion factors (χ/Q values) for Units 1 and 2 indicates that the ratio of χ/Q a few hundred feet from these units to that at the site boundary is no more than a factor of ten (Reference 14). Hence, the dose rates for the maximally exposed member of the public are multiplied by ten, yielding 0.101 mrem/yr for the whole body and 1.29 mrem/yr for the critical organ of the construction worker.

4.5.3.3 **Liquid Effluents**

The annual radioactive effluent release reports for 2001 to 2011 (References 1 through 11) indicate average dose rates of 0.357 mrem/yr for the whole body and 0.435 mrem/yr for the critical organ of the maximally exposed member of the public due to the release of liquid effluents from Units 1 and 2, calculated in accordance with the ODCM for Units 1 and 2.

4.5.4 Construction Worker Doses

Construction worker doses are conservatively estimated using the following information:

- The estimated maximum dose rate for each exposure pathway
- An exposure time of 2500 hours per year per worker
- A peak loading of 4088 construction workers per year

Using the above worker occupancy time and workforce size, annual doses to the maximally exposed worker as well as the peak workforce are calculated due to direct radiation and gaseous and liquid effluents.

4.5.4.1 Direct Radiation Doses

The TLD at the west protected area fence of Units 1 and 2 is along the eastern edge of the construction area while the maximum dose from the ISFSI occurs along the southern edge of the construction area. Although these two locations are separated by more than 1000 ft (Figure 1.1-1), the direct radiation dose rates at the two locations are conservatively added, yielding a total dose rate of 3.86E-2 mrem/hr. Multiplying by the worker exposure time of 2500 hr yields a maximum annual dose of 96.4 mrem due to direct radiation.

While the maximum dose occurs at the southern edge of the construction area, the center of the construction area is representative of the location of the average member of the construction workforce over the course of a year. Adding the west protected area fence dose rate to the ISFSI dose rate at the center of the construction area yields a total dose rate of 8.82E-3 mrem/hr. Multiplying by the worker exposure time of 2500 hr yields an annual worker dose of 22.0 mrem at this location.

4.5.4.2 Gaseous Effluents

The gaseous effluent dose rates in Section 4.5.3.2 are multiplied by the ratio of expected hours worked per year per worker by the number of hours in a year (2500/8760) to account for the fraction of the year that workers are exposed, resulting in doses of 2.89E-2 mrem to the whole body and 0.368 mrem to the critical organ. These doses are converted into total effective dose equivalent (TEDE) by applying a weighting factor of 0.3 to the critical organ dose (Reference 15) and adding the product to the whole body dose, yielding an annual dose of 0.139 mrem TEDE.

4.5.4.3 Liquid Effluents

Although construction workers are not expected to be exposed to liquid effluents from Units 1 and 2, it is assumed that they receive the same dose rates as the maximally exposed member of the public. The liquid effluent dose rates in Section 4.5.3.3 are multiplied by 2500/8760 to account for the fraction of the year that workers are exposed, resulting in doses of 0.102 mrem to the whole body and 0.124 mrem to the critical organ. Applying a weighting factor of 0.3 to the organ dose and adding the product to the whole body dose, an annual dose of 0.139 mrem TEDE is estimated.

4.5.4.4 Total Doses

Adding the doses from the preceding subsections of 96.4 mrem TEDE due to direct radiation, 0.14 mrem TEDE due to gaseous effluents, and 0.14 mrem TEDE due to liquid effluents, the total annual dose to the maximally exposed construction worker is estimated as 97 mrem TEDE. As indicated in Section 4.5.4.1, the maximum dose rate in the construction area is less than 0.04 mrem/hr. These doses are within the regulatory limits of 10 CFR 20.1301. Since the calculated doses meet the public dose criteria of 10 CFR 20 1301, the workers would not need to be classified as radiation workers.

Adding the doses from the preceding subsections of 22.0 mrem TEDE due to direct radiation, 0.14 mrem TEDE due to gaseous effluents, and 0.14 mrem TEDE due to liquid effluents, the total annual dose to the average member of the construction workforce is estimated as 22 mrem TEDE. Multiplying by 4088 workers yields a collective dose of 91 person-rem.

The calculated doses are based on available dose rate measurements for the site. It is possible that these dose rates would increase in the future as site conditions change. However, the construction area would be continually monitored during the construction period and appropriate actions would be taken as necessary to ensure that doses to the construction workers are as low as reasonably achievable (ALARA).

Section 4.5 References

1. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2001 to December 31, 2001).
2. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2002 to December 31, 2002).
3. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2003 to December 31, 2003).
4. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2004 to December 31, 2004).
5. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2005 to December 31, 2005).

6. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2006 to December 31, 2006).

7. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2007 to December 31, 2007).

8. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2008 to December 31, 2008).

9. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2009 to December 31, 2009).

10. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2010 to December 31, 2010).

11. Annual Radioactive Effluent Release Report, North Anna Power Station (January 01, 2011 to December 31, 2011).

12. North Anna Independent Spent Fuel Storage Installation Safety Analysis Report, Revision 6.

13. Offsite Dose Calculation Manual (North Anna), Procedure Number VPAP-2103N, Revision 16.

14. North Anna Power Station Updated Final Safety Analysis Report, Revision 45.

15. Limits for Intake of Radionuclides by Workers, ICRP Publication 30, Part 1, International Commission on Radiological Protection, Pergamon Press, 1979.

4.6 Measures and Controls to Limit Adverse Impacts During Construction

Measures and controls to limit adverse impacts during construction were addressed in ESP-ER Section 4.6 and in FEIS Section 4.10. Those measures and controls remain applicable to Unit 3, along with the following new mitigation measures and controls:

- Upon completion of the transports, temporary structures would be removed, interferences would be reinstalled, and disturbed areas would be restored. (Section 4.1.1).
- The new transmission line would be located in an existing corridor and constructed under practices and procedures applicable to the existing transmission lines. (Sections 4.1.2, 4.2.1.1 and 4.3.1.1).
- Land clearing necessary to accommodate the new transmission tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices (Section 4.3.1.1), as well as all applicable regulations.

- Clearing methods for small trees, bushes, and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately 3 inches in diameter and above would be removed from the buffer, leaving material less than 3 inches undisturbed (Sections 4.1.2, 4.2.1.1, and 4.3.1.1).
- Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch), 2) properly removing and disposing debris left or caused by construction, and 3) restoring damaged property (Sections 4.1.2 and 4.3.1.1).
- Appropriate actions (e.g., stop work) would be taken following discovery of potential historic or archaeological resources (Sections 4.1.2 and 4.1.3).
- While the goal is zero impacts to historic properties and cultural resources located adjacent to the proposed large component transport route, appropriate actions for potential impacts include rehabilitation of land, removal of debris, and restoration of damaged property (Section 4.1.3).
- Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project (Sections 4.2.1.1 and 4.3.1.1).
- Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area (Sections 4.2.1.1, 4.3.1.1, and 4.3.1.4).
- To the extent practicable, construction would avoid alterations to shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) would be consulted, and permits and approvals would be obtained as necessary. (Sections 4.2.1.1 and 4.3.2).
- Dust suppression techniques would be utilized and equipment maintenance employed to reduce airborne emissions (Section 4.3.1.1).
- Potential impacts to wetlands along the proposed large component transport route would be addressed by maintaining temporary erosion and sedimentation controls until permanent stabilization is achieved, removing debris, and rehabilitating disturbed lands as practicable (Section 4.3.1.4).

- As a safety precaution, during installation of the transmission lines, access to the area would be temporarily restricted from recreational use (Section 4.4).
- To help avoid impacts to the archaeological resource along the transmission corridor, the identified archaeological site will be marked and/or flagged prior to and during construction of the new transmission line (Section 4.1.3).
- Impacts to wetlands within the additional property would be addressed through preservation of other onsite streams or through purchasing offset credits from an approved mitigation bank (Appendix 4A).
- The additional property area will be stabilized and facilities will be removed upon completion of the construction of Unit 3 (Appendix 4A).

4.7 [Deleted]

Appendix 4A Environmental Information Concerning Additional Property

4A.1 Status of Activities Related to Additional Property

Dominion owns additional property contiguous with the existing NAPS site. The additional property will provide supplemental space for Unit 3 construction activities such as laydown areas, spoils storage, and access roads, but will not be part of the NAPS site. It has been determined through GIS data that the area of the additional property is approximately 111 acres, as shown in Figure 1.1-1.

4A.2 Habitat Assessment

A habitat assessment for selected rare, threatened and endangered species was conducted for the additional property in May 2008. (Reference 3) Four bird species of concern listed by the Virginia Natural Heritage Program as threatened or in decline were identified for this area, and the evaluation considered habitat availability for these birds on the additional property. The report concludes that suitable habitat for each of these four species was not present. USACE letter dated August 27, 2008 confirms that no known populations of federally-listed threatened or endangered species are located on the additional property. (Reference 2) However, the Commonwealth of Virginia Department of Conservation and Recreation requested that Dominion conduct a plant-specific habitat survey to determine if the additional property contains habitat suitable for the small whorled pogonia. (Reference 6) The plant-specific habitat survey identified three small areas in the additional property, comprising a total area of 4.5 acres that are potentially suitable habitat for the small whorled pogonia. (Reference 7) Follow-up plant-specific identification surveys, conducted during the flowering season, determined that the small whorled pogonia was not present within these habitat areas. (Reference 8)

A habitat map of the additional property is provided as Figure 4A-2. The background habitat mosaic of Figure 4A-2 was created from the 2001 National Land Cover Dataset (NLCD). NLCD 2001 land cover data is the most current database available. The NLCD codes were used for mapping habitat types and to develop Figure 4A-2.

NLCD Code	NLCD Code Description	Acres	Percent of Total Acreage
21	Developed Open Space	0.3	0.3
22	Developed Low Intensity	0.1	0.1
31	Barren Land (rock/sand/clay)	6.3	6.6
41	Deciduous Forest	51.0	53.4
42	Evergreen Forest	36.9	38.6
81	Pasture/Hay	0.9	1.0
82	Cultivated Crops	0.0	0.0
	Total	95.5	100.0

NLCD = National Land Cover Data developed by a consortium of federal agencies: U.S. Geological Survey, U.S. Environmental Protection Agency, National Oceanic and Atmospheric Administration, U.S. Forest Service, NASA, Bureau of Land Management, LANDFIRE, Natural Resources Conservation Service, National Park Service, U.S. Fish and Wildlife Service, Office of Surface Mining.

2001 NLCD Code Definitions (2001 Data are the most recent data available)

21. Developed, Open Space - Includes areas with a mixture of constructed materials, but mostly vegetation in the form of lawn grasses. Impervious surfaces account for less than 20 percent of total cover. These areas most commonly include large-lot single-family housing units, parks, golf courses, and vegetation planted in developed settings for recreation, erosion control, or aesthetic purposes.

22. Developed, Low Intensity - Includes areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 20-49 percent of total cover. These areas most commonly include single-family housing units.

31. Barren Land (Rock/Sand/Clay) - Barren areas of bedrock, desert pavement, scarps, talus, slides, volcanic material, glacial debris, sand dunes, strip mines, gravel pits and other accumulations of earthen material. Generally, vegetation accounts for less than 15 percent of total cover.

41. Deciduous Forest - Areas dominated by trees generally greater than 5 meters tall, and greater than 20 percent of total vegetation cover. More than 75 percent of the tree species shed foliage simultaneously in response to seasonal change.

42. Evergreen Forest - Areas dominated by trees generally greater than 5 meters tall, and greater than 20 percent of total vegetation cover. More than 75 percent of the tree species maintain their leaves all year. Canopy is never without green foliage.

81. Pasture/Hay - Areas of grasses, legumes, or grass-legume mixtures planted for livestock grazing or the production of seed or hay crops, typically on a perennial cycle. Pasture/hay vegetation accounts for greater than 20 percent of total vegetation.

82. Cultivated Crops - Areas used for the production of annual crops, such as corn, soybeans, vegetables, tobacco, and cotton, and also perennial woody crops such as orchards and vineyards. Crop vegetation accounts for greater than 20 percent of total vegetation. This class also includes all land being actively tilled.

The habitat map provided from the 2001 NLCD data does not provide the most current account of the habitat cover types on the additional property but uses the most current official data available from NLCD. Since the 2001 timeframe, habitat cover on the additional property has changed due to clearing of forested areas by the former owner. The following four habitat cover types were found on the additional property during the May 2008 habitat assessment.

1. **Recent Mixed Hardwood/Pine Cut-over:** Approximately 62 acres or 66 percent of the northeast part of the additional property has been timbered within the last one-to-three years.
2. **Deciduous Hardwood Forest:** Approximately three-to-five acres or 3 percent of the northwest boundary of the additional property is covered with mixed deciduous hardwood forest area and lies between two wetland drainages.
3. **Young Mixed Pine/Hardwood:** Approximately 22 to 24 acres or 23.5 percent of the additional property consist of a young mixed pine/hardwood cover type.
4. **Grassy Field:** Approximately 7 acres or 7.5 percent of the additional property consists of grassy fields and is located immediately north of the intersection of Kentucky Springs Road and Haley Drive.

The habitat map shown on Figure 4A-2 also shows the small whorled pogonia survey area inside the additional property as well as the areas that were identified as potentially suitable habitat.

4A.3 Cultural Resources Identified on NAPS Properties

Currently, there are no known historic architectural resources within the Area of Potential Effects for the NAPS site or additional property that are eligible for inclusion in or currently listed on the National Register of Historic Places. During the archaeological survey conducted in April 2008, one potentially historic site was identified which consisted of a partially collapsed log cabin. It has not yet been determined if the site is eligible for inclusion in the National Register of Historic Places. The absence of known historic properties on the additional property precludes the need for a view shed analysis.

4A.4 Cultural Resource Protection on NAPS Properties

Dominion has stated in both the ESP Application (ESP-ER Section 4.1.3) and COL Application (ER Table 1.2-1) that administrative and physical controls will be maintained to report assessments and avoid cultural resources. Dominion has continued consultation with the VDHR throughout several cultural resources assessments, and intends to preserve such cultural resources and avoid sites during ground-disturbing activities to the extent practicable. (Reference 4) These statements, along with the administrative controls, serve as Dominion's corporate commitment to protect identified historical resources and any future discovery of cultural resources.

An archaeological survey of the additional property was completed in April 2008 and one potentially historic site was identified consisting of a partially collapsed log cabin. (Reference 5) The eligibility of this historic site for the National Register of Historic Places has not yet been determined. The final archaeological survey was sent to VDHR in September 2009. In a November 2009 letter to

Dominion, VDHR concurred that the cabin is potentially eligible for inclusion in the National Register, and also that the site be avoided and preserved in place, if feasible. VDHR's expectation is for Dominion to reinitiate consultation if avoidance is deemed impractical.

4A.5 Wetlands and Surface Water

A wetlands and streams delineation survey, map, and detailed report for the additional property has been prepared and identifies nine additional non-tidal wetlands and streams within the land area southwest of NAPS. The nine wetlands and streams boundaries were identified and flagged during the wetland delineation conducted in March 2008. (Reference 1) The wetland boundaries were verified through a site review conducted by the USACE. USACE letter dated August 27, 2008 documents acceptance of the wetland boundaries on the additional property. (Reference 2)

The wetland delineation, construction use, and earth work are depicted on Figure 1.1-1. Based upon the construction utilization predicted in Figure 1.1-1, all identified wetlands will be impacted during NAPS construction. While the current construction and utilization plan has not been finalized, it appears that approximately 133,700 square feet of wetlands within the additional property will be affected. The majority of wetlands will be impacted by the spoils storage and material lay down area. The remaining impacts will be by aggregate storage area with material lay down and storage areas. This is expected to have a MODERATE impact to the wetlands in the additional property area. The survey also found the majority of wetland areas were located in valleys with intermittent or perennial streams totaling approximately 3700 linear feet that generally flowed north toward Harris Creek. Impacts to the streams are expected to be SMALL.

As a result of the construction of Unit 3, direct impacts to wetlands and streams in the area will occur. It is Dominion's practice to avoid these areas during construction where practical and minimize potential impacts when no alternative exists. As such, a mitigation plan will be developed to offset the disruption of these identified wetlands. The wetland areas to be impacted include both forested and emergent wetlands. Mitigation measures being considered to compensate for stream and wetland losses may include preservation of other onsite streams or purchasing credits from an approved mitigation bank.

Structures planned for the additional property outside of the NAPS site during the construction of Unit 3 are not expected to be permanent following the completion of construction. Structures are planned to be removed and the area would be stabilized.

4A.6 Groundwater Aquifers

Approximately two to three domestic wells will be installed on the additional property to provide water to support construction activities. The wells are expected to have a water withdrawal rate of approximately 2 gpm each.

4A.7 Conclusion

Construction impacts to the additional property area will range from SMALL to MODERATE with only roads remaining and structures expected to be removed.

4A.8 References

1. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation on Route 700 Parcels Adjacent to Haley Drive and Kentucky Springs Road," June 2008.

2. Department of the Army, Norfolk District Corps of Engineers, "Confirmation of Wetland Delineation (Harris Creek)," NAO-2008-002533, Northern Virginia Regulatory Section, August 27, 2008.

3. Davis Environmental Consultants, Inc., "Habitat Assessment for Selected Rare, Threatened and Endangered Species Near the Dominion North Anna Power Station Louisa County, Virginia," July 22, 2008.

4. Dominion, "Dominion Combined License Project, North Anna Power Station, Project Update and Archaeological Survey (2008) VDHR File No.: 2000-1210," letter to Kathleen Kilpatrick, Director, Virginia Department of Historic Resources from Eugene S. Grecheck, Vice President, Dominion, November 4, 2008.

5. The Louis Berger Group, Inc., "Archaeological Survey Dominion Combined License Project North Anna Power Station Louisa County, Virginia," June 2009.

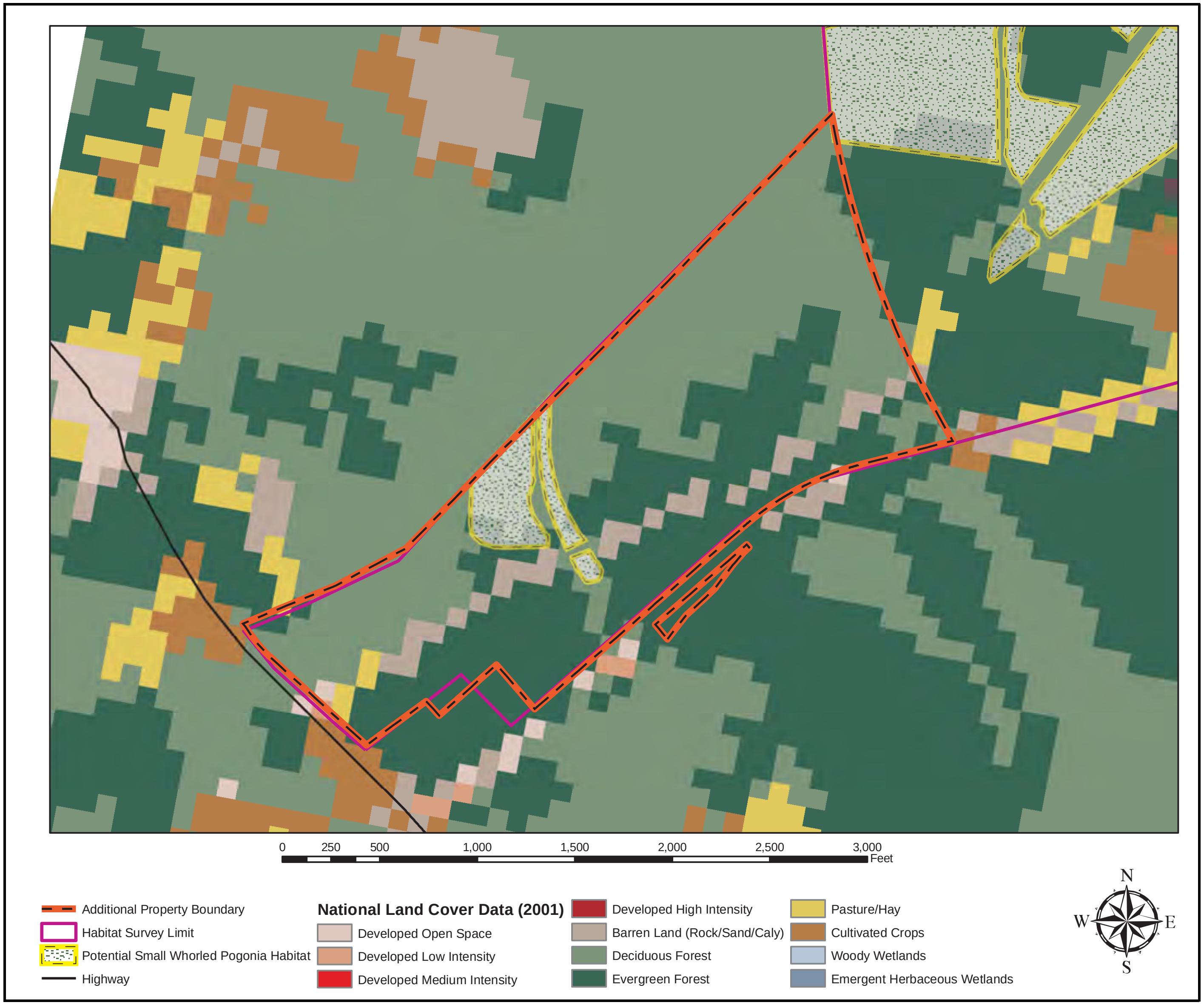
6. Commonwealth of Virginia, Department of Conservation and Recreation, Correspondence to Michael Sackschewky of Pacific Northwest National Laboratory, "Re: North Anna Power Station Unit 3-North Anna Project Site, Construction Staging Area and North Anna Ladysmith Transmission Line Corridor," September 2009.

7. Williamsburg Environmental Group, Inc., Habitat Survey for the Small Whorled Pogonia (Isotria medeoloides), North Anna Power Station, Louisa County, Virginia, November 2009.

8. Williamsburg Environmental Group Inc., "Detailed Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," August 2012.

Figure 4A-1 Deleted

Figure 4A-2 Habitat Map for Additional Property



Appendix 4B Site Separation Activities

4B.1 Summary of Planned Site Separation Activities

Dominion is making certain changes to facilities for the existing units on the NAPS site so that the operation of Units 1 and 2 will not be affected by Unit 3 construction. These activities are referred to as site separation.

Although these activities are not construction of Unit 3, environmental impacts of site separation activities (SSAs) are evaluated to determine if they could contribute to adverse cumulative impacts related to the NAPS Unit 3 project.

The following activities define the scope of required SSAs:

- Construct communication tower, telephone switch, and fiber-optic network
- Construct new fabrication shop and office facilities, and underground support utilities, i.e., electrical, mechanical
- Install sewage system modifications
- Construct fire protection and domestic water supplies to avoid Unit 3 facilities
- Modify onsite haul route
- Construct southeast security building and sally port
- Conduct general earthwork for new facilities
- Implement stormwater runoff plan alterations (near west end Unit 2 Turbine Building)
- Build new parking areas

Figure 4B-1 shows the areas on the NAPS site impacted by SSAs. This appendix addresses the impacts of these activities upon wetlands, surface water, cemeteries, archaeological sites and terrestrial and aquatic habitats as well as mitigation strategies for those areas potentially impacted by the SSAs.

4B.2 Discussion of Impacts

The primary receptors of concern for the SSAs are wetlands and surface water quality. There are three potential non-tidal wetland areas within the lands proposed for the SSAs with a total observed area of 43,952 square feet (1.01 acres) (Reference 1). As discussed below, the impacts to wetlands would be similar to those in ESP-ER Section 4.3.1.2 and the impacts to surface waters would be similar to those in ESP-ER Section 4.2.1.1.

4B.2.1 Wetlands

A new paint shop supporting the existing units will impact a small emergent wetland system.

New parking areas will be built for SSA construction and personnel supporting the existing units. Two of three identified wetland areas are adjacent to and would be impacted by these activities.

Onsite haul route modifications – The proposed haul route modifications will impact one small emergent wetland area.

The guidelines presented in ESP-ER Section 4.3.1.2 (e.g., avoidance where possible and permit attainment and compliance) will be applied to SSAs in those areas which will or may impact wetlands. As a result of avoidance, protection, and permit compliance impacts to wetlands from conducting SSAs will be SMALL.

4B.2.2 Surface Water

New support facilities – New facilities will be built in the southeast corner of the site and will require grading work adjacent to a sloping terrain above the WHTF. This work has the potential to cause impacts to surface water quality from sediment laden runoff during construction.

Onsite haul route modifications – Because of its proximity to the discharge canal this activity may allow sedimentation from construction activities to enter the WHTF via the discharge canal.

General earthwork for SSAs – The earthwork required to build the new SSAs has the potential to impact the WHTF with sediment laden runoff during construction activities.

ESP-ER Section 4.2.1.1 states "During construction of the new units, the potential would exist for sediment from the construction site to be eroded and conveyed to Lake Anna by stormwater runoff until the ESP site drainage system is installed and construction is completed. Best management practices (BMPs) described in the Virginia Erosion and Sediment Control Handbook (ESP-ER Section 4.2) would be used to control erosion and minimize the sediment load to Lake Anna in accordance with an approved erosion and sediment control plan. Best management practices may include sediment basins, sediment barriers, vegetative stabilization and filter strips, rip rap, rock filter berms, mulching, etc." These measures will be adopted during the construction-related SSAs.

4B.2.3 Aquatic Habitat

Because the SSAs are constrained to terrestrial areas of the existing site, their impacts would be bounded by those described in ESP-ER Section 4.3.2.

Because no other impacts are anticipated, mitigation measures for SSAs will include applicable mitigation described in ESP-ER Section 4.3.2.

4B.2.4 Terrestrial Habitat

Because the SSAs are constrained to the existing site, their impacts would be bounded by those described in ESP-ER Section 4.3.1.2.

However, a November 2009 plant-specific habitat survey (Reference 2) identified a potential small whorled pogonia habitat on the site. This potential habitat includes the construction backfill borrow area and the stormwater management pond (as shown in the northwest corner of Figure 4B-1) required for the general earthworks SSA. Follow-up plant-specific identification surveys, conducted during the flowering season, determined that the small whorled pogonia was not present within these habitat areas. (Reference 3) Mitigation measures for SSAs will include applicable mitigation described in ESP-ER Section 4.3.1.2.

4B.2.5 Cemeteries

Three cemeteries are identified on the NAPS site in ESP-ER Figure 2.5-18. The SSAs are constrained to areas of the site where there are no known cemeteries.

Because no impacts are anticipated, no mitigation is required.

4B.2.6 Archaeological Sites

ESP-ER Figure 2.5-17 shows the locations of areas with potential for yielding archaeological resources within the NAPS study area. The only known archaeological site within the EAB is on the western edge of the site, outside the area to be impacted by the SSAs. Dominion will maintain communications with the Virginia Department of Historic Resources (VDHR) regarding the management of the NAPS site and the potential ground-disturbing activities in areas that have the potential for containing historic and/or archaeological artifacts.

Because no other impacts are anticipated that differ from those in the ESP-ER, mitigation measures for SSAs will include applicable mitigation described in ESP-ER Section 4.1.3 and ESP-ER Table 4.6-1.

4B.2.7 Socioeconomic Impacts

The size of the workforce that will be required to conduct SSAs will be much smaller than the workforce that will be required to construct NAPS Unit 3. In addition, SSA construction will occur prior to the peak of Unit 3 construction. Because of this, the socioeconomic impacts associated with the SSAs will be proportionately smaller than the socioeconomic impacts for construction of Unit 3.

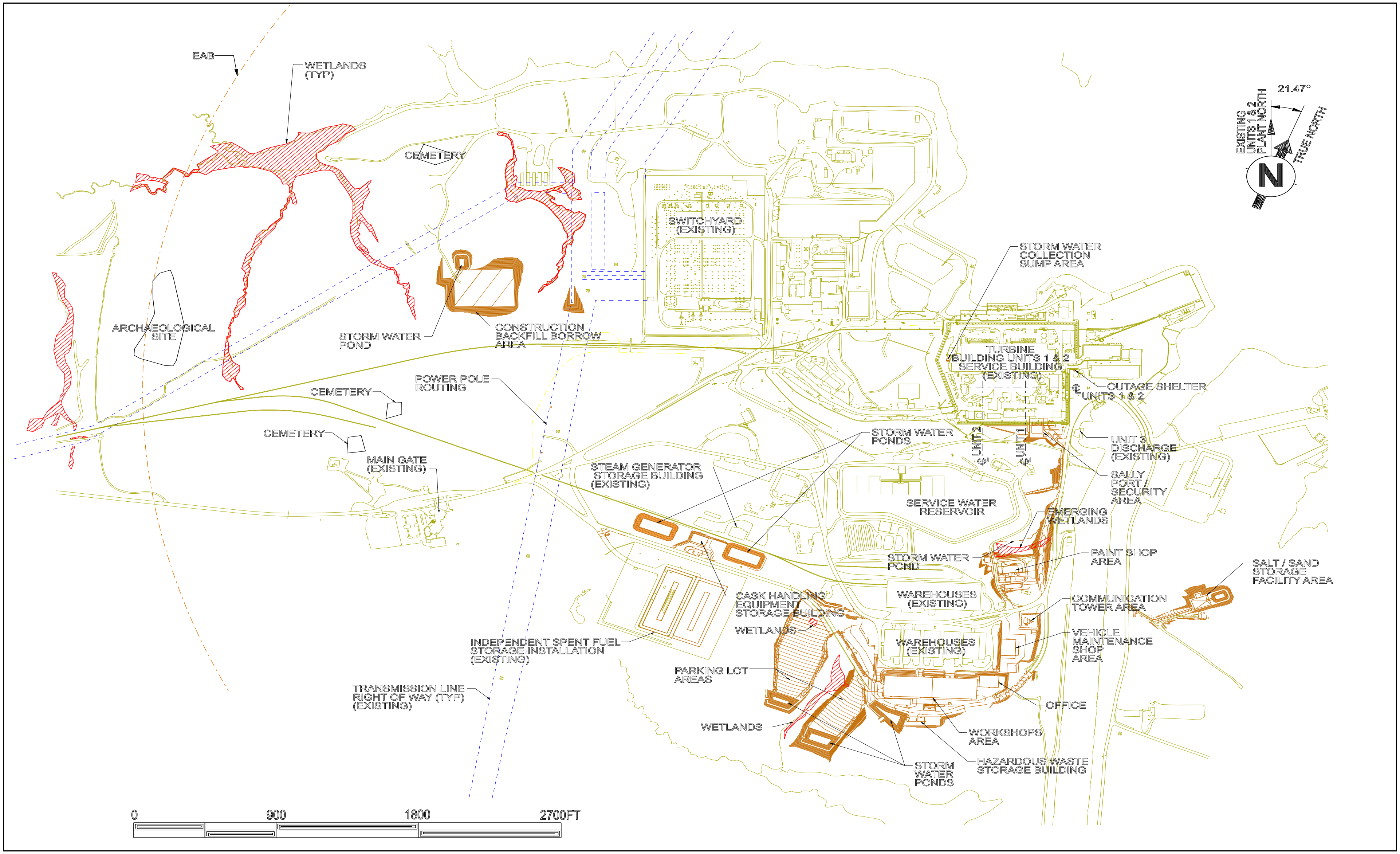
Section 4B.4 References

1. EA Engineering, Science, and Technology, Inc., "Dominion North Anna Power Station Wetland Delineation for Site Separation Projects," June 2008.

2. Williamsburg Environmental Group, Inc, "Habitat Survey for the Small Whorled Pogonia (Isotria medeoloides), North Anna Power Station, Louisa County, Virginia," November 2009.

3. Williamsburg Environmental Group Inc., "Detailed Survey for the Small Whorled Pogonia (*Isotria medeoloides*) North Anna Power Station, Louisa County, Virginia," August 2012.

Figure 4B-1 Site Separation Activities



Chapter 5 Environmental Impacts of Station Operation

5.1 Land-Use Impacts (Operations)

The information for this section is provided in ESP-ER Section 5.1 and associated impacts are resolved as SMALL in FEIS Section 5.1. Supplemental information is provided in Section 5.1.2 below.

5.1.1 The Site and Vicinity

No new and significant information has been identified for this section.

5.1.2 Transmission Corridors and Offsite Areas

As discussed in Section 3.7, the new 500 kV transmission line required in connection with Unit 3 will be installed along the existing NAPS-to-Ladysmith corridor. As discussed in Section 5.6, the impacts of maintenance practices, visual impacts, shock, noise, or electro-magnetic fields would not change. Existing corridor access routes would be used. Therefore, no changes in or new restrictions to land use would result, and offsite land-use impacts will remain SMALL. No new mitigation measures or controls are warranted.

5.1.3 Historic Properties

No new and significant information has been identified for this section.

5.2 Water-Related Impacts

The information for this section is provided in ESP-ER Section 5.2 and associated impacts, with the exception of water quality impacts, are resolved in FEIS Sections 5.3 and 7.3 as SMALL during normal water years and temporarily MODERATE during severe droughts. Supplemental information regarding water quality impacts is provided in Section 5.2.2 below. In addition, supplemental information on the hydrologic alterations, plant water supply and water-use impacts is provided in Section 5.10.1 that addresses specifically the mitigating actions based on the results of the IFIM study.

5.2.1 Hydrologic Alterations and Plant Water Supply

Supplemental information on hydrologic alterations and plant water supply is provided in Section 5.10.1.3 that addresses specifically the lake mitigating actions based on the results of the IFIM study.

5.2.2 Water-Use Impacts

Section 3.3 describes water treatment and Section 3.6 describes nonradioactive effluents, including sanitary waste and cooling tower blowdown. Section 3.6 identifies the expected constituents that would be contained in the effluents discharged to the WHTF (from Units 1 and 2, as well as Unit 3) and compares them to Virginia Surface Water Quality Criteria (Reference), as applicable.

The effluent from Unit 3 would include circulating water and service water system blowdown (which have been concentrated due to evaporation from the systems) and other system backwashes, rejects and drains (which have the same concentrations as the lake water). Concentrations of various constituents in the Unit 3 effluent would be diluted with a much larger volume of water in the WHTF. Operation of a dechlorination system would neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir.

As described in Section 3.6, the results of the effluent analysis demonstrate that for all postulated case/condition combinations, the constituent concentrations that are discharged to the lake would remain within the existing VPDES permit water quality criteria with the exception of two constituents: copper and tributyltin.

Both of these constituents are already present in the lake water at concentrations equal to or greater than the current VPDES water quality criteria. The presence of both of these constituents is unrelated to the operation of the existing Units 1 and 2, and Unit 3 would not contribute to the amounts already existing in the lake. Additionally the increase in concentrations of these constituents in the discharge to the WHTF attributable to the operation of Unit 3 would be essentially immeasurable using current VDEQ-approved analytical methods.

Dominion analyzes station discharge for these constituents and characteristics as required by the VPDES permit for Units 1 and 2. Similar sampling and analyses would be performed in accordance with the VPDES permit for Unit 3.

Supplemental information on water-use impacts is provided in Section 5.10.1.3 that addresses specifically the lake mitigating actions based on the results of the IFIM study.

Section 5.2 Reference

Commonwealth of Virginia, State Water Control Board, "Virginia Water Quality Standards," 9 VAC 25-260 (et seq.), August 14, 2007.

5.3 Cooling System Impacts

The information for this section is provided in ESP-ER Section 5.3, and associated cooling system impacts are resolved as SMALL in FEIS Sections 5.4 and 5.8.

For the ESP-ER, an analysis was performed for the wet cooling towers to describe the plume impacts including: fogging, icing, salt deposition and visible plumes from traditional (e.g., non plume abated) wet cooling towers. The results of that analysis are documented in ESP-ER Section 5.3. In ESP-ER Section 5.3.3.1, a commitment was made to conduct a confirmatory evaluation of the fogging, icing, and salt deposition to show that the values in the ESP-ER remain bounding, when specific cooling tower and plant designs had been selected. To satisfy this commitment, a confirmatory analysis of the plume impacts associated with the closed-cycle, combination dry and wet towers has been performed, using manufacturer's data representative of the Unit 3 cooling towers' design. The methodology used is the same as that used in the ESP-ER analysis. The confirmatory analysis concluded that the plume impacts reported in the ESP-ER, associated with the main cooling towers, remain bounding for fogging, icing and salt deposition.

Supplemental information is provided in Section 5.10.1 that addresses specifically the mitigating actions resulting from the IFIM study.

5.4 Radiological Impacts of Normal Operation

The information for this section is provided in the ESP-ER Section 5.4, and associated impacts are resolved as SMALL in FEIS Section 5.9. However, ESP-ER Section 5.4 includes a commitment to verify the maximum occupational dose at the time of selection of the reactor design. The commitment is addressed in Section 5.4.2.

5.4.1 Exposure Pathways

No new and significant information has been identified for this section.

5.4.2 Radiation Doses to Members of the Public

In the ESP-ER, the maximum annual occupational dose to the workers from normal operation of proposed Unit 3 was estimated to be 150 person-rem. Using ESBWR-specific data, the annual occupational dose has been calculated as shown in DCD Table 12.4-1 to be 84.5 person-rem. The ESP-ER value for occupational dose bounds the dose calculated for the ESBWR, and thus the impact due to occupation worker dose remains SMALL and no new mitigation measures or controls are warranted.

5.4.2.1 Liquid Pathway Doses

ESP-ER Table 5.4-6 presented the composite release activities of liquid effluents for a single new unit. These composite activities were obtained by taking the maximum activity for each isotope from multiple reactor designs. ESBWR-specific liquid effluent release activities are presented in

Table 5.4-1 and compared to the ESP-ER composite release activities. Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity. "NP" denotes isotopes which are not present in ESBWR liquid effluents.

There are increases in liquid effluent release activities for some radioisotopes associated with normal operation of Unit 3 as compared to the composite release activities presented in the ESP-ER. However, the total liquid effluent release activity of Unit 3 is less than the total ESP-ER composite release activity.

ESP-ER Table 5.4-10 provided the total body and organ doses to the maximally exposed individual (MEI) resulting from liquid and gaseous effluent releases of a single new unit. These calculated doses were determined to be within the design objectives of 10 CFR 50, Appendix I. Using design-specific release activities of liquid effluents from Unit 3, the total annual doses to the MEI from liquid effluents are calculated and presented in Table 5.4-2. The total annual doses from liquid effluents were calculated using the same methodologies and parameters (with the exception of release activity) as those used in ESP-ER annual MEI dose calculations.

As shown in Table 5.4-2, the annual doses to the MEI from some liquid effluent pathways are consistently lower than those calculated and presented in the ESP-ER. Therefore, the dose impacts to the MEI remain SMALL, and no new mitigation measures or controls are warranted.

5.4.2.2 Gaseous Pathway Doses

ESP-ER Table 5.4-7 presented the composite release activities of gaseous effluents for a single new unit. These composite activities were obtained by taking the maximum activity for each isotope from multiple reactor designs. ESBWR-specific gaseous effluent release activities are presented in Table 5.4-3 and are compared to ESP-ER composite release activities. Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity. "NP" denotes isotopes which are not present in ESBWR gaseous effluents.

The total annual doses to the MEI from gaseous effluents have been re-calculated using the ESBWR-specific gaseous release activities and the same methodologies and parameters as those used in ESP-ER calculations, with the exception of MEI locations. As discussed in Section 2.7, the MEI locations for the vegetable garden, residential, and meat animal receptors have changed. A single, bounding location, has been selected for these receptors and the doses from the garden, residential, and meat animal pathways are summed to arrive at the total dose at this location. For Reactor Building releases, the χ/Q values are at 0.74 mile NNE from the facility boundary and the D/Q values are at the same distance in the NNE direction. For Reactor Building releases, the maximum χ/Q site boundary MEI location (0.88 mile NNE of the plant boundary) and maximum D/Q site boundary location (0.62 mile in the south direction) are the same as were used in the ESP-ER. Table 2.7-2 summarizes the distances and directions from the Reactor Building, Turbine Building, Radwaste Building, and the circulating water cooling tower to receptors of interest, as well as the associated χ/Q and D/Q values. The results of the total annual dose calculations are provided in Table 5.4-4.

Table 5.4-5 shows that the annual total body, maximum organ, and skin doses to the MEI are lower than those calculated and presented in the ESP-ER. Therefore, the impact of gaseous pathway doses remains SMALL, and no mitigation measures or controls are warranted.

5.4.2.3 **Direct Radiation from Station Operation**

As indicated in ESP-ER Section 5.4.1.3, the offsite dose due to direct radiation from the new and existing units will be negligible. However, an assumed value of 1 mrem/yr is included in Table 5.4-6 to account for the dose to the MEI at the nearest residence from operation of Units 1 and 2. Another source of direct radiation is the NAPS ISFSI, which is located south of the proposed Unit 3 site. The distance from the ISFSI to the site boundary is 2500 ft. The annual direct radiation contribution at the site boundary from the ISFSI is no more than 3.6 mrem/yr. The distance from the ISFSI to the nearest residence is 2860 ft. Since this is farther away than the site boundary, the direct radiation dose to the MEI at the nearest residence would be less than 3.6 mrem/yr.

5.4.3 **Impacts to Members of the Public**

ESP-ER Table 5.4-11 demonstrated that the total site liquid and gaseous effluent doses resulting from the normal operation of the two existing North Anna units and two proposed new units would be well within the regulatory limits of 40 CFR 190. ESP-ER Table 5.4-12 presented the collective doses attributable to two new units for the population within 50 miles of the proposed ESP site. Accounting for changes in the liquid and gaseous effluent release activities, identified in Table 5.4-1 and Table 5.4-3, the total annual doses to the MEI and the total population doses resulting from the proposed Unit 3 liquid and gaseous effluents are calculated and presented in Table 5.4-6 and Table 5.4-7, respectively. These total annual doses to the MEI and to the population were calculated using the same methodologies and parameters (with the exception of the release activities) as those used in ESP-ER.

As shown in Table 5.4-4 some of the annual doses to the MEI resulting from Unit 3 gaseous effluents are higher than those in the ESP-ER. However, as shown in Table 5.4-6, even when direct radiation doses from operation of the ISFSI and Units 1 and 2 are included with the gaseous effluent doses to the MEI, the total site doses are below regulatory limits, the impact to members of the public remains SMALL, and no mitigation measures or controls are warranted.

As shown in Table 5.4-7, the annual dose to the population within 50 miles resulting from Unit 3 liquid and gaseous effluents are lower than those calculated for a single unit and presented in the ESP-ER. Therefore, the liquid and gaseous effluent doses to the population provided in the ESP-ER are bounding, the impact to members of the public remains SMALL, and no mitigation measures or controls are warranted.

5.4.4 Impacts to Biota Other Than Members of the Public

ESP-ER Table 5.4-16 presented the maximum calculated doses to biota from liquid and gaseous effluents. In FEIS Section 5.9.5.3, the NRC staff concluded that, based on Dominion calculations, the impacts to the biota would be SMALL, and mitigation is not warranted. The maximum doses to biota resulting from proposed Unit 3 liquid and gaseous effluents have been calculated using the same methodologies in the ESP-ER, accounting for the changes in liquid and gaseous effluent release activities. These doses are provided in Table 5.4-8.

As shown in Table 5.4-8, the annual doses to the biota from liquid and gaseous effluent releases are lower than those calculated and presented in ESP-ER. Therefore, the liquid and gaseous effluent biota doses in the ESP-ER are still bounding, and impact from doses on biota other than members of the public remains SMALL, and no mitigation measures and controls are warranted.

5.4.5 Conclusion

As discussed previously, the impacts of radiological exposure to the MEI, the population, occupational workers, and biota resulting from normal operation of Unit 3 will be SMALL, and mitigation measures and controls are not warranted.

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
H-3	8.5E+02	**1.4E+01**
C-14	4.4E-04	NP
Na-24	3.5E-03	**4.2E-03**
P-32	6.6E-04	3.5E-04
Cr-51	2.1E-02	1.1E-02
Mn-54	2.8E-03	1.3E-04
Mn-56	4.2E-03	1.0E-03
Fe-55	6.4E-03	1.9E-03
Fe-59	2.0E-04	6.0E-05
Co-56	5.7E-03	NP
Co-57	7.9E-05	NP
Co-58	3.4E-03	3.7E-04
Co-60	1.0E-02	7.5E-04
Ni-63	1.5E-04	NP
Cu-64	8.2E-03	**1.0E-02**
Zn-65	7.5E-04	3.7E-04
Zn-69m	6.0E-04	**7.5E-04**
Br-83	7.5E-05	**1.0E-04**
Br-84	2.0E-05	NP
Rb-88	2.7E-04	NP
Rb-89	4.8E-05	NP
Sr-89	3.6E-04	1.9E-04
Sr-90	3.8E-05	1.0E-05
Sr-91	9.8E-04	9.5E-04
Sr-92	8.8E-04	2.3E-04
Y-90	3.4E-06	NP
Y-91m	1.0E-05	NP
Y-91	2.4E-04	1.2E-04
Y-92	6.6E-04	**8.7E-04**

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Y-93	9.8E-04	**1.0E-03**
Zr-95	1.0E-03	1.0E-05
Nb-95	1.9E-03	1.0E-05
Mo-99	3.9E-03	2.5E-03
Tc-99m	5.1E-03	4.6E-03
Ru-103	4.9E-03	4.0E-05
Ru-105	1.0E-04	**1.3E-04**
Ru-106	7.4E-02	NP
Rh-103m	4.9E-03	NP
Rh-106	7.4E-02	NP
Ag-110m	1.1E-03	NP
Ag-110	1.4E-04	NP
Sb-124	6.8E-04	NP
Te-129m	1.4E-04	7.0E-05
Te-129	1.5E-04	NP
Te-131m	1.0E-04	8.0E-05
Te-131	3.0E-05	NP
Te-132	2.4E-04	1.0E-05
I-131	1.4E-02	6.2E-03
I-132	2.8E-03	9.3E-04
I-133	2.4E-02	**3.0E-02**
I-134	1.9E-03	4.0E-05
I-135	8.2E-03	7.1E-03
Cs-134	9.9E-03	5.7E-04
Cs-136	1.2E-03	3.5E-04
Cs-137	1.3E-02	1.5E-03
Cs-138	2.1E-04	NP
Ba-137m	1.2E-02	NP
Ba-139	2.5E-05	**3.0E-05**

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Ba-140	5.5E-03	6.9E-04
La-140	7.4E-03	NP
La-142	2.5E-05	2.0E-05
Ce-141	1.3E-04	6.0E-05
Ce-143	1.9E-04	3.0E-05
Ce-144	3.2E-03	NP
Pr-143	1.4E-04	7.0E-05
Pr-144	3.2E-03	NP
W-187	2.1E-04	2.0E-04
Np-239	1.4E-02	9.3E-03
Total w/o H-3	3.7E-01	9.9E-02
Total w/ H-3	8.5E+02	1.4E+01

Note 1: Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity.
Note 2: "NP" denotes isotopes which are "not present" in ESBWR liquid effluents.

Table 5.4-2 Comparison of Annual Doses to MEI from Unit 3 Liquid Effluent at Lake Anna

	ESP Dose (mrem/yr)			Unit 3 Dose (mrem/yr)		
Pathway	**Total Body**	**Thyroid**	**Bone**	**Total Body**	**Thyroid**	**Bone**
Fish	5.1E-01	N/A	2.3E+00	6.5E-02	N/A	1.0E+00
Invertebrate	6.6E-02	N/A	1.5E-01	6.9E-03	N/A	5.4E-02
Drinking	2.0E-01	6.5E-01	2.7E-02	4.0E-03	2.5E-01	4.5E-03
Shoreline	3.0E-02	3.0E-02	3.0E-02	2.5E-03	2.5E-03	2.5E-03
Swimming	3.2E-04	3.2E-04	3.2E-04	1.2E-04	1.2E-04	1.2E-04
Boating	4.0E-04	4.0E-04	4.0E-04	1.5E-04	1.5E-04	1.5E-04
Total	8.1E-01	6.8E-01	2.5E+00	7.9E-02	2.6E-01	1.1E+00
Age group receiving maximum dose	Adult	Infant	Child	Adult	Infant	Child

Note 1: The organ receiving the maximum dose is the child's bone.

Note 2: There are no infant doses for the vegetable and meat pathways because infants do not consume these foods. "N/A" denotes "not applicable."

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
H-3	3.5E+03	2.5E+02
C-14	1.2E+01	**1.4E+01**
Na-24	4.4E-03	1.6E-04
P-32	1.0E-03	4.1E-05
Ar-41	3.0E+02	**3.8E-02**
Cr-51	3.8E-02	7.2E-03
Mn-54	5.9E-03	**8.2E-03**
Mn-56	3.8E-03	3.2E-04
Fe-55	7.1E-03	1.4E-03
Fe-59	8.9E-04	**1.1E-03**
Co-57	8.2E-06	NP
Co-58	2.3E-02	2.2E-03
Co-60	1.4E-02	**1.8E-02**
Ni-63	7.1E-06	1.4E-06
Cu-64	1.1E-02	2.0E-04
Zn-65	1.2E-02	**1.7E-02**
Kr-83m	1.3E-03	**2.3E-03**
Kr-85m	3.6E+01	1.8E+01
Kr-85	4.1E+03	1.4E+02
Kr-87	4.9E+01	3.9E+01
Kr-88	7.4E+01	5.7E+01
Kr-89	4.7E+02	3.7E+02
Kr-90	4.2E-04	NP
Rb-89	4.7E-05	5.4E-06
Sr-89	6.2E-03	**8.3E-03**
Sr-90	1.2E-03	5.0E-05
Sr-91	1.1E-03	2.0E-04
Sr-92	8.6E-04	1.3E-04

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Y-90	5.0E-05	2.4E-06
Y-91	2.6E-04	5.1E-05
Y-92	6.8E-04	1.0E-04
Y-93	1.2E-03	2.2E-04
Zr-95	1.7E-03	**2.5E-03**
Nb-95	9.2E-03	**1.4E-02**
Mo-99	6.5E-02	**9.3E-02**
Tc-99m	3.3E-04	6.5E-05
Ru-103	3.8E-03	**5.8E-03**
Ru-106	7.8E-05	4.3E-06
Rh-103m	1.2E-04	1.0E-07
Rh-106	2.1E-05	1.4E-10
Ag-110m	2.2E-06	**4.6E-06**
Sb-124	2.0E-04	**3.0E-04**
Sb-125	6.1E-05	NP
Te-129m	2.4E-04	4.9E-05
Te-131m	8.3E-05	1.6E-05
Te-132	2.1E-05	4.1E-06
I-131	5.1E-01	5.0E-01
I-132	2.4E+00	**2.5E+00**
I-133	1.9E+00	**2.4E+00**
I-134	4.1E+00	4.0E+00
I-135	2.6E+00	**3.2E+00**
Xe-131m	1.8E+03	4.1E+00
Xe-133m	8.7E+01	5.2E-03
Xe-133	4.6E+03	1.1E+03
Xe-135m	7.7E+02	6.1E+02
Xe-135	8.2E+02	7.5E+02

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Xe-137	9.8E+02	7.8E+02
Xe-138	7.8E+02	6.3E+02
Xe-139	5.3E-04	NP
Cs-134	6.8E-03	**1.0E-02**
Cs-136	6.5E-04	**8.3E-04**
Cs-137	1.0E-02	**1.5E-02**
Cs-138	1.9E-04	2.3E-05
Ba-140	3.0E-02	**4.4E-02**
La-140	2.0E-03	3.8E-04
Ce-141	1.0E-02	**1.5E-02**
Ce-144	2.1E-05	4.3E-06
Pr-144	2.1E-05	4.9E-09
W-187	2.1E-04	3.8E-05
Np-239	1.3E-02	2.4E-03
Total w/o H-3	1.5E+04	4.5E+03
Total w/ H-3	1.8E+04	4.8E+03

Note: "NP" denotes isotopes which are "not present." Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity. Unit 3 H-3 activity includes the contribution from cooling tower evaporation. Since Lake Anna serves as the source of makeup water for the Unit 3 cooling tower, it is assumed that the tritium in Lake Anna is released to the environment as gaseous effluent via cooling tower evaporation. The maximum tritium concentration in Lake Anna from the operation of Units 1, 2, and 3 is 5.6E-06 µCi/ml. Multiplying this concentration by the maximum circulating water cooling tower evaporation rate (and associated drift rate) of 16,135 gpm or 3.21E+13 ml/yr yields a release of 1.8E+02 Ci/yr. Adding this value to the normal ESBWR release of 7.2E+01 Ci/yr (DCD Table 12.2-16) results in a total tritium release of 2.5E+02 Ci/yr.

Table 5.4-4 Gaseous Pathway Doses (mrem/yr) to the MEI

		ESP-ER			Unit 3		
Location	**Pathway**	**Total Body**	**Thyroid**	**Skin**	**Total Body**	**Thyroid**	**Skin**
Site Boundary (0.88 mi ESE for ESP-ER; 0.88 mi NNE/ESE, 0.34 mi W for this ER)	Plume	2.1E+00	N/A	6.2E+00	2.8E-01	**2.8E-01**	5.0E-01
	Inhalation						
	Adult	3.0E-01	1.6E+00	N/A	2.7E-02	1.0E-01	N/A
	Teen	3.1E-01	2.0E+00	N/A	2.7E-02	1.3E-01	N/A
	Child	2.7E-01	2.3E+00	N/A	2.4E-02	1.5E-01	N/A
	Infant	1.6E-01	2.0E+00	N/A	1.4E-02	1.3E-01	N/A
Nearest Garden (0.94 mi NE for ESP-ER; 0.74 mi NNE/ESE for this ER)	Vegetable						
	Adult	4.4E-01	4.9E+00	N/A	8.0E-02	1.6E+00	N/A
	Teen	5.7E-01	6.6E+00	N/A	8.9E-02	2.2E+00	N/A
	Child	1.1E-00	1.3E+01	N/A	1.3E-01	4.2E+00	N/A
Nearest Residence (0.96 mi NNE for ESP-ER; 0.74 mi NNE/ESE for this ER)	Plume	1.4E+00	N/A	4.0E+00	3.2E-01	**3.2E-01**	5.9E-01
	Inhalation						
	Adult	2.0E-01	1.0E+00	N/A	2.7E-02	1.2E-01	N/A
	Teen	2.0E-01	1.3E+00	N/A	2.7E-02	1.5E-01	N/A
	Child	1.8E-01	1.5E+00	N/A	2.4E-02	1.8E-01	N/A
	Infant	1.0E-01	1.3E+00	N/A	1.4E-02	1.5E-01	N/A
Nearest Meat Animal (1.37 mi SE for ESP-ER; 0.74 mi NNE/ESE for this ER)	Meat						
	Adult	6.7E-02	1.5E-01	N/A	1.2E-02	6.5E-02	N/A
	Teen	4.9E-02	1.1E-01	N/A	7.2E-03	4.6E-02	N/A
	Child	7.9E-02	1.7E-01	N/A	9.2E-03	6.9E-02	N/A
Nearest Garden/ Residence/ Meat Animal (Varies for ESP-ER; 0.74 mi NNE/ESE for this ER)	All						
	Adult	1.6E+00	4.9E+00	4.0E+00	4.3E-01	2.1E+00	5.9E-01
	Teen	1.6E+00	6.6E+00	4.0E+00	4.4E-01	2.7E+00	5.9E-01
	Child	1.6E+00	1.3E+01	4.0E+00	4.8E-01	4.7E+00	5.9E-01
	Infant	1.5E+00	1.3E+00	4.0E+00	3.3E-01	4.7E-01	5.9E-01

Table 5.4-4 Gaseous Pathway Doses (mrem/yr) to the MEI

Notes:

1. There are no infant doses for the vegetable and meat pathways because infants do not consume these foods.
2. "N/A" denotes "not applicable."
3. For Unit 3, the doses shown for "nearest garden/residence/meat animal" location are the sum of garden, residence, and meat animal doses at 0.74 mi NNE for releases from Reactor and Turbine Buildings and 0.74 mi ESE for releases from Radwaste Building and circulating water hybrid cooling tower. For ESP-ER, these doses are the maximum of garden, residence, and meat animal doses at 0.94 mi NE, 0.96 mi NNE, and 1.37 mi SE, respectively. The site boundary and residence plume doses include ground shine contribution. For Unit 3, the site boundary doses are the sum of the maximum from each release point regardless of distance and direction (0.88 mi NNE for Reactor and Turbine Buildings, 0.88 mi ESE for Radwaste Building, 0.34 mi W for cooling tower).
4. The maximum (child) bone dose for Unit 3 from all gaseous effluent pathways is shown in Table 5.4-6.

Table 5.4-5 Comparison of Annual Doses to the MEI from Gaseous Effluents

Type of Dose	ESP-ER 1 New Unit (MEI Location)	Unit 3 (MEI Location)	10 CFR 50 Appendix I Limit
Gamma Air (mrad/yr)	3.2 (Site Boundary)	2.7E-01 (Residence)	10
Beta Air (mrad/yr)	4.8 (Site Boundary)	2.5E-01 (Residence)	20
Total Body (mrem/yr)	2.4 (Site Boundary)	3.2E-01 (Residence)	5
Skin (mrem/yr)	6.2 (Site Boundary)	5.9E-01 (Residence)	15
Iodine and Particulates – Maximum Organ (mrem/yr)	12 (Garden)	4.4E+00 (Residence/ Garden/ Meat Animal)	15

Table 5.4-6 Comparison of Site Doses (mrem/yr) to the MEI

Type of Dose	ESP Site Total (1)(4)	Unit 3			Existing Units (2)(4)	Site Total (3)	40 CFR 190 Limit
		Liquid	Gaseous	Total			
Total Body (mrem/yr)	6.8	7.9E-02	4.8E-01	5.6E-01	5.0E+00	5.5E+00	25
Thyroid (mrem/yr)	27	2.6E-01	4.7E+00	5.0E+00	5.1E+00	1.0E+01	75
Bone (mrem/yr)	12	1.1E+00	5.5E-01	1.6E+00	5.1E+00	6.8E+00	25

Notes:

1. The ESP site total doses are for two new units and the two existing units, and do not include a dose contribution from the ISFSI.
2. The doses from existing units include contributions from liquid and gaseous effluents (0.37 mrem), ISFSI (3.6 mrem), and an assumed dose of 1 mrem/yr due to direct radiation from the existing units.
3. This site total dose includes the Unit 3 total dose and the dose from the existing units.
4. The effluent dose from ESP-ER Section 5.4, Reference 11, is a critical organ dose that is applied as the thyroid and bone dose.

Table 5.4-7 Collective Total Body (Population) Doses (person-rem/yr) Within 50 Miles

	ESP-ER 1 New Unit	Unit 3
Liquid	8.6E+00	8.4E-01
Noble Gases (Gaseous)	3.5E+00	5.7E-01
Iodines and Particulates (Gaseous)	1.4E+00	1.2E+00
H-3 and C-14 (Gaseous)	1.4E+01	2.7E+00
Total	2.8E+01	5.3E+00
Natural Background	9.2E+05	9.2E+05

Notes:

1. ESP doses are based on data from ESP-ER Tables 2.5-8, 5.4-1, and 5.4-3.
2. The corresponding collective thyroid doses for Unit 3 are 9.9E-01 person-rem/year from liquid effluents and 25 person-rem/year from gaseous effluents.
3. The long-term χ/Q and D/Q values used in deriving Unit 3 collective doses from routine gaseous effluent releases within 50 miles of the plant are shown in Tables 2.7-5 to 2.7-12.

Table 5.4-8 Comparison of Annual Doses (mrad/yr) to Biota from Liquid and Gaseous Effluent

Biota Effluents	ESP-ER		Unit 3	
	Liquid	Gaseous	Liquid	Gaseous
Fish	9.7E+00	N/A	2.8E+00	N/A
Invertebrates	4.6E+01	N/A	9.3E+00	N/A
Algae	5.4E+01	N/A	1.4E+01	N/A
Muskrat	4.3E+01	3.4E+01	1.8E+01	3.4E+00
Raccoon	4.9E+00	3.4E+01	5.2E-01	3.4E+00
Heron	5.4E+01	3.4E+01	8.3E+00	3.4E+00
Duck	4.3E+01	3.4E+01	1.8E+01	3.4E+00

5.5 Environmental Impact of Waste

The information for this section is provided in ESP-ER Section 5.5. Supplemental information is provided in Section 5.5.1 below.

5.5.1 Nonradioactive-Waste-System Impacts

No new and significant information has been identified for this section, with the exception of the sanitary waste system, as discussed below.

The ESP-ER described that sewage from new units would be combined with the sanitary sewage from Units 1 & 2 for treatment. As discussed in Section 3.6, it has since been determined that sanitary sewage from Unit 3 would be treated in a new dedicated sanitary sewage waste treatment system. This new system would be similar to sanitary sewage treatment plants typically used for industrial applications. These sanitary waste plants have proven performance and substantial operational history.

Sanitary wastes from this new system would be managed on site and disposed of off site in compliance with applicable laws, regulations, and permit conditions imposed by federal, Virginia, and local agencies.

Impacts associated with treatment of sanitary waste from operation of Unit 3 will be SMALL and no mitigation is warranted.

5.5.2 Mixed Waste Impacts

No new and significant information has been identified for this section.

5.5.3 Conclusions

Impacts associated with treatment of sanitary waste from operation of Unit 3 will be SMALL and no mitigation is warranted.

5.6 Transmission System Impacts

The information for this section is provided in ESP-ER Section 5.6 and associated impacts, other than the effects of electro-magnetic fields (EMFs) are resolved as SMALL in FEIS Sections 5.1.2 and 5.4.1.5. Supplemental information is provided below to address the impacts of the new transmission line for Unit 3 and the unresolved FEIS issue on EMF exposure from transmission system operations.

5.6.1 Terrestrial Ecosystems

Maintenance practices for the existing NAPS transmission corridors are described in ESP-ER Sections 5.6.1.1 and 5.6.1.2. The new transmission line would be installed in the existing NAPS-to-Ladysmith corridor and would not result in changes to these practices. Therefore, impacts on terrestrial ecosystems from operation of the new transmission line will be SMALL. No mitigation measures or controls are warranted.

5.6.2 Aquatic Ecosystems

Maintenance practices for the existing NAPS transmission corridors are described in ESP-ER Sections 5.6.2.1 and 5.6.2.2. The effect of these procedures is described in ESP-ER Section 5.6.2. The new transmission line would not result in changes to these practices. Therefore, impacts on aquatic ecosystems from operation of the new transmission line will be SMALL. No mitigation measures or controls are warranted.

5.6.3 Impacts to Members of the Public

This section discusses the potential impacts on members of the public from electrical shock, EMF exposure, noise, and aesthetics associated with transmission system operations.

5.6.3.1 Electrical Shock

The new transmission line would be designed to ensure that steady-state short-circuit discharge currents from both the existing lines and additional line are no greater than 5 milliamperes, for the limiting case, per the NESC. Thus, potential electrical shock impacts to members of the public from the transmission lines would be SMALL.

5.6.3.2 Electromagnetic Field Exposure

FEIS Sections 5.8.5 and 7.7 state that the NRC staff does not consider potential impact of chronic effects of electromagnetic fields as significant. However, because available evidence was inconclusive, this issue was not resolved. As discussed below, the evidence remains inconclusive but continues to suggest that the impact is insignificant.

In 1996, after 17 years of research that examined more than 500 studies, the National Research Council released the results of a study that stated, "the conclusion of the committee is that the current body of evidence does not show that exposure to these fields presents a human-health hazard." Furthermore the report added there is no conclusive evidence that EMF plays a role in the development of cancer, or reproductive or other abnormalities in humans. (Reference 1)

As part of The World Health Organization (WHO) International EMF Project, in 1997 a working group of 45 scientists from around the world surveyed the evidence for adverse EMF health effects. Regarding health effects other than cancer, the WHO scientists reported that the epidemiological studies "do not provide sufficient evidence to support an association between extremely-low-frequency magnetic-field exposure and adult cancers, pregnancy outcome, or neurobehavioural disorders." (Reference 2)

The American Physical Society (APS) represents thousands of U.S. physicists. In response to the National Institute of Environmental Health Sciences (NIEHS) Working Group's conclusion that EMF is a possible human carcinogen, the APS executive board voted in 1998 to reaffirm its 1995 opinion that there is "no consistent, significant link between cancer and power line fields."

A 1999 NIEHS report (Reference 3) contains the following conclusion:

> The NIEHS concludes that ELF-EMF (extremely low frequency-electromagnetic field) exposure cannot be recognized as entirely safe because of weak scientific evidence that exposure may pose a leukemia hazard. In our opinion, this finding is insufficient to warrant aggressive regulatory concern. However, because virtually everyone in the United States uses electricity and therefore is routinely exposed to ELF-EMF, passive regulatory action is warranted such as a continued emphasis on educating both the public and the regulated community on means aimed at reducing exposures. The NIEHS does not believe that other cancers or non-cancer health outcomes provide sufficient evidence of a risk to currently warrant concern.

Although studies continue to be conducted and additional information is published regarding the effects of exposure to EMF (References 4 and 5), there continues to be no conclusive evidence of a link between EMF and the development of cancer, or reproductive or other abnormalities in humans. Thus, impacts to members of the public attributable to EMF exposure from transmission system operations will be SMALL. No mitigation measures or controls are warranted.

5.6.3.3 **Noise**

The noise levels resulting from transmission system operations would be in accordance with the state and local code requirements. Actual decibel noise levels would be minimized by proper sizing of conductors and the use of corona-free hardware. Thus, the impacts to the public attributable to noise from the transmission system operations will be SMALL, and no mitigation measures or controls are warranted.

5.6.3.4 **Visual Impacts**

As stated in Section 3.7, the new towers are expected to be about 10 percent taller, but not more than 20 feet taller than the existing towers, and thus would not have a significantly greater visual impact. Further, the visual impacts of the new line would be mitigated by techniques such as selecting material colors that would blend into the surroundings, aligning the new towers with the existing towers, and maintaining a screen of natural vegetation in the corridor on each side of major highways and rivers. Based on the design and vegetation control practices, the visual impacts to members of the public from the NAPS transmission lines will be SMALL.

5.6.3.5 **Conclusions**

Potential impacts from electric shock, EMF exposure, noise, or visual impacts from transmission system operations will be SMALL, and no mitigation measures or controls are warranted.

Section 5.6 References

1. National Research Council, "Possible Health Effects of Exposure to Residential Electric and Magnetic Fields," October 1996.

2. National Institute of Environmental Health Sciences/National Institutes of Health, "EMF, Electric and Magnetic Fields Associated with the Use of Electric Power, Questions and Answers," June 2002.

3. NIEHS report to U.S. Congress, "Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields," June 1999.

4. National Institute of Environmental Health Sciences/National Institutes of Health, "NIEHS Report on Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields," May 1999.

5. World Health Organization, "Electromagnetic Fields and Public Health - Electromagnetic Hypersensitivity - Fact Sheet No. 296," December 2005.

5.7 Uranium Fuel Cycle Impacts

The information for this section is provided in ESP-ER Section 5.7, and associated impacts for light-water reactors are resolved as SMALL in FEIS Section 6.1.

No new and significant information has been identified for this section.

5.8 Socioeconomic Impacts

The information for this section is provided in ESP-ER Section 5.8 and associated impacts are resolved in FEIS Sections 5.4, 5.5, and 5.7. These FEIS sections resolved that adverse impacts range from SMALL to MODERATE and beneficial impacts range from SMALL to LARGE. Supplemental information is provided below.

In addition, supplemental information on recreational impacts is provided in Section 5.10.1.6 that addresses specifically the lake mitigating actions resulting from the IFIM study.

In ESP-ER Section 5.8, commitments were made to perform a confirmatory noise evaluation and a visual impact study.

Cooling Tower Noise Study

For the ESP-ER, a noise study was performed for the main cooling tower and the service water cooling tower, and the results are documented in ESP-ER Section 5.8. To satisfy the commitment made in the ESP-ER, a confirmatory analysis of the noise level associated with the cooling towers was performed, using the location of the towers, the topography of the area surrounding the towers, and manufacturer's data typical of the towers selected for Unit 3. The methodology used was the same as that used in the ESP-ER analysis. The confirmatory analysis concluded that the noise level reported in the ESP-ER, associated with the cooling towers, was bounding.

The noise level will be ≤ 65 dBA at the EAB.

Visual Impact Study

The visual impact study has been performed. Figures 5.8-1, 5.8-2, and 5.8-3 provide artist renderings of Unit 3, including the main building group (Reactor Building, Turbine Building, etc.) and the cooling towers, as they would appear upon their completion. These renderings have been superimposed on photographs taken of existing Unit 1 and 2 facilities from various locations.

Figures 5.8-1 and 5.8-2 depict the approach to the main gate along the plant access road, in views progressively closer to the gate. The principal Unit 3 structures encountered along this approach are the hybrid and dry cooling towers, which emerge in profile off the road to the north. The low profile of the towers results in their view being mostly obscured behind a line of trees adjacent to the access road.

Figure 5.8-3 depicts the facility looking southwest from the Unit 1 and 2 intake area. From this perspective, the Unit 3 facilities are seen to blend in with the existing Units 1 and 2 buildings. The Unit 3 profile is of a similar shape and size as that of Units 1 and 2. The overall shape and configuration of the Unit 3 setting, which consists of a main building group with several adjacent smaller buildings, is similar to that of the existing units.

These figures portray the completed facility. During construction of Unit 3, there would be additional temporary visual impacts. Equipment and material storage areas, parking areas, and elevated cranes and other construction equipment would be visible at least in part as construction progresses. However, these impacts would be temporary and would not be unexpected by members of the public during construction of new Unit 3.

In summary, the visual impact to the public from Unit 3 will be similar to the visual impact from the existing units, and thus the aesthetic impact will continue to be SMALL. No mitigation measures or controls are warranted.

Figure 5.8-1 Looking Northeast Along the Plant Access Road

Figure 5.8-2 Looking Northward from Final Approach after Main Gate. Unit 3 Is Shown in the Distance.

Figure 5.8-3 Looking Southwest from Unit 1 and 2 Intake Area

5.9 Decommissioning

FEIS Sections 6.3 and 7.9 identified that impacts from decommissioning were not addressed at the ESP-ER stage and would be required to be addressed at the COL stage. The following information is provided to address the impacts from decommissioning.

5.9.1 Financial Assurance

Information on decommissioning funding, including the funding amount required by 10 CFR 50.75(c), method of funding, and certification, is provided in the Decommissioning Funding Assurance Report provided in COLA Part 1.

5.9.2 Environmental Impacts

According to NUREG-1555, Section 5.9 (Reference 1, p. 5.9-7), studies of social and environmental effects of decommissioning large commercial power generating units have not identified any significant impacts beyond those considered in the Final Generic Environmental Impact Statement (GEIS) on decommissioning (Reference 2). The GEIS evaluates the environmental impact of the following three decommissioning methods:

- DECON - The equipment, structures, and portions of the facility and site that contain radioactive contaminants are removed or decontaminated to a level that permits termination of the license shortly after cessation of operations.
- SAFSTOR - The facility is placed in a safe stable condition and maintained in that state until it is subsequently decontaminated and dismantled to levels that permit license termination. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the quantity of contaminated and radioactive material that must be disposed of during the decontamination and dismantlement.
- ENTOMB - This alternative involves encasing radioactive structures, systems, and components in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.

NRC regulations do not require a COL applicant to select one of these decommissioning alternatives or to prepare definite plans for decommissioning at the time of the COL (Reference 1, p. 5.9-6). Pursuant to 10 CFR 50.82, planned decommissioning activities would be described after a decision has been made by the licensee to cease operations. Further, the choice of decommissioning methods, the identification of disposal sites for waste, and other pertinent information required to develop definitive plans would be determined by the conditions at the time.

Therefore, at this stage, a general assessment of decommissioning environmental impacts is provided.

Decommissioning of a nuclear facility that has reached the end of its useful life is in essence an environmental remediation and therefore has an overall positive environmental impact (Reference 1, p. 5.9-7). The main adverse environmental impact, regardless of the specific decommissioning option selected, is the commitment of relatively small amounts of land for waste burial in exchange for the potential re-use of the land where the facility is located (Reference 2).

NUREG-0586 (Reference 2) indicates that the NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts presented in this report include: 1) occupational and population doses; 2) impacts of waste management; 3) impacts to air and water quality; and 4) ecological, economic, and socioeconomic impacts. NRC also indicated (Reference 3, p. 4-15) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. As such, Dominion adopts by reference the NRC conclusions regarding environmental impacts of decommissioning presented in NUREG-0586.

In addition, a DOE study (Reference 4, p. 17) indicated that projected physical plant inventories associated with the ESBWR design would generally be less than those for currently operating power reactors. This is due to the advances in technology and the use of passive support systems that have significantly simplified and reduced inventories of electrical cabling, piping, pumps, motors, instrumentation and controls wiring, building size and concrete volume typically used in contemporary power plants. This ultimately reduces the overall quantity of contaminated and non-contaminated waste required for disposal, along with transportation to and from disposal sites. Additionally, the ESBWR is designed to reduce accumulation of radioactivity in plant components (DCD Section 12.1.2). An ESBWR has only one significant source of radiation in the containment post operation—the reactor core (DCD Section 12.2.1.1). It also includes a number of design features as described in DCD Section 12.1.2 to maintain low occupational doses during decommissioning. Further, the new facility is situated on the existing NAPS site and is contained within the original site boundaries, not requiring encroachment onto additional property that is not already designated for use in power production. Therefore, the estimated environmental impacts of decommissioning presented in NUREG-0586 are reasonably expected to bound the impacts of decommissioning an ESBWR at North Anna.

Regardless of the option chosen in the future, decommissioning must be completed within 60 years of permanent cessation of plant operations per 10 CFR 50.82(a)(3). Unit 3 would be operated until the approved combined license expires and then decommissioning activities would be initiated in accordance with NRC requirements. In accordance with 10 CFR 50.82, these decommissioning activities would include the following submissions:

1. Written certification to the NRC within 30 days of the decision to permanently cease operations per 10 CFR 50.4(b)(8);

2. Written certification to the NRC once the fuel has been permanently removed from the reactor vessel per 10 CFR 50.4(b)(9);

3. A post-shutdown decommissioning activities report (PSDAR) to the NRC within two years after permanent cessation of operations per 10 CFR 50.82(a)(4), detailing planned decommissioning activities, schedule for the accomplishment of significant milestones, estimated decommissioning costs, and documentation showing that the environmental impacts associated with the site-specific decommissioning activities are bounded by appropriate previously issued environmental impact statements and;

4. A license termination plan at least two years before termination of the license date, per 10 CFR 50.82(a)(9), which includes: site characterization, identification of remaining dismantlement activities, plans for site remediation, detailed plans for the final radiation survey, a description of the end use of the site (if restricted), an updated site-specific estimate of remaining decommissioning costs and a supplement to the environmental report describing any new information or significant environmental change associated with the proposed termination activities.

During decommissioning of Unit 3 facilities, radiological doses would be controlled with appropriate work procedures, shielding, and other control measures similar to those used during plant operations. Experience with decommissioned power plants has shown that the occupational exposures during the decommissioning period are comparable to those associated with refueling and plant maintenance of an operational unit (Reference 2). Each decommissioning alternative has radiological impacts resulting from the transport of materials to disposal sites. The expected impact from this transportation activity would not be significantly different from that associated with normal operations (Reference 1, Section 5.9).

Based on the factors described above, it can be reasonably concluded that the environmental impacts resulting from decommissioning proposed Unit 3, after it ceases operations, are bounded by those presented in NUREG-0586. Pursuant to 10 CFR 50.82(a)(4), a further analysis would be provided at the time of decommissioning, when the activities and schedule are known, to demonstrate that the previously estimated impacts are still bounding.

Section 5.9 References

1. U.S. Nuclear Regulatory Commission, "Environmental Standard Review Plan," NUREG-1555, October 1999.

2. U.S. Nuclear Regulatory Commission, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," NUREG-0586, Supplement 1, November 2002.

3. U.S. Nuclear Regulatory Commission, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," NUREG-0586, August 1988.

4. U.S. Department of Energy, "Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs," Volume 1, May 27, 2004.

5.10 Measures and Controls to Limit Adverse Impacts During Operation

Measures and controls to limit adverse impacts during operation were addressed in ESP-ER Section 5.10 and in FEIS Section 5.11. Those measures and controls remain applicable to Unit 3, along with the following new mitigation measures and controls:

- Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be controlled by the limits established in VPDES permit (Sections 5.2.2 and 5.5.1).
- The new and separate Unit 3 sanitary waste treatment systems would be governed by applicable regulations and permits (Section 5.5.1).
- Operation of a dechlorination system would neutralize chlorine in the circulating water and plant service water cooling system blowdown before discharge to the WHTF and eventually to the North Anna Reservoir (Section 5.2.2).
- Increase the normal pool level of Lake Anna (North Anna Reservoir) by 3 inches from Elevation 250.0 ft msl to 250.25 ft msl to reduce the potential frequency of occurrence and duration of low flow conditions, and to reduce impacts on the ecology, wetlands, and recreation in Lake Anna and downstream (Section 5.10.1).
- Continue collaboration with Virginia resource agencies to address long-term enhancements within the watershed (Section 5.10.1).

5.10.1 Mitigating Actions Based on the Results of the IFIM Study

5.10.1.1 IFIM Study

The final IFIM study report was submitted to VDEQ in October 2009. The scope of the IFIM study was developed in consultation with the VDEQ, VDGIF, and VDCR. The agency-approved "North Anna IFIM Study Plan" (March 28, 2007) included components that evaluated how the addition of a third unit could impact habitat for fish, other organisms, and recreation on the North Anna River and Pamunkey River. Wetlands, boat docks, and ramps on Lake Anna were also studied to assess a potential rise in lake level. Completion of the IFIM study satisfies the special condition in the Coastal Zone Consistency determination for North Anna Power Station Unit 3 and ESP Permit Condition 3.I.(2) (issued November 27, 2007). Dominion will continue collaboration with Virginia resource agencies to address other longer-term enhancements within the watershed.

Two primary concerns to natural resource agencies and other stakeholders were the potential for a higher frequency of reduced flows to the North Anna River and lake level changes. Specific objectives included avoiding significant increases in the frequency of low flow conditions, and avoiding impacts to downstream habitats for fish and other organisms. The frequency of 20 cubic feet per second (cfs) flow from the dam, which represents the required minimum flow from the dam under drought conditions (lake elevation <248.0 ft msl), was of interest because of potential impacts to aquatic habitats and downstream users of the rivers. Based on iterative interactions with the natural resources agencies, emphasis was placed on evaluating the frequency of various flows under three station operating scenarios:

- Existing Conditions – the current operation of Units 1 and 2, and associated lake management operations
- Lake Anna at 250.0 ft msl with Unit 3 Scenario – Dominion's proposed operations with three units and a year-round normal pool elevation of 250.0 ft msl. The cooling system would be operated in MWC mode below a lake elevation of 250.0 ft msl.
- Lake Anna at 250.25 ft msl with Unit 3 Scenario – An alternative operating scenario with three units and a year-round normal pool elevation of 250.25 ft msl. The cooling system would be operated in MWC mode below a lake elevation of 250.0 ft msl.

The study area comprised approximately 70 miles of stream between the North Anna Dam and the head of tide in the Pamunkey River at the U.S. Route 360 bridge. Fifteen individual and groups of fish and invertebrates were identified for evaluation. Each of these has specific habitat requirements for living and reproducing (e.g., water velocity, water depth, bottom material). The study also examined how changes in flow from the North Anna Dam could affect recreation.

In summary, based on the results of the IFIM study, Dominion plans to: 1) increase the normal pool level of Lake Anna by 3 inches to Elevation 250.25 ft msl year-round, once Unit 3 is operational; 2) provide recreational flows to North Anna River each Saturday during June and July, when lake elevations exceed 250.0 ft msl, once Unit 3 is operational; and 3) develop a memorandum of agreement with VDGIF to provide additional enhancement to watershed aquatic habitat.

5.10.1.2 **Lake Operation Changes with 250.25 ft msl Normal Pool Level**

As a result of conducting the IFIM study, and once Unit 3 begins operation, the normal pool level will be raised to Elevation 250.25 ft msl in Lake Anna (North Anna Reservoir) year-round (i.e., a

3-inch rise above the existing normal pool level). Minimum flow releases from the North Anna Dam are regulated by the Commonwealth of Virginia under the VPDES Permit. The Lake Level Contingency Plan as stipulated in the current VPDES permit for NAPS (Reference) requires a minimum instantaneous discharge of 40 cfs from the Lake Anna impoundment, except under drought conditions. During droughts when lake level falls below Elevation 248 ft msl, releases can be incrementally reduced to a 20 cfs minimum. These minimum release rules of 40 cfs and 20 cfs are expected to remain the same when the normal pool level of Elevation 250.25 ft msl becomes effective.

5.10.1.3 Hydrologic Alterations and Water-Use Impacts with 250.25 ft msl Normal Pool Level

5.10.1.3.1 Hydrologic Alterations

Under this mitigating action, even though the normal pool level of the reservoir would be raised 3 inches, the operating schedule of Unit 3 circulating water (CIRC) system cooling towers in EC mode versus MWC mode relative to lake levels would be the same as described in ESP-ER Section 3.4. Table 5.10-1 summarizes specifically how Dominion plans to operate the CIRC cooling tower system and manage the dam releases at different lake levels.

The design of the Unit 3 station water intake system and blowdown discharge system would accommodate a 3-inch rise in the normal pool level. The water level in the WHTF is designed to operate with a differential head of 1 to 1.5 feet normally above the water level in the reservoir. At the normal pool level of Elevation 250.25 ft msl, the normal water level in the discharge canal would be about Elevation 251.75 ft msl.] The schematic section views of the intake structure and the discharge system at the normal pool level of Elevation 250.25 ft msl are shown on Figures 5.10-1 to 5.10-3. There would be no change to the minimum operating water level of Elevation 242 ft msl for the existing units and Unit 3 with this lake mitigating action.

The new normal pool level of Elevation 250.25 ft msl will introduce small changes to the physical attributes and hydrologic characteristics of the lake as described below. In terms of hydrologic impacts as a result of the operation of Unit 3, the change would also be SMALL.

The surface area of the lake increases with higher water levels, but the impacts with the increase due to a 3-inch rise in the pool level will be SMALL. For the purposes of hydrologic alteration and water-use impacts evaluations, the nominal surface area of the lake is considered to remain on the same order of 13,000 acres; with 9600 acres in the North Anna Reservoir, and 3400 acres in the WHTF.

At the Elevation 250.25 ft msl normal pool level, the lake storage will increase to 308,300 acre-ft, an increase of 3 inches or about 3300 acre-ft, which is approximately one percent additional volume over the 305,000 acre-ft storage at 250 ft msl pool level. The 3300 acre-ft increase in storage volume will be part of the conservation and active storage, and will be accompanied by a corresponding reduction of 3 inches in the flood control storage, which will be lowered from the current 15 feet to 14.75 feet above normal pool level, as shown in Table 5.10-2.

In addition to the surface area of the lake, other nominal attributes, such as the length of the lake, the shoreline length, and the maximum water depths in the North Anna Reservoir and the WHTF, are also expected to increase only marginally, and therefore are considered to remain essentially the same as in the existing lake operation with the pool level at Elevation 250 ft msl. The changes in the major physical attributes of the North Anna Reservoir and WHTF with the 3-inch rise in normal pool level are further summarized in Table 5.10-3.

The 3-inch change in the normal pool level and the corresponding change in the storage volume as a result of this mitigating action are relatively small, on the order of one percent. The physical hydrologic and hydrodynamic properties of the lake, including the lake current circulation patterns and magnitudes, scouring and erosion potentials, turbidity levels, sediment transport and siltation behavior, stratification patterns, and the associated impacts from the operation of Unit 3 are expected to be essentially the same as described in ESP-ER Section 5.3.1.1. Consequently, this mitigation would not change the FEIS conclusions that the stratification pattern in Lake Anna would not change with the operation of Unit 3 (FEIS Sections 5.4.2.4 and 5.4.2.5), and that because low-flow velocities in Lake Anna predominate, increased shoreline erosion, lake-bed scouring and increased turbidity levels caused by the operation of Unit 3 would not be detectable or destabilizing to aquatic resources of Lake Anna (FEIS Section 5.4.2.7). Although the flood control volume will be lowered by about one percent, an analysis of extreme floods, such as the probable maximum flood event, indicates that there would be no measurable increase in the flood level at Lake Anna. Hydrologic impacts related to plant water use, flow releases from the dam and frequency of low flow conditions in the lake and the North Anna River are described in Section 5.10.1.3.2.

5.10.1.3.2 **Water Use Impacts**

As part of the IFIM study, the impacts of plant water use on lake levels and on flow releases from the North Anna Dam, especially during drought conditions, were evaluated with a water budget model that incorporated a normal pool level of Elevation 250.25 ft msl when Unit 3 commences operation. The model approach and formulation are the same as the Lake Anna water budget model described in ESP-ER Section 5.2.2, with the following exceptions:

- The lake operation rule curve implemented the normal pool level of Elevation 250.25 ft msl such that when lake level is less than or equal to Elevation 250.25 ft msl, a minimum instantaneous flow of 40 cfs would be released from the dam. When lake level drops to or below Elevation 248 ft msl, releases would be reduced to 20 cfs minimum. For lake level greater than or equal to Elevation 250.35 ft msl (0.1 ft was added to the normal pool level in the model to approximate the potential head buildup behind the dam), any inflow in excess of the evaporative losses would be released, provided that the minimum release requirements are met.
- At the recommendation of the state agencies, the model simulation was extended four and one half years for the time period from October 1978 through October 2007 to capture the influence of climatic conditions of recent years.
- The evaporation losses from the CIRC cooling towers of Unit 3 were estimated based on revised performance characteristics from technology inputs.
- The Unit 3 CIRC cooling towers would operate in the same manner as described in ESP-ER Section 5.2.2, except that the dry tower implemented in the model could dissipate the entire heat load when the dry bulb temperature is equal to or less than 40°F, lower than the 67°F used in the ESP model.

The remaining model input data including total heat loads and station capacity factors (or availability factors) of the existing units and Unit 3, the circulating water flow rates of the existing units, the elevation-storage relationship of Lake Anna, and the EC mode versus MWC mode operation rule of Unit 3 in response to water levels are the same as those used in the ESP model. Simulations were conducted on a weekly basis to predict lake levels and flow releases at the North Anna Dam for the 29-year period extending from October 1978 through October 2007, a total of 1517 weeks. Table 5.10-4 summarizes the results of the predicted downstream flow releases. For comparison purposes, water budget simulations were also performed for two additional scenarios:

- The existing condition with Lake Anna at Elevation 250 ft msl pool level and only Units 1 and 2 in operation.
- Lake Anna at Elevation 250 ft msl pool level with both the existing units and Unit 3 in operation.

Table 5.10-4 indicates that, for existing conditions over many years, water would be released from the dam at a rate of 20 cfs 4.7 percent of the time. If the pool level remained at Elevation 250.0 ft msl, this frequency would increase to 6.5 percent of the time due to increased plant water needs associated with Unit 3 operation. At the new normal pool level of Elevation 250.25 ft msl, the frequency of releases at 20 cfs with Unit 3 in operation would be 5.7 percent of the time, closer to the existing condition. Thus, raising the pool level in Lake Anna by 3 inches would meet the objective of this mitigating action by minimizing the disruption to flows in the North Anna River during drought conditions.

Table 5.10-5 provides the water level frequency for the low water levels of interest to Lake Anna users and the minimum water level for the 29-year simulation period. With the pool level raised by 3 inches to Elevation 250.25 ft msl, and Unit 3 operating, the percent of time the lake level would lower to Elevation 248 ft msl or less is 5.5 percent, versus 6.3 percent if the pool level remained at Elevation 250.0 ft msl. The flow discharges reported in Table 5.10-4 were determined by the computed lake level at the beginning of each model time step. The lake levels shown in Table 5.10-5 correspond to the levels at the end of each time step. Even with this slight model difference, results are similar.

Figure 5.10-4 shows the variation in the lake levels as a function of time as predicted by the water budget model for the existing condition and for the Elevation 250.25 ft msl raised pool level mitigating action scenario for Unit 3. It is evident from both Table 5.10-5 and Figure 5.10-4 that the proposed lake mitigating action of raising the pool level to Elevation 250.25 ft msl will help reduce the impact of additional plant water needs for Unit 3, both in maintaining a slightly higher minimum lake water level and in reducing the frequency of low lake levels. Based on these low outflow and low lake level frequencies, it is concluded that the impacts associated with Unit 3 operation on the downstream flow and lake level is SMALL, less than 2 percent when compared with existing conditions. Impacts would be further reduced to about 1 percent or less with implementation of the IFIM lake mitigating action of raising the normal pool level by 3 inches.

Table 5.10-6 compares the available water supplies to the plant water needs for the existing units and Unit 3 on a long-term time-averaged basis, with and without the mitigating action of raising the normal pool level of the lake by 3 inches, as estimated using the extended water budget model. It demonstrates that the net inflow to Lake Anna exceeds the water use expected from the operation of the existing units and Unit 3 for both scenarios. The long-term average outflow from Lake Anna to the North Anna River downstream was estimated to be about 278 cfs for the existing conditions with only Units 1 and 2 in operation.

The long-term average evaporation loss associated with Unit 3 operation is estimated to be about 20 cfs with the normal pool level maintained at Elevation 250 ft msl, and about 22 cfs with the pool level raised to Elevation 250.25 ft msl.

The long-term average outflow is reduced by the Unit 3 evaporation loss rates of 20 cfs to about 258 cfs, at the normal pool level of 250 ft msl. At the new normal pool level of 250.25 ft msl, the long-term average outflow is reduced by the Unit 3 evaporation loss of 22 cfs to about 256 cfs.

This lake mitigation action does not affect the EC mode and MWC mode maximum evaporation rates, maximum blowdown rates and maximum make-up water rates for Unit 3 cooling towers as shown in Table 3.0-2.

5.10.1.4 Aquatic Ecology Impact with Elevation 250.25 ft msl Normal Pool Level

The impact of the 3-inch lake level increase on the aquatic ecology in Lake Anna is expected to be SMALL. The frequency of drought releases of 20 cfs will be reduced, which reduces impact to aquatic habitat.

5.10.1.5 Wetland Impacts with Elevation 250.25 ft msl Normal Pool Level

The primary purpose of the lake studies (field and desktop) was to evaluate the relationship between Lake Anna water levels and wetland areas. Field studies were conducted within five coves on Lake Anna in September 2007. The selected coves were associated with the confluence of tributaries entering Lake Anna, and were located at the interface between tributary streams and the existing Elevation 250.0 ft msl normal pool level.

To define the evaluation areas the study utilized existing aerial photography from the Virginia Geographic Information Network, national wetlands inventory (NWI) maps, topographic data and Light Detection and Ranging (LIDAR) information collected in 2006. The GIS desktop analysis of wetlands around Lake Anna and its associated environs was conducted in 2008.

Forested wetlands, primarily located at higher elevations and away from the lake/tributaries, are not likely to experience any change from the 3-inch increase in normal pool level. Emergent wetlands located near the elevation of the current pool level should not change substantially in existing distribution and areal coverage relative to existing conditions. Any wetland losses due to more frequent inundation resulting from the 3-inch level increase are expected to be SMALL, and would likely be offset by new emergent wetlands which will grow over time at a slightly higher elevation.

In addition, Lake Anna and WHTF wetland impacts associated with the 3-inch increase in normal pool level have been discussed with USACE and VDEQ representatives. A USACE jurisdictional determination has been received, and future potential wetland impacts will be addressed through an individual state water protection permit.

5.10.1.6 Recreational Impacts with 250.25 ft msl Normal Pool Level

The proposed increase of the normal pool level of Lake Anna would have multiple positive recreational implications. Canoeists would have enhanced conditions in both the Fall and Piedmont zones of the North Anna River caused by potential increases in recreational water releases. In June and/or July additional releases would occur one day each weekend when the water elevation in Lake Anna exceeds 250.0 ft msl.

As part of the IFIM study, fifteen boat docks and six marinas in Lake Anna were evaluated for the ability of recreational boaters to get into and out of their boats safely with a 3-inch increase in normal pool level. Lake Anna would experience a slight increase in lake elevation under the 250.25 ft scenario approximately 75 percent of the time. This benefit would be particularly noticeable during drought conditions when the pool level may be only 1.7 inches lower than existing conditions compared to an estimated 4.2 inches below existing conditions for three units operating at the 250.0 ft msl normal lake level. Therefore, the operation of Unit 3 with the 3-inch increase in normal pool level would not adversely affect access to boats from public docks on Lake Anna.

Section 5.10 Reference

Commonwealth of Virginia, Department of Environmental Quality, "VPDES Permit No. VA0052451, Authorization to Discharge under the Virginia Pollutant Discharge Elimination System and the Virginia State Water Control Act," October 25, 2007.

Table 5.10-1 Dam Releases and Modes of Operation of Unit 3 CIRC Cooling Towers Relative to Lake Levels

Lake Level (ft msl)	Dam Release Flow	EC/MWC Mode
≥250.25	≥40 cfs[a]	EC
≥250.0 to <250.25	40 cfs[a]	EC
>248.0 to <250.0	40 cfs	MWC[b,c]
≤ 248.0	20 cfs	MWC[c]

a. Provide weekend recreational flows during June and July when lake level is >250.0 ft msl.
b. Allow up to seven consecutive days when the lake level is <250.0 ft msl each time the dry tower is placed in service.
c. Annual allowance when lake level is <250.0 ft msl to operate in EC mode only (dry tower fans off) for up to 100 hours/year to meet high electricity demand.

Table 5.10-2 Lake Anna Storage Allocation Based on the 250.25 ft msl Normal Pool Level

Purpose	Volume (acre-feet)
Minimum recreational pool and inactive storage below 246 ft msl	255,000
Conservation and active storage, 246 to 250.25 ft msl	53,300
Flood control storage, 250.25 to 265 ft msl	241,700
Total Storage	550,000

Table 5.10-3 Physical Attributes of Lake Anna

North Anna Reservoir		
Normal Pool Level	250 ft msl	250.25 ft msl
Surface Area	9600 acres	9600 acres
Downstream from NAPS[a]	4998 acres	4998 acres
Upstream from NAPS	4602 acres	4602 acres
Volume	10.6×10^9 ft^3	10.7×10^9 ft^3 [b]
Mean Depth	25.35 ft [c]	25.6 ft
Downstream from NAPS	36 ft	36.25 ft
Upstream from NAPS	13 ft	13.25 ft
Maximum Depth	80 ft	80 ft
Length	17 miles	17 miles
Shoreline Length	272 miles	272 miles
Waste Heat Treatment Facility		
Normal Water Level	251.5 ft msl	251.75 ft msl
Surface Area	3400 acres	3400 acres
Volume	2.66×10^9 ft^3	2.7×10^9 ft^3 [b]
Mean Depth	18 ft [c]	18.25 ft
Maximum Depth	50 ft	50 ft
Side-Arm Area	1530 acres	1530 acres

a. From NAPS to the North Anna Dam.
b. Storage Volume at Elevation 250.25 ft msl is estimated based on "Mean Depth" x "Surface Area."
c. Mean Depth at Elevation 250 ft msl is defined as "Volume" divided by "Surface Area."

Table 5.10-4 Lake Anna Low Outflow Frequency

	Percent of Time Outflow is Less Than or Equal to Indicated Values		
Outflow (ft^3/s)	**Existing Units (250 ft msl Pool Level)**	**Existing Units plus Unit 3 (250 ft msl Pool Level)**	**Existing Units plus Unit 3 (250.25 ft msl Pool Level)**
100	48.6%	54.1%	54.6%
80	46.1%	51.6%	52.1%
60	44.2%	49.0%	49.8%
40	42.2%	47.6%	48.5%
20	4.7%	6.5%	5.7%

Table 5.10-5 Lake Anna Low Water Level Frequency

	Percent of Time Lake Level is Less Than or Equal to Indicated Values		
Elevation (ft msl)	**Existing Units (250 ft msl Pool Level)**	**Existing Units plus Unit 3 (250 ft msl Pool Level)**	**Existing Units plus Unit 3 (250.25 ft msl Pool Level)**
248	4.7%	6.3%	5.5%
246	0.9%	1.2%	1.1%
244	0%	0%	0%
242	0%	0%	0%
Minimum Lake Water Level	245.1 ft msl	244.2 ft msl	244.4 ft msl

Table 5.10-6 Available Water Supply Versus Plant Water Needs With and Without Lake Mitigating Actions

Quantity	Flow Rate (ft^3/s) Existing Units plus Unit 3 (El. 250 ft msl Pool Level)	Existing Units plus Unit 3 (El. 250.25 ft msl Pool Level)
Net Inflow[a]	369	369
Pre-Operational Evaporation[b]	92	92
Minimum Release[c]	40	40
Available Water Supply[d]	237	237
Plant Water Needs[e]	20	22[f]

a. Average net inflow estimated from the extended water budget model.

b. Natural evaporation from the lake plus forced evaporation from the existing units on a time-averaged basis and based on a 93% plant capacity factor.

c. Minimum release for Lake Anna water levels in excess of Elevation 248 ft msl.

d. Available water supply is defined as (Net Inflow – Pre-operational Evaporation – Minimum Release).

e. Average evaporation associated with Unit 3 wet cooling towers based on a 96% plant capacity factor, predicted by the extended water budget model.

f. The value of 22 cfs was rounded from 21.6 cfs.

Figure 5.10-1 Schematic View of Station Water Intake

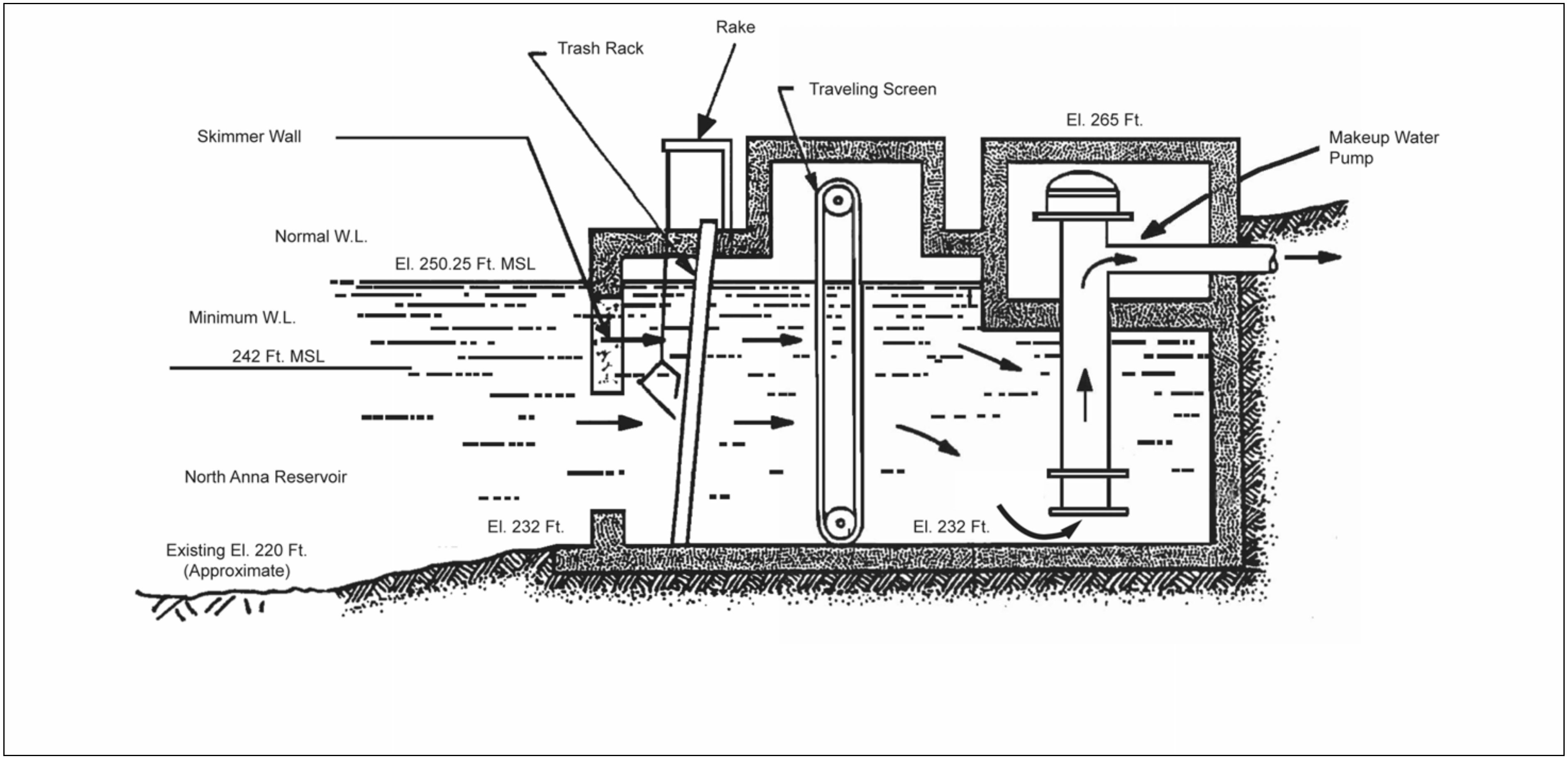


Figure 5.10-2 Discharge Channel and Dike 3 Outlet Structure

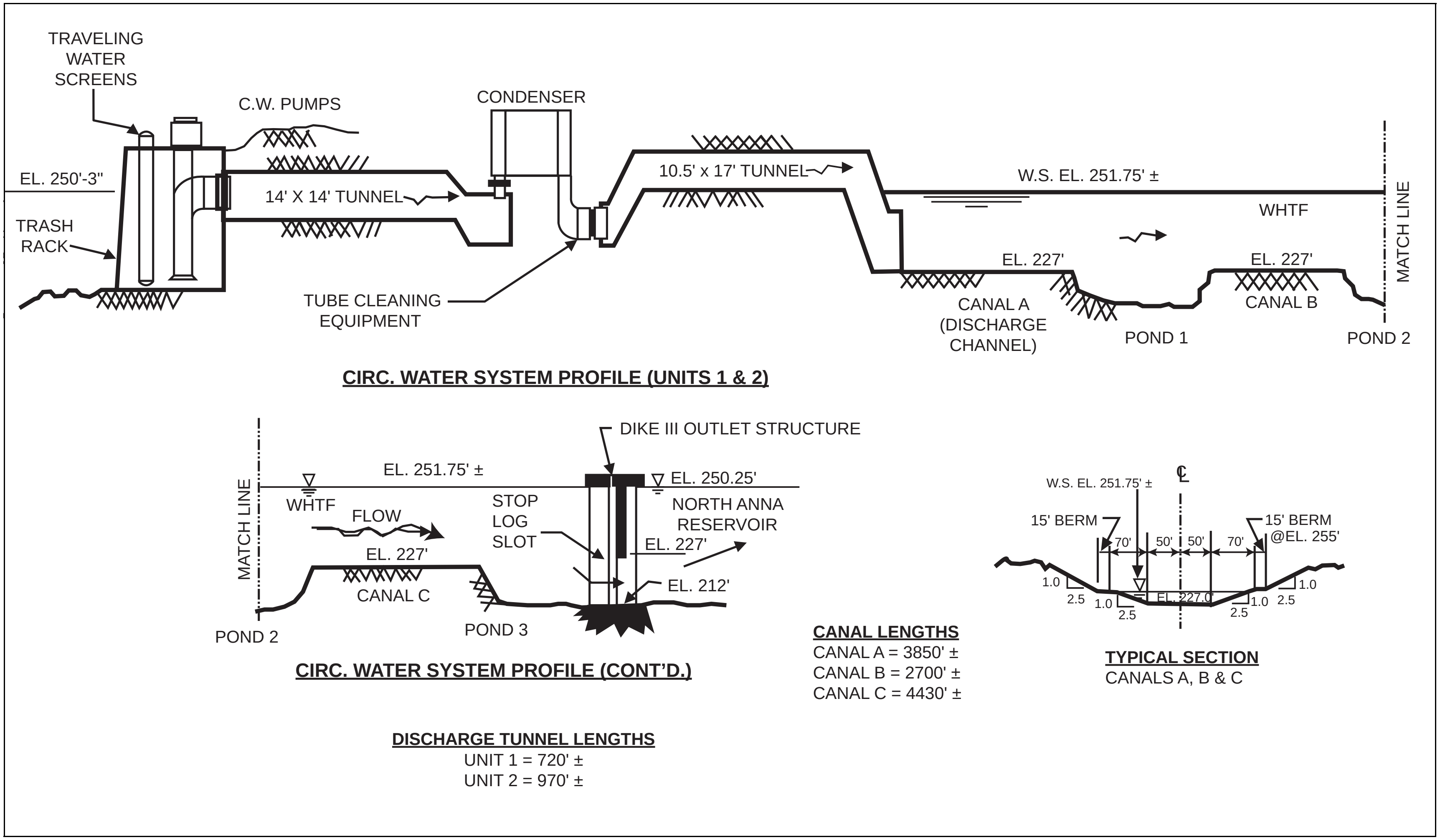


Figure 5.10-3 Schematic Diagram of the Discharge System

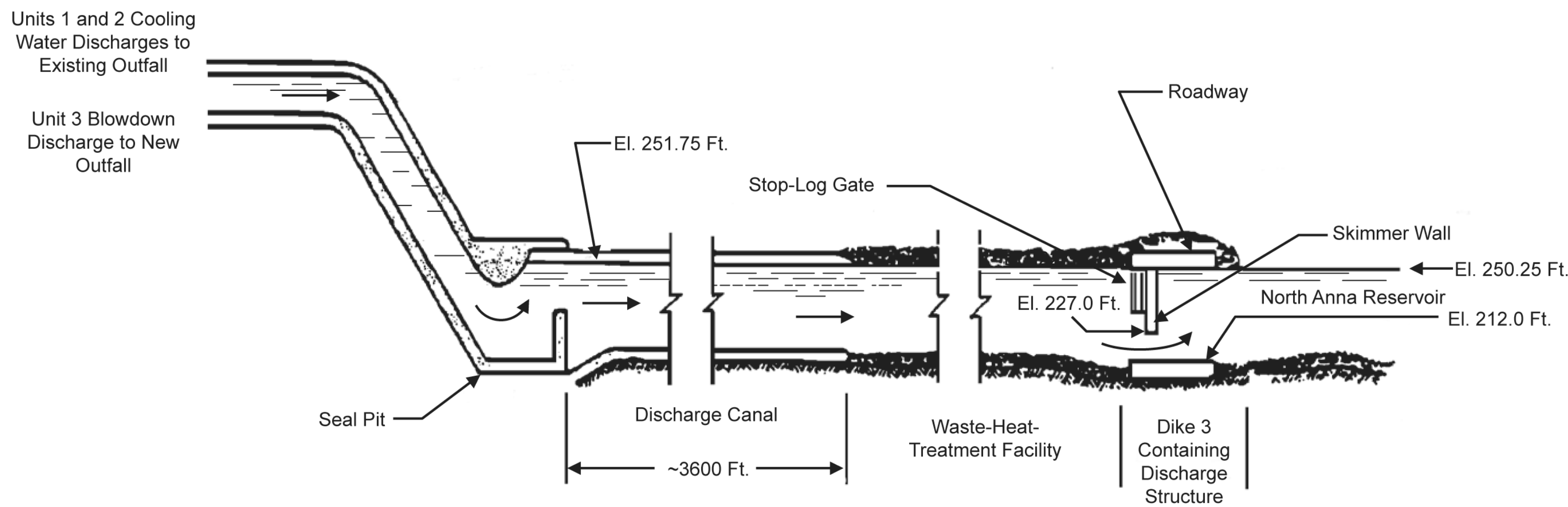


Figure 5.10-4 Lake Anna Water Level Hydrographs (October 1978 to October 2007)

Chapter 6 Environmental Measurements and Monitoring Programs

6.1 Thermal Monitoring

The information for this section is provided in ESP-ER Section 6.1 and resolved in FEIS Section 2.6.3.3.

No new and significant information has been identified for this section.

6.2 Radiological Monitoring

The information for this section is provided in ESP-ER Section 6.2 and resolved in FEIS Section 5.9.6.

No new and significant information has been identified for this section.

6.3 Hydrological Monitoring

The information for this section is provided in ESP-ER Section 6.3 and resolved in FEIS Section 2.6.1.3.

No new and significant information has been identified for this section.

6.4 Meteorological Monitoring

The information for this section is provided in ESP-ER Section 6.4 and resolved in FEIS Section 2.3.1.6. Dominion will use the existing Unit 1 and 2 data recording systems for Unit 3. These systems will be linked to the Unit 3 control room for meteorological monitoring.

No new and significant information has been identified for this section.

6.5 Ecological Monitoring

The information for this section is provided in ESP-ER Section 6.5 and resolved in FEIS Section 2.7.

No new and significant information has been identified for this section.

6.6 Chemical Monitoring

The information for this section is provided in ESP-ER Section 6.6 and resolved in FEIS Section 2.6.3.4.

No new and significant information has been identified for this section.

6.7 Summary of Monitoring Programs

The information for this section is provided in ESP-ER Section 6.7. No new and significant information has been identified for this section.

Chapter 7 Environmental Impacts of Postulated Accidents Involving Radioactive Materials

7.1 Design Basis Accidents

The information for this section is provided in ESP-ER Section 7.1 and associated impacts are resolved as SMALL in FEIS Section 5.10, for light-water reactors. Supplemental information, regarding Unit 3 specific source terms and doses, is provided in the following sections.

7.1.1 Selection of Accidents

No new and significant information has been identified for this section. The same ESBWR accidents are considered as in ESP-ER Section 7.1. These encompass all of the Design Basis Accidents (DBAs) evaluated for radiological consequences in DCD Chapter 15.

7.1.2 Evaluation Methodology

No new and significant information has been identified for this section.

7.1.3 Source Terms

The activity releases and doses for Unit 3 are based on a power level of 4590 MWt, which represents a core thermal power of 4500 MWt multiplied by an uncertainty factor of 1.02. Unit 3 DBA source terms have been updated and are presented as isotopic activity releases to the environment in the unit of megabecquerel (MBq) in DCD Section 15.4, Tables 15.4-3a, 15.4-7, 15.4-12, 15.4-15, 15.4-18a, 15.4-18b, and 15.4-22. These tables reflect updated activity releases from those presented in the ESP-ER. The DCD updated activity releases do not include the 25 percent margin of uncertainty previously assumed in the ESP-ER analysis.

7.1.4 Radiological Consequences

In the ESP-ER, design basis accident doses for the ESBWR were calculated based on activity releases, χ/Q values, breathing rates, and dose conversion factors. In this ER, Unit 3-specific doses are calculated based on the DCD doses for the ESBWR. For each of the design basis accidents, the Unit 3-specific dose is calculated by multiplying the ESBWR dose (provided in DCD Section 15.4) by the ratio of the Unit 3 site-specific χ/Q value to the DCD χ/Q value (provided in DCD Section 15.4). The Unit 3 site-specific χ/Q values are the time-dependent χ/Q values from FEIS Table I-1. The resulting χ/Q ratios are shown in Table 7.1-1. Because the DCD does not provide time-dependent LPZ doses, the site LPZ dose is determined by multiplying the total DCD dose by the maximum χ/Q dose.

Because the Unit 3 site-specific χ/Q values are bounded by the DCD χ/Q values, the Unit 3-specific doses are within those calculated in DCD Section 15.4. The DBA doses summarized in Table 7.1-2 are based on individual accident doses presented in Table 7.1-3 through Table 7.1-10. These tables replace those showing ESBWR doses in the ESP-ER. For each accident, the EAB dose shown is for the two-hour period that yields the maximum dose, in accordance with RG 1.183 (Reference 1). The Unit 3-specific doses summarized in Table 7.1-2 are lower than and thus remain bounded by the surrogate ESBWR DBA doses calculated for the ESP-ER for all accidents except for Feedwater System Pipe Break with Equilibrium Iodine Activity (Table 7.1-3a, ESP-ER Table 7.1-6d), Failure of Small Line Carrying Primary Coolant Outside Containment with Equilibrium Iodine Activity (Table 7.1-4a, ESP-ER Table 7.1-13b), Main Steam Line Break with Equilibrium Iodine Activity (Table 7.1-6, ESP-ER Table 7.1-20c), and LOCA (Table 7.1-7, ESP-ER Table 7.1-24b). Furthermore, Feedwater System Pipe Break with Pre-Existing Iodine Spike (Table 7.1-3), Failure of Small Line Carrying Primary Coolant Outside Containment with Pre-Existing Iodine Spike (Table 7.1-4), and Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System Line Failure (with Pre-Existing Iodine Spike) (Table 7.1-9) were not considered in the ESP-ER. However, the Unit 3-specific doses for these accidents remain a small fraction of the regulatory limit. All doses are within the acceptance criteria of RG 1.183 and NUREG-0800 (Reference 2). Thus, the potential environmental impacts of DBAs will remain SMALL.

Section 7.1 References

1. U.S. Nuclear Regulatory Commission, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," Regulatory Guide 1.183, July 2000.

2. U.S. Nuclear Regulatory Commission, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," NUREG-0800, March 2007.

Table 7.1-1 DCD and Unit 3 Site-Specific χ/Qs, and Unit 3/DCD χ/Q Ratios

Accident	Location		χ/Q (sec/m^3) DCD	χ/Q (sec/m^3) Unit 3	Ratio (Unit 3/DCD)
Loss-of-Coolant Accident, Failure of Small Line Carrying Primary Coolant Outside Containment	EAB		2.00E-03	3.34E-05	1.67E-02
	LPZ	0–8 hr	1.90E-04	2.17E-06	1.14E-02
		8–24 hr	1.40E-04	1.50E-06	1.07E-02
		24–96 hr	7.50E-05	1.20E-06	1.60E-02
		96–720 hr	3.00E-05	9.00E-07	3.00E-02
All Others	EAB		2.00E-03	3.34E-05	1.67E-02
	LPZ		1.90E-04	2.17E-06	1.14E-02

Table 7.1-2 Summary of Design Basis Accident Doses

SRP Section	Accident	Unit 3 TEDE (Rem)		
		EAB	LPZ	Limit
15.2.8	Feedwater Line Break			
	Pre-Existing Iodine Spike	3.0E-01	1.9E-02	25
	Equilibrium Iodine Activity	1.8E-02	1.1E-03	2.5
15.3.3	Locked Rotor Accident	Not applicable to the ESBWR		
15.3.4	Reactor Coolant Pump Shaft Break	Not applicable to the ESBWR		
15.4.9	BWR Control Rod Drop Accident	Evaluation of radiological consequences not required		
15.6.2	Failure of Small Line Carrying Primary Coolant Outside Containment			
	Pre-Existing Iodine Spike	5.7E-03	1.1E-03	25
	Equilibrium Iodine Activity	1.7E-03	1.1E-03	2.5
15.6.4	Main Steam Line Break Accident			
	Pre-Existing Iodine Spike	4.3E-02	2.3E-03	25
	Equilibrium Iodine Activity	3.3E-03	1.1E-03	2.5
15.6.5	Loss-of-Coolant Accident	3.7E-01	6.2E-01	25
15.7.4	Fuel Handling Accident	6.9E-02	4.6E-03	6.3
	RWCU/SDC System Line Failure			
	Pre-Existing Iodine Spike	1.2E-01	8.0E-03	25
	Equilibrium Iodine Activity	6.7E-03	1.1E-03	2.5
15.7.5	Spent Fuel Cask Drop Accident	Evaluation of radiological consequences not required		

Table 7.1-3 Doses for ESBWR Feedwater Line Break, Pre-Existing Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	1.81E+01	1.67E-02	3.02E-01
LPZ	1.70E+00	1.14E-02	1.94E-02
Limit			25

Table 7.1-3a Doses for ESBWR Feedwater Line Break, Equilibrium Iodine Activity

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	1.10E+00	1.67E-02	1.84E-02
LPZ	1.00E-01	1.14E-02	1.14E-03
Limit			2.5

Table 7.1-4 Doses for ESBWR Failure of Small Line Carrying Primary Coolant Outside Containment, Pre-Existing Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	3.40E-01	1.67E-02	5.68E-03
LPZ	1.00E-01	1.14E-02	1.14E-03
Limit			25

Table 7.1-4a Doses for ESBWR Failure of Small Line Carrying Primary Coolant Outside Containment, Equilibrium Iodine Activity

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	1.00E-01	1.67E-02	1.67E-03
LPZ	1.00E-01	1.14E-02	1.14E-03
Limit			2.5

Table 7.1-5 Doses for ESBWR Main Steam Line Break, Pre-Existing Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	2.60E+00	1.67E-02	4.34E-02
LPZ	2.00E-01	1.14E-02	2.28E-03
Limit			25

Table 7.1-6 Doses for ESBWR Main Steam Line Break, Equilibrium Iodine Activity

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	2.00E-01	1.67E-02	3.34E-03
LPZ	1.00E-01	1.14E-02	1.14E-03
Limit			2.5

Table 7.1-7 Doses for ESBWR Loss-of-Coolant Accident

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	2.24E+01	1.67E-02	3.74E-01
LPZ	2.07E+01	3.00E-02	6.21E-01
Limit			25

Table 7.1-8 Doses for ESBWR Fuel Handling Accident

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	4.10E+00	1.67E-02	6.85E-02
LPZ	4.00E-01	1.14E-02	4.57E-03
Limit			6.3

Table 7.1-9 Doses for ESBWR RWCU/SDC System Line Failure, Pre-Existing Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	6.90E+00	1.67E-02	1.15E-01
LPZ	7.00E-01	1.14E-02	7.99E-03
Limit			25

Table 7.1-10 Doses for ESBWR RWCU/SDC System Line Failure, Equilibrium Iodine Activity

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	4.00E-01	1.67E-02	6.68E-03
LPZ	1.00E-01	1.14E-02	1.14E-03
Limit			2.5

7.2 Severe Accidents

The information for this section is provided in ESP-ER Section 7.2 and associated impacts are resolved as SMALL in FEIS Section 5.10.2 for light water reactors.

No new and significant information has been identified for this section.

7.3 Severe Accident Mitigation Alternatives

This section addresses severe accident mitigation alternatives (SAMAs), based on GEH's evaluation of severe accident mitigation design alternatives (SAMDAs) for the ESBWR (NEDO-33306, Reference 1), which is incorporated herein by reference, and North Anna site and regional data. This section demonstrates that the severe accident mitigation design alternatives screened out by GEH are also screened out when North Anna site-specific characteristics are considered.

In the GEH analysis, potential design improvements are identified, in a systematic method, and evaluated on a cost-benefit basis. The evaluation determined that there are no practical and cost-beneficial design enhancements that should be considered. Therefore, appropriate mitigating measures are already incorporated into the plant design.

This section determines that the conclusions in the GEH analysis remain valid for Unit 3. The analysis in this section indicates that there are no cost-beneficial design alternatives that would need to be implemented for Unit 3 to further mitigate severe accident risk.

7.3.1 **The SAMA Analysis Process**

Measures that could mitigate the consequences of a severe accident are known as SAMAs. The evaluation process for identifying potential SAMAs includes four steps:

1. Define the base case – The base case is the dose-risk and cost-risk of severe accident before implementation of any SAMAs. A plant's probabilistic risk assessment is a primary source of data in calculating the base case. The base case risks are converted to a monetary value to use for screening SAMAs.

2. Identify and screen potential SAMAs – Potential SAMAs can be identified from the plant's probabilistic risk assessment and the results of other plants' SAMA analyses. This list of potential SAMAs is assigned a conservatively low implementation cost based on historical costs, similar design changes and/or engineering judgment, then compared to the base case screening value. SAMAs with higher implementation cost than the base case are not evaluated further.

3. Determine the cost and net value of each SAMA – Each SAMA remaining after Step 2, has a detailed engineering cost evaluation developed using current plant engineering processes. If the SAMA continues to pass the screening value Step 4 is performed.

4. Determine the benefit associated with each screened SAMA – Each SAMA that passes the screening in Step 3, is evaluated using the probabilistic risk assessment model to determine the reduction in risk associated with implementation of the proposed SAMA. The reduction in risk benefit is then monetized and compared to the detailed cost estimate. Those SAMAs with reasonable cost-benefit ratios are considered for implementation.

The SAMA analysis for Unit 3 focuses on demonstrating that the North Anna site is bounded by the GEH DCD analysis and determining what magnitude of plant-specific design or procedural modifications would be cost-effective. The base case benefit value is calculated by assuming the current dose risk of the unit could be reduced to zero and assigning a defined dollar value for this change in risk. Any design or procedural change cost that exceeded the benefit value would not be considered cost-effective. The dose-risk and cost-risk results are monetized in accordance with methods established in NUREG/BR-0184, Regulatory Analysis Technical Evaluation Handbook, 1997. NUREG/BR-0184 presents methods for determination of the value of decreases in risk, using four types of attributes: public health, occupational health, offsite property, and onsite property. Any SAMAs in which the conservatively low implementation cost exceeds the base case monetization are screened out. If the analysis produces a value that is below that expected for implementation of any reasonable SAMA, no matter how inexpensive, then the remaining steps of the SAMA analysis are not necessary.

7.3.2 The GEH ESBWR SAMDA Analysis

NEDO-33306 compiles a list of potential SAMDAs based on a generic list from license renewal actions and the Advanced Boiling Water Reactor (ABWR) SAMA study. Most SAMDAs were then screened out based on their inapplicability to the ESBWR here or the fact that they were already included in the ESBWR design or accomplished by alternative features in the design. SAMDAs with rough implementation costs that far exceeded any reasonable benefit were also excluded. The maximum averted risk benefit presented in NEDO-33306 is $397,863. None of the SAMDAs passed the screening process.

GEH concluded that due to the low absolute value of core damage and offsite release risk, there are no design improvements that could yield a significant severe accident mitigation benefit, and it is unlikely that any future design changes could be justifiable.

7.3.3 Unit 3 ESBWR SAMA Analysis

Unit 3 specific design features (e.g., cooling towers, lake location, proximity to Units 1 and 2, weather, seismology) were all considered for potential impact on the generic GEH ESBWR SAMDA analysis, and none were determined to potentially impact it. To demonstrate the applicability of the GEH ESBWR SAMDA analysis to Unit 3, the MACCS2 Code was used to re-calculate offsite consequences for a severe accident of an ESBWR at the North Anna site. MACCS2 analysis used the source terms, release fractions, and core damage frequencies from the GEH ESBWR PRA with current site information (population, economic, and meteorological data). The offsite consequence results were then used to calculate the maximum averted risk benefit for Unit 3. The maximum averted risk benefit for Unit 3 is calculated to be $96,827 with a 7% discount rate applied, and $169,560 with a 3% discount rate applied. These maximum benefits are bounded by the generic value calculated in the GEH ESBWR SAMDA analysis.

New information pertinent to SAMDAs was addressed. The August 23, 2011 Mineral, Virginia earthquake was included in the analysis of probabilistic seismic hazard (FSAR 2.5). Also, seismic margins analysis of the ESBWR NEDO-33201 (Reference 2) concludes that the risks of beyond design basis earthquakes are sufficiently low. Seismic risk does not alter the SAMDA analysis as most SAMDAs have already been addressed in design, and implementation costs of others far exceed the averted risk benefit, therefore, no additional SAMDAs have been identified for this section.

A review was performed of the compilation of SAMAs in NEDO-33306 to identify procedural and administrative measures that were not considered design alternatives. Most of these items related to PWRs and have no relevance to the ESBWR. Those administrative and procedural measures applicable to the ESBWR will be considered for implementation when procedures are developed prior to fuel load.

Accordingly, no cost-beneficial SAMDAs have been identified. Further, pursuant to 10 CFR 51.30(d), the NRC will, as part of its design certification rulemaking, prepare an environmental assessment evaluating the costs and benefits of SAMDAs for the ESBWR. Pursuant to 10 CFR 51.50(c)(2) and 51.75(c)(2), this environmental assessment may be incorporated by reference into the ER and EIS upon completion.

Section 7.3 References

1. GEH Nuclear Energy, "ESBWR Severe Accident Mitigation Design Alternatives," Revision 4, NEDO-33306, October 2010.

2. GEH Nuclear Energy, "ESBWR Certification Probabilistic Risk Assessment," Revision 6, NEDO-33201, October 2010.

7.4 Transportation Accidents

The information for this section is provided in ESP-ER Section 3.8, and the associated impacts, with the exception of crud and activation products on spent fuel transportation accidents, are resolved as SMALL for light-water reactors in FEIS Section 6.2.

The evaluation of the impact of crud and activation products on spent fuel transportation accidents is provided in Section 3.8.

Chapter 8 Need for Power

This chapter demonstrates the need for the power to be generated by the proposed facility and related benefits. This demonstration is supported by an analysis, which is organized into five sections:

- A discussion of benefits in Section 8.0.1,
- A power system description in Section 8.1,
- An analysis of demand for capacity and energy in Section 8.2,
- An analysis of supply resources in Section 8.3, and
- An assessment of need in Section 8.4.

8.0.1 Benefits

This section describes the benefits associated with construction and operation of the proposed NAPS Unit 3. Non-monetary benefits of constructing and operating the proposed Unit 3 include benefits related to: net electrical generating benefits; fuel diversity; mitigated price volatility; enhanced reliability; emissions avoidance; waste reduction; and reduction in dependence on imported power. Monetary benefits of constructing and operating Unit 3 include benefits related to tax revenues and to the local and state economy.

8.0.1.1 Net Electrical Generating Benefits

As demonstrated in Section 8.4, the Dominion Zone, the region of interest (as defined in Section 8.1.1), has a specific need for new baseload capacity and this need is projected to increase. The baseload capacity supply portfolio in the Dominion Zone is currently out of balance with baseload requirements, because development of new baseload capacity has not kept pace with recent growth in capacity requirements. Instead, the growth in energy consumption has been met predominantly by the recent development of gas-fired units, which over the long term are more suitable as cycling or mid-range resources.

As shown in Section 8.4, there is a current need for baseload capacity in the Dominion Zone, and additional baseload capacity requirements in the Dominion Zone are projected to be approximately 2,100 MW and 2,800 MW by 2024 and 2028, respectively.[1] To meet its baseload requirements in 2012, DVP constructed the Virginia City Hybrid Energy Center (VCHEC), which is a 585 MW coal facility located in Virginia City, Virginia. DVP also completed uprates, from 2010 to 2013, totaling 126 MW to the existing North Anna and Surry power plants, 31 MW of uprates at Mt. Storm, and 16 MW at Chesterfield Power Station, but considerable additional baseload capacity will be needed. Currently, the VCHEC and Mt. Storm units have been providing needed baseload capacity and

1. If measured by the need to maintain peak summer margin, about 4,000 MW of capacity would be required by 2023, as discussed in Section 8.2.2.1.

energy to the Company's service territory, therefore they are considered part of the Dominion Zone supply portfolio.

The primary benefit of the proposed Unit 3 is the consistent provision of baseload capacity necessary to meet the needs of customers, and to maintain a reliable, stable supply of electricity within the Dominion Zone. The proposed Unit 3 will provide approximately 1,500 MW of average net summer capacity. Conservatively assuming an average capacity factor of 90 percent, the plant average annual electrical-energy generation is approximately 12,000,000 megawatt hours.[1] Unit 3 would provide a benefit to DVP's service territory by maintaining DVP's baseload capacity portfolio and helping to meet the growing baseload needs in the Dominion Zone. It is important for DVP to continue to maintain its diverse generation asset portfolio, both in terms of fuel diversity and operational diversity (baseload, intermediate and peaking) in order to protect against the risks of natural gas and oil price volatility, potential supply constraints, and potential future environmental regulations.

8.0.1.2 **Fuel Diversity Mitigated Price Volatility and Enhanced Reliability**

Energy diversity is a key to providing a reliable and affordable electrical power supply system. Achieving a balanced portfolio of fuels and technologies best manages a variety of risks, including commodity price volatility, fuel supply disruptions, and changes in regulatory practices. (Reference 3) Consequently, Virginia law governing electric utility resource planning calls for the integrated resource plan (IRP) that DVP has, and that it must continue to "reflect a diversity of electric generation and supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources…." (Va. Code § 56-598(3)). The Energy Policy Act of 2005 also includes provisions for utilities to develop plans to minimize their dependence on one fuel source by requiring them to use a diverse range of fuels and technologies in meeting their customer energy requirements. (Energy Policy Act of 2005 (Pub. L. 109-58) (Aug. 8, 2005)). In fact, a balanced energy portfolio has been the key to providing the U.S. with a growing supply of affordable electricity for the past 30 years. (Reference 4)

Fuel diversity is using a balance of fuel mixes. Each potential generation fuel has merits and risks related to price volatility, transportation, and supply disruptions that need to be considered in long-term planning. In 2005 and 2008, natural gas prices were at all-time highs; however, due to fundamental changes in technology used to extract natural gas from shale formations, combined with mild winter weather, prices reached historic lows in 2012. Coal prices, while not as volatile as natural gas, have also experienced price swings related to various domestic and international issues, such as global supply disruptions, new environmental regulations, increasing extraction cost, and, at least for some eastern coals, a general decline in the minable resource base. The

1. As stated in Appendix 3D of the 2012 IRP, Dominion's nuclear units in Virginia operated with an average capacity factor of 90% from 2009 to 2011. (Reference 2)

price swings experienced in the natural gas and coal markets during the last 10 years illustrate the need for consideration of fuel diversity in long-term planning of the generation fleet.

Utilities require a mix of generation technical capabilities to meet the complexity of the load-following requirements to keep on their customers' lights. (Reference 5) Generation units' capabilities vary, as some units, such as natural gas-fired combustion turbines, are designed to start and ramp-up to full capacity in a short period of time, while running at relatively low capacity factors to meet system peak loads. Baseload generation, such as nuclear units, run reliably for long periods of time at a consistent level of output. Utilities must have a mix of generation, not only for fuel diversity, but simply to have the right combination of technologies to meet their customers' loads reliably. (Reference 5)

Generation planning horizons are long-term outlooks with diverse generation assets and types (fuel) providing a hedge against risks that are too long-lived to be covered by short-term outlooks for fuel prices or forward commodity markets. A diverse generation fleet is useful to mitigate uncertainties when traditional risk management tools are not available. For example, there is no negatively correlated asset to materially hedge potential risk such as CO_2 regulation, and there is not yet a clear timeframe for exactly when and to what extent such hedges may be needed. A diverse fleet of generation options including nuclear and renewable sources will most reasonably address this type of uncertainty.

Diversity can also provide risk mitigation related to unforeseen changes in policy directions. For example, EPA's proposed New Source Performance Standard for carbon dioxide (CO_2) requires new fossil fuel electric generators to meet an output-based standard for CO_2 emissions that is roughly equivalent to the emissions level of a gas-fired combined cycle plant. Because Carbon Capture and Sequestration (CCS) would be required for a new coal plant to meet this standard, this rule essentially eliminates new coal plants as a fuel diversity option until CCS technology is proven and economic. This limits the generation diversity options to natural gas, nuclear, and renewable technologies and cost effective load growth reduction programs. Until CCS technology is proven and economic, nuclear generation is one of a few remaining dispatchable baseload generation options available to mitigate long-term risk associated with unforeseen changes in fuel prices and policy.

The existing coal generation fleet in the eastern U.S. is currently undergoing a significant transformation driven by low gas prices, an aging fleet, and effective and anticipated environmental regulations. As a result, 16 GW of coal units have retired since 2008, and 19 GW of additional coal plants have announced plans to retire over the next 3 to 5 years. The Company is no different and plans to retire 856 MW of coal-fired generation by 2015. Longer term, the eastern U.S. coal fleet faces another challenge, with approximately 60 percent of the remaining coal units being in operation for over 50 years by 2025. Since 2008, only 9 GW of new coal generation has been built or is currently under construction. Replacing the retiring capacity will require new baseload generation. Considering the restrictions on new coal plant construction and these noted retirements, nuclear generation is needed to sustain a diverse and reliable baseload generation option. See Figure 8.0-1 regarding coal generation.

The operating licenses for the existing fleet of U.S. nuclear power generation begin to expire en masse in the 2030s with 37 percent of the licenses expiring by the end of 2030 and 64 percent expiring by the end of 2035. Dominion's nuclear plants' operating licenses for North Anna (Units 1 and 2) and Surry (Units 1 and 2) will also expire in the 2030s. While some additional license renewals are possible, replacing any significant portion of this U.S. fleet will require careful consideration of long-term plans to assure the generation fleet remains diverse in fuel type and technology. See Figure 8.0-2 regarding nuclear generation.

As noted earlier, the price for natural gas has recently been at historically low levels. This has prompted an interest in developing new generation plants fired by natural gas. Gas generation development, since 2008, has represented the majority of new generation constructed in the eastern U.S., with 25 GW of new gas-fired generation put into service since 2008 and an additional 5 GW under construction. Review of recent Integrated Resource Plans for utilities in the eastern U.S. indicate another 13 GW of gas-fired generation are included in their long-term plans. Additionally, 7 GW of coal units are converting to gas as the primary fuel. Low prices allow for the build-out of natural gas generation as the most attractive option over the short-term. DVP remains positive on natural gas and believes in its supply, reliability, environmental benefits, and transportation systems to support the electric generation fleet. However, when considering the longer-term perspective, it is not prudent to expect natural gas to overcome the decrease in fuel and operational diversity created by coal and nuclear retirements, as well as increasing electricity demand. New nuclear must remain an option to provide reliable electricity within Virginia. Long-term perspectives require nuclear project development to be underway to assure the nuclear option remains available to continue a diverse fleet of generation units. See Figure 8.0-3 regarding gas generation.

8.0.1.3 **Emissions Avoidance**

Fossil fuel-fired electrical generation plants produce more air emissions (e.g., nitrogen oxides, sulfur dioxide, and carbon dioxide) associated with air quality, climate change, aesthetic and health concerns than nuclear energy. As shown in Figure 8.0-4, electricity generated by nuclear power provided approximately 20 percent of the total electricity generated in the U.S. in 2010 without any appreciable air emissions.

Beyond steam and water vapor, modern nuclear reactors produce virtually no air emissions. Nuclear power generation, therefore, leads to significant local, national, and global air quality benefits. (Reference 7) Section 9.2 and NUREG-1437 Supplement 7, Section 8.2 compare the emissions from coal- and gas-fired alternatives. (Reference 8)

8.0.1.4 **Carbon Dioxide Emissions**

The 2007 Virginia Energy Plan (Reference 11) established the goal to reduce carbon dioxide emissions by 30 percent by 2025, bringing emissions back to 2000 levels. Currently, nuclear power is the only available and proven technology that provides a viable alternative to fossil-fired plants for baseload electrical generation. Unit 3 will significantly contribute to the achievement of Virginia's goal to reduce carbon dioxide emissions.

8.0.1.5 **Tax Revenues**

Taxes are transfer payments that would share and distribute the economic benefit of Unit 3 with state and local governments. While tax revenues are not independent benefits, they are described below to properly describe the allocation of benefits.

The proposed NAPS Unit 3 would make tax payments to the Commonwealth of Virginia and counties for the 40 operating years of the license. Additionally, in 2006, Virginia Economic Development Partnership (VEDP) used IMPLAN, a commercially available input-output modeling program, to estimate the economic impact of the jobs created by the addition of a new nuclear generating unit at the NAPS. (Reference 1) Dominion provided the following key parameters for this analysis: 750 new direct jobs during the plant operation period with an average annual salary of $67,000 and 2,000 direct jobs during the construction period.

During the plant construction period, VEDP estimates that the direct and additional jobs created due to construction of a new unit at NAPS should generate annually $4.8 million in state tax revenue and $3.5 million in tax revenue for the local counties. Tax revenue for the local counties consists of $3.1 million in property taxes and $400,000 in sales and use taxes annually. At the above rate, the direct and additional jobs due to the proposed Unit 3 should result in $24.9 million in total tax revenues to the Commonwealth of Virginia and local counties over the projected 3-year construction period. This amount consists of $14.4 million in total state taxes to Virginia, $9.3 million in total property tax and $1.2 million in total sales and use tax revenues allocated to the local counties.

During the plant operation period, VEDP estimates that the direct and additional jobs created due to a new unit at NAPS should generate annually $14.8 million in state tax revenue and $27.7 million in tax revenue for the local counties. Tax revenue for the local counties consists of $3.5 million in property taxes and $24.2 million in sales and use taxes annually. At the above rate, the direct and additional jobs due to the proposed Unit 3 should result in $1.7 billion in taxes to the Commonwealth of Virginia and the local counties over the 40-year operating license. This amount consists of $592 million in total state taxes to Virginia, $140 million in total property tax and $968 million in total sales and use tax revenues to the local counties.

The additional tax revenues generated from construction and operation of Unit 3 should benefit the state and local county government agencies because the revenues would support the development of infrastructure and services that support the community and promote further economic development.

8.0.1.6 Local and State Economy

The construction of NAPS Unit 3 would require a workforce of about 2000 people (conservatively estimated) and would generate additional income for the Commonwealth of Virginia and local economy for a period of three years. The subsequent operation of the proposed Unit 3 would require an operational workforce of about 750 people and would generate additional income and value for the Commonwealth of Virginia and local economy for a period of at least 40 years.

Based on the VEDP estimates, (Reference 1) the construction and operation of the proposed Unit 3 would increase the Commonwealth of Virginia's economic output by $42.5 million annually. If the direct value of the new unit output is included, state and county output attributable to the operation of Unit 3 would be significantly higher.

VEDP estimates (Reference 1) that the construction of the proposed Unit 3 would require the hiring of 2000 workers during three years of construction, some of which are expected to come from outside the local area. These construction workers and their employers would pay income taxes and support additional employment in the local areas through their spending. VEDP estimates that 1236 additional indirect jobs would be created as a result of the construction. Temporary construction workers and their families increase rental and property demand, spending on goods and services, and sales taxes that benefit the local economy.

In addition, VEDP estimates (Reference 1) that the operation of Unit 3 would create 750 direct jobs for Louisa County for 40 years. These permanent operational workers would pay income taxes and support additional employment in the local areas through their spending. VEDP also estimates that 1553 additional indirect jobs would be created as a result of operation of Unit 3. The communities potentially impacted socio-economically by construction and operation of Unit 3 are Louisa, Orange, and Spotsylvania Counties, all in central Virginia. Louisa County, where NAPS is located, would see the greatest impact. All these counties have experienced steady growth in population and economic activity during the last decade. Moreover, an additional nuclear unit will increase career opportunities within Dominion's nuclear organization, allowing for new opportunities in the nuclear operations for entry-level employees, as well as additional opportunities for promotion and retention of the exceptionally qualified staff.

8.0.1.7 Other Benefits

Section 10.3 (also ESP-ER Section 10.3) describes the relationship between short-term uses and long-term productivity of the human environment. These benefits are summarized in Table 8.0-1.

Section 8.0 References

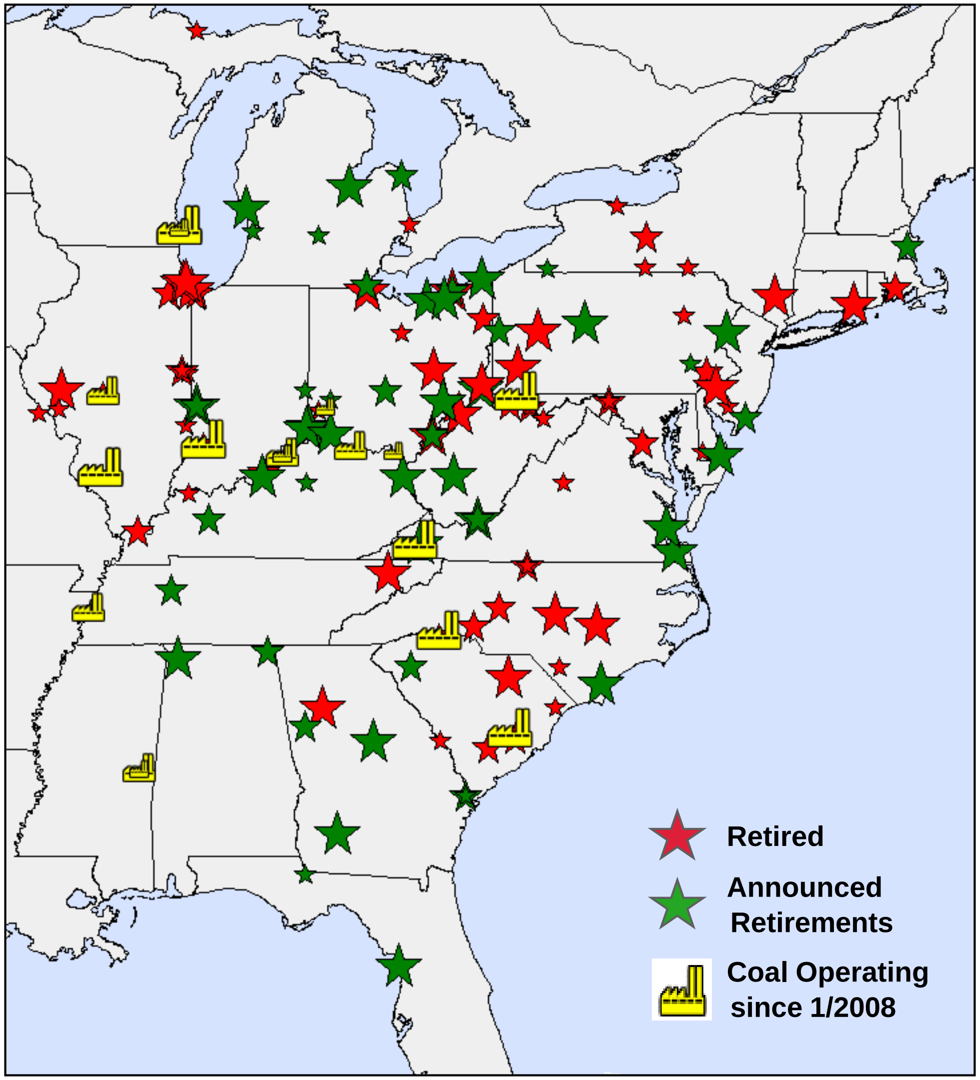
1. Virginia Economic Development Partnership, “The Estimated Economic Impact of an Expansion of the North Anna Power Station on Virginia,” November 14, 2006.
2. DVP, “Dominion North Carolina Power and Dominion Virginia Power's Integrated Resource Plan: Chapter 3.2”, August 31, 2012.
3. Edison Electric Institute (EEI) website, “Fuel Diversity,” 2006.
4. Center for Energy and Economic Development (CEED) website, “Fuel Diversity,” 2006.
5. Edison Electric Institute (EEI), “Utility Supply Portfolio Diversity Requirements,” May 2007.
6. [Deleted]
7. Massachusetts Institute of Technology (MIT), “The Future of Nuclear Power, An Interdisciplinary MIT Study,” report, 2003.
8. U.S. Nuclear Regulatory Commission, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 7, Regarding North Anna Power Station, Units 1 and 2,” Final Report, NUREG-1437, November 2002.
9. [Deleted]
10. [Deleted]
11. Commonwealth of Virginia, Department of Mines, Minerals and Energy, “The Virginia Energy Plan,” September 12, 2007.

Table 8.0-1 Monetary and Non-Monetary Benefits of NAPS Unit 3

Category of Benefit	Description of Benefit
Net Electrical Generating Benefits	
Net Generating Capacity	~1,500 MWe
Electricity Generated (operating at 90% cap.)	~12,000,000 MW-hrs
Taxes and Revenue During Plant Operation Period (Transfer Payments - Not Independent Benefits)	
Annual State Taxes	NAPS Unit 3 pays $14.8 million.
Annual Property Taxes	NAPS Unit 3 pays $3.5 million.
Annual Sales Taxes	NAPS Unit 3 pays $24.2 million.
Effects on Regional Productivity	
Construction Workers	Approximately 2,000 workers create an incremental increase of 1,236 indirect jobs, within the region.
Operational Workers	750 new workers create an incremental increase in 1,553 indirect permanent jobs within the region for at least 40 operating years.
Socioeconomics	Increased tax revenue supports improvements to public infrastructure and social services. The increased revenue spurs future growth and development.
Technical and Other Non-Monetary Benefits	
Fuel Diversity	Reduces exposure to supply and price risk associated with reliance on any single fuel source.
Price Volatility	Dampens potential for fuel price volatility.
Fossil Fuel Supplies	Offsets usage of finite fossil fuel supplies.
Electrical Reliability	Enhances electrical reliability.
Emissions Reduction	Significant beneficial impact in terms of avoidance of air emissions.
Carbon Dioxide Emissions	Baseload generation with virtually no carbon dioxide emissions.
Wastes	Compared with fossil-fueled plants, nuclear plants produce less nonradioactive waste products.

Table 8.0-2 Deleted

Figure 8.0-1 Eastern U.S.* Coal Generation Developments 2008 through March 2013



Coal Retirements – 35 GW

- 16 GW retired since 2008
- 19 GW of additional retirements announced

New Coal – 9 GW

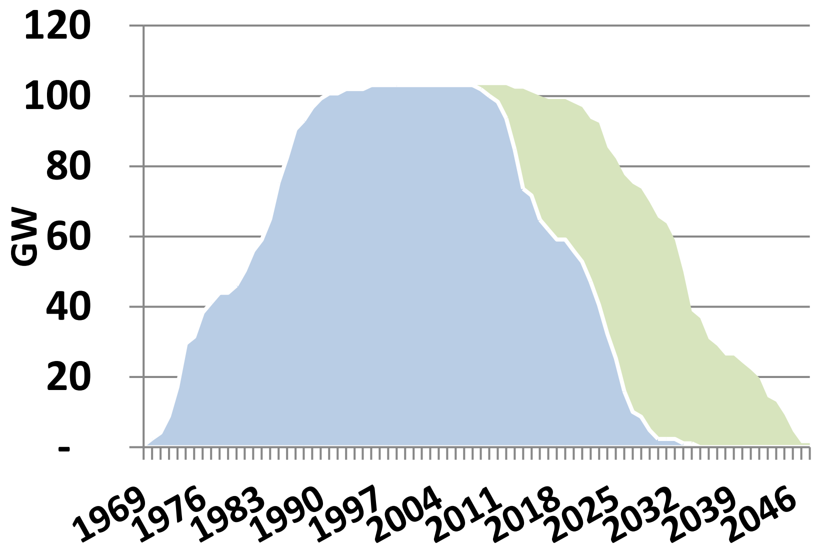
- 8 GW new coal online Since 2008
- 1.2 GW currently under construction
  - Both IGCC Units

Future coal development unlikely given the GHG NSPS Ruling

- Limits GHG emission rates on new units to gas fired combined cycle equivalent
- Requires development of Carbon Capture and Storage technology

* Eastern U.S. includes NERC Regions RFC, NPCC, SERC and FRCC
Source: Energy Velocity and internal Dominion research

Figure 8.0-2 Fuel Diversity: U.S. Commercial Nuclear Power Reactor Generation Capacity/Gas Supplementation



Combination of Coal Retirements, Nuclear Retirements, and Demand Growth Will Challenge Any Single Source Fuel Option

2012 Stats

24 TCF - Annual U. S. Natural Gas Production

9.1 TCF – Gas Consumption by Electric Generation

- 38% of U.S. Production

Nuclear Replacement Scenario

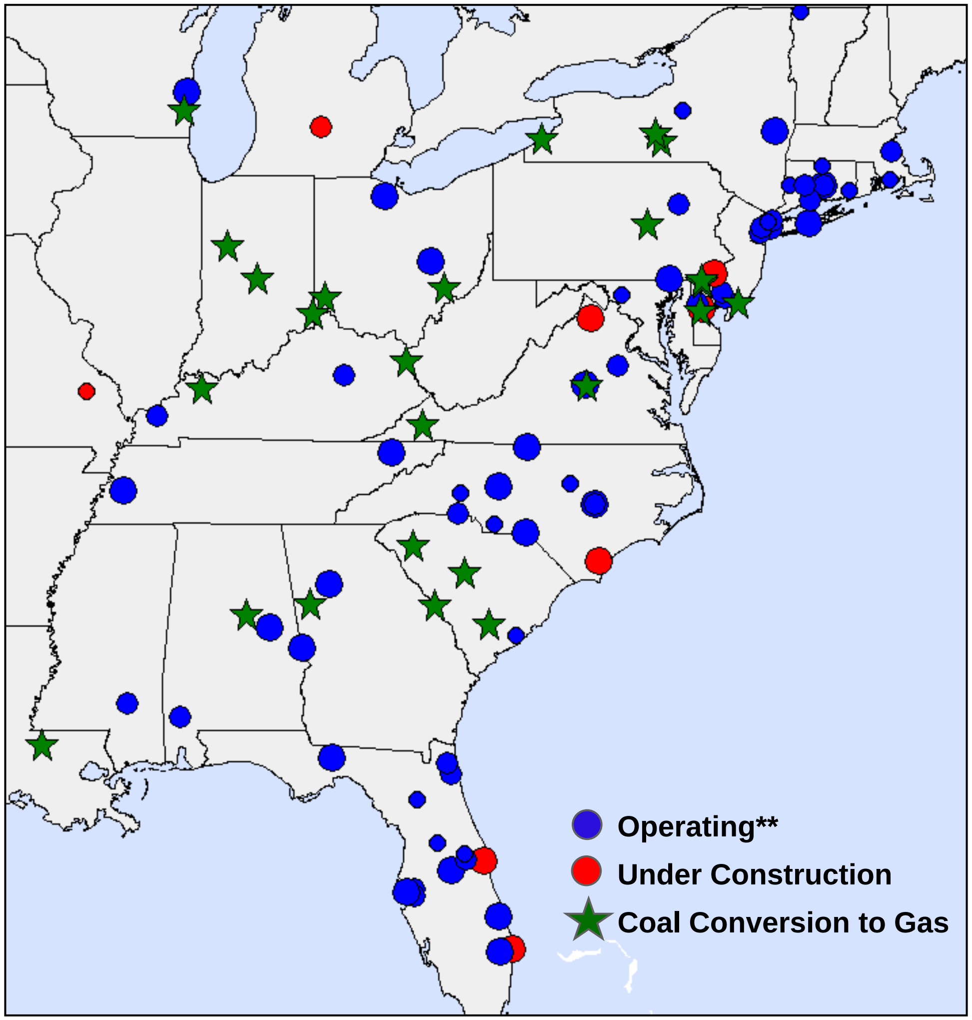
5.5 TCF – Natural Gas Required to Replace Nuclear

- 23% of U.S. Production

14.6 TCF - Combined 2012 Electric Sector Gas Consumption and Nuclear Replacement

- 60% of U.S. Production

Figure 8.0-3 Eastern U.S.* Gas Generation Development 2008 Through March 2013



32 GW - New Gas

- 25 GW in service since 2008
- 5 GW under construction
- 2 GW cleared PJM BRA, but not under construction

7 GW -Coal to Gas Conversions

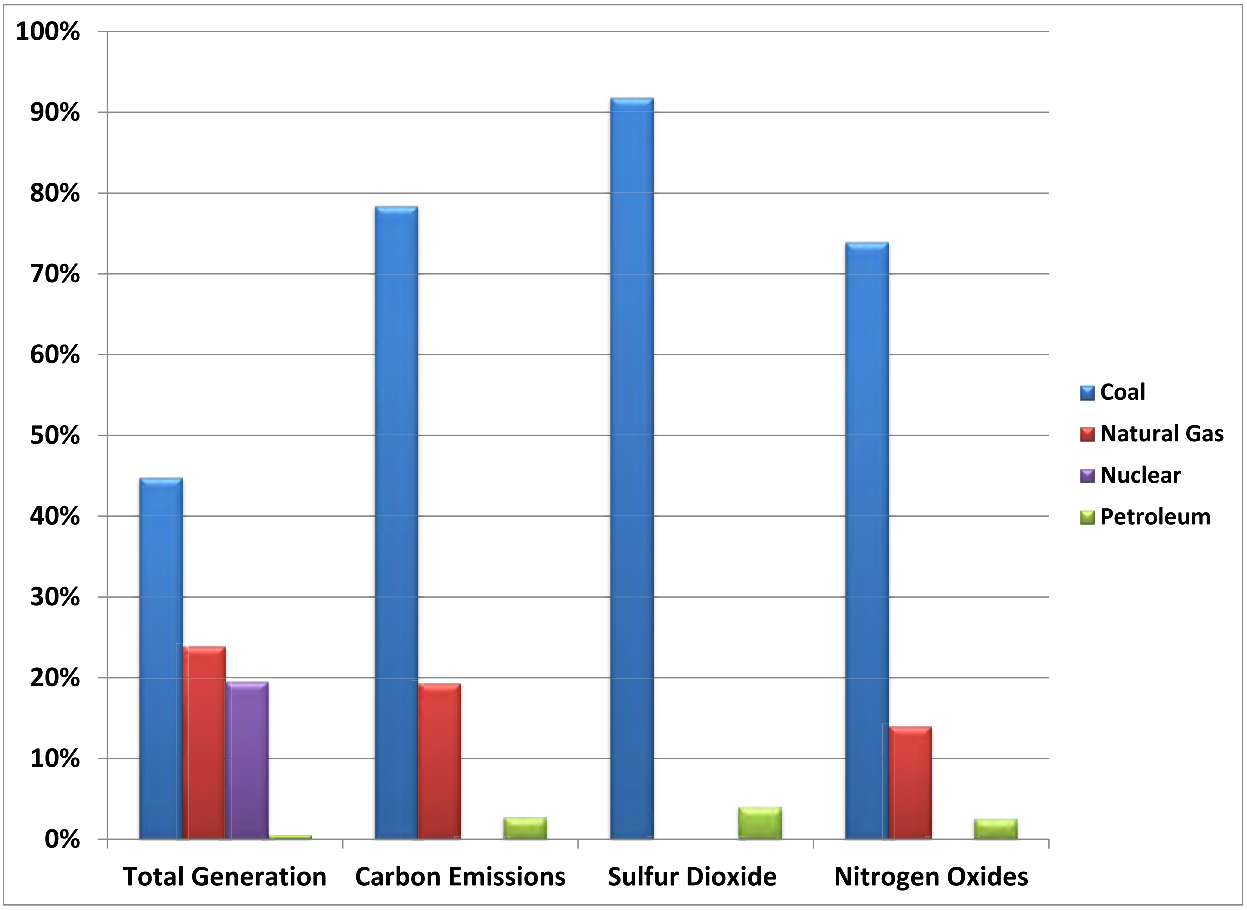
- Coal units with announced plans to convert to gas

~13 GW - Gas generation included in long term plans of regulated utilities

- Included in IRPs
- Not shown on map

* Eastern U.S. includes NERC regions RFC, NPCC, SERC and FRCC
** Gas unit in service after Jan 1, 2008
Source: Energy Velocity and internal Dominion research

Figure 8.0-4 Total U. S. Generation and Air Emissions from Electricity Generation 2010



Source: Graph generated with EIA data, including Form EIA-923, Power Plant Operations Report, Form EIA-906, Power Plant Report, Form EIA 920, Continued Heat and Power Plant Report and predecessor forms.

8.1 Power System

This section describes and assesses the regional power system in which the proposed facility would operate. This section describes: i) DVP's transmission zone (also referred to as either Dominion Zone or PJM South Region (Figure 8.1-1)); ii) DVP's electric distribution service territory; iii) the PJM market, in which DVP operates and of which DVP's transmission zone is a part; and iv) the Regional Reliability Organization—SERC Reliability Corporation (SERC)—to which DVP belongs. This section also defines the appropriate region of interest for assessing the need for power. As discussed further below, legislation was passed in Virginia that redefined investor-owned electric utilities' native load obligations.

8.1.1 Region of Interest – Dominion Zone

In May 2005, DVP joined PJM and transferred control of the transmission facilities that it owns and operates in its control area to PJM. With its integration into PJM, DVP separated its electric generation and traditional customer delivery businesses into two distinct operations within PJM's system. The region of interest (ROI) for the purposes of this COL Application is the Dominion Zone which also includes the electric distribution service territories comprised of DVP, ODEC, North Carolina Electric Cooperatives (NCEMCS) and other municipals. DVP operates as the principal load serving entity or LSE in the Dominion Zone.

DVP serves approximately 90 percent of the electric load in the Dominion Zone including both peak demand and total energy requirements.[1] The need for power analysis presented in Section 8.4 relies upon baseload growth projections based on historical growth observed by DVP in the Dominion Zone.

8.1.2 Deleted

8.1.3 DVP's Electric Service Territory

DVP's electric service territory encompasses most of the population of the Commonwealth of Virginia as well as sections of North Carolina (see the shaded area in Figure 8.1-3). DVP's service territory in Virginia comprises about 65 percent of the state's total land area, but accounts for over 80 percent of its total load and includes one of the fastest growing counties in Virginia. (Reference 3) In North Carolina, DVP serves the northeastern corner of the state excluding several municipalities. As discussed in Section 8.1.3.1, DVP has native load obligations throughout its service territory in Virginia and North Carolina.

DVP serves the fast-growing Northern Virginia area. This area comprises the counties of suburban Washington DC, one of which, Loudoun, was named one of 100 fastest-growing counties in the

1. This assessment is based on analysis of DVP's 2012 actual peak demand and annual energy compared to 2012 historical PJM integrated hourly loads for the Dominion Zone (Reference 9).

nation according to the U.S. Census Bureau. (Reference 10) In addition, DVP's service territory includes the cities of Richmond, Norfolk, Williamsburg, Fredericksburg, Virginia Beach, and Charlottesville.

The estimated population for the Commonwealth of Virginia as of July 2012 was 8,185,867 as published by the U.S. Census Bureau (Reference 11) and is on pace for approximately 0.98 percent - 1.8 percent per annum growth based on the growth experienced from 2007 to 2012. DVP estimates that its Virginia service territory population has grown at about 1.1 percent - 1.9 percent per annum since 2007, leading to its 2012 population estimate of 6,853,425.[1]

The population growth for the state of North Carolina has ranged from about 0.96 percent–2.0 percent per annum since 2007, to the Census Bureau's July 2012 estimate of 9,752,073. (Reference 12) Population growth in the counties in which DVP's service territory is located in North Carolina has ranged from about 0.1 percent - 4.0 percent per annum since 2007, to the 2012 estimate of 592,969.

The estimated population growth rates for counties in which DVP has service territory are outlined in Table 8.1-1, and the counties and cities in which DVP's service territory is located are listed in Table 8.1-2. DVP expects significant growth in baseload requirements through new customer additions, which DVP estimates at approximately 35,000–40,000 new customer connections each year, and data center growth of 455 MW from 2013 to 2017. (Reference 4)

The breakdown of residential, commercial and industrial customers served by DVP as reported by the EIA in its EIA-861 database is provided in Table 8.1-3. Roughly 40 percent of the total load reported was residential, 50 percent was commercial (public authority) and the remaining 10 percent industrial.

Electric sales by class have been impacted by the recent recession and abnormal weather patterns over the past several years as shown in Table 8.1-3. However, both PJM and DVP project an increase in weather normalized total electric sales (output) over the next 15 years. The economic fundamentals in the Commonwealth of Virginia remain strong which are primary drivers of electric consumption. The majority of the growth is expected to come from the residential and commercial classes. The increase in residential class electric sales is expected to reflect increases in disposable income, lowered unemployment and increased housing starts, while the commercial sector is expected to be driven largely by data centers. Data centers, located in the Commonwealth, have contributed to the share of commercial class sales and are expected to continue that trend. Data centers are large commercial, high load-factor customers that contribute to baseload need requirements. Data center electricity usage is projected to grow rapidly over the next decade as information storage and availability requirements expand.

1. This estimate was developed by cross referencing the population estimates published by the U.S. Census Bureau and resulting growth rates with information published in the EIA-861 database regarding the counties where DVP distributes electricity.

8.1.3.1 Status of Electricity Market Reforms in DVP's Service Territory

In 2007, the Virginia General Assembly passed House Bill 3068 and Senate Bill 1416 (the Legislation), which were signed into law by Virginia's governor. A primary objective of the Legislation, also know as the Virginia Electric Utility Regulation Act (the Regulation Act), is to ensure a reliable and adequate supply of electricity by investor-owned electric utilities for their native load obligations[1] and to return Virginia's electric system to an incentive form of "cost-of-service" regulation beginning July 1, 2007. One of the goals of the Regulation Act is to encourage the construction of new baseload generation, including nuclear generation, to serve in-state system requirements by providing higher rates of return on common equity for these facilities. North Anna Unit 3 is being developed to meet native load obligations pursuant to the Regulation Act. This Legislation also requires that 75 percent[2] of the total annual margins from off-system sales be applied to the utility's fuel expenses, reinforcing that these facilities are primarily intended to serve native load customer requirements.

The 2013 Virginia General Assembly passed House Bill 2261 amending the Regulation Act. The amendments became effective upon the governor's signature in February 2013. House Bill 2261 preserved the central elements of the Regulation Act. House Bill 2261 retains enhanced rates of return for nuclear and offshore wind generation projects, consistent with the General Assembly's strong interest in promoting these forms of generation, including new nuclear units.

DVP and other electric utilities in North Carolina have continued to be responsible for supplying their native load obligations. (Reference 13)

8.1.4 Dominion Zone Oversight

The Dominion Zone is subject to oversight from four separate entities with respect to reserve margin standards, system reliability, and planning. A summary of each entity's oversight function is provided below.

8.1.4.1 Deleted

8.1.4.2 PJM

PJM is an independent regional transmission organization (RTO) responsible for operating the wholesale energy market in the largest centrally dispatched control area in North America

1. There are approximately 111 Virginia jurisdictional customers with loads greater than 5 MW representing a total coincident peak load of approximately 980 MW and these customers may, if they choose, purchase power from other providers. In addition, the Legislation allows non-residential customers to aggregate their loads to greater than 5 MW and be served by a competitive supplier.
2. The Virginia State Corporation Commission may require less than 75 percent of such margins to be so credited if it finds by clear and convincing evidence that such a requirement is in the public interest.

encompassing all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia (see Figure 8.1-4). PJM also has primary responsibility for administering a long-term PJM Regional Transmission Expansion Planning (RTEP) and the Reliability Pricing Model (RPM) which provides a long-term price signal for existing and new generating capacity resources to ensure reliability for the PJM control area. As a PJM member, DVP, as a LSE, is a signatory to PJM's Reliability Assurance Agreement among Load Serving Entities in the PJM Region (RAA),[1] which obligates DVP to own or procure an amount of capacity in order to maintain overall system reliability. (Reference 7) The process and framework established by PJM's RAA is a comprehensive and rigorous method for ensuring the reliability of resources in the Dominion Zone. PJM performs a technical analysis on an annual basis that calculates the appropriate generating capacity including reserve margin required to meet the RAA-defined reliability criteria.[2] This technical analysis is based on a loss of load expectation (LOLE) of one day in ten years, which is also the standard adopted by SERC and the Reliability First Corporation (RFC), which is the regional reliability organization which covers much of the PJM market. The Installed Reserve Margin (IRM) is determined annually and is vetted at various stakeholder forums including the Resource Adequacy Analysis Subcommittee, Planning Committee, Markets and Reliability Committee and the Members Committee. If approved by the stakeholders, it is then forwarded to the PJM Board for final approval. The IRM for future years (as shown in 2012 PJM Reserve Requirement Study (Reference 8)) averages 15.6%. This region-wide IRM target is used for RPM and is the basis for allocating a capacity obligation to each LSE within PJM based on that LSE's share of the PJM summer peak load.

Each LSE is responsible for installing or purchasing capacity, on a daily basis, to meet its obligation. The rationale for imposing capacity obligations on PJM LSEs is that installation of generating capacity requires time, coordination of electric system resources, and financial backing and, therefore, must be planned for in advance of need. To meet its capacity, long-term reliability obligations and customer energy requirements within PJM in a cost-effective manner, DVP is developing North Anna Unit 3 and proposing to build the Brunswick facility, as well as Warren County Power Station, which is under construction.

In order to balance the requirements of buyers and loads with offers of suppliers and by so doing manage the reliability of the system, PJM administers an hourly market (both day ahead and real time) for energy and the RPM annual market for capacity. While the energy market is designed to balance day-to-day (and hour-to-hour) supply and demand within PJM, the RPM capacity market is

1. Parties previously have entered into similar commitments related to sub-regions of the PJM Region through the East RAA, the West RAA, and the South RAA. In June 2007, these agreements were replaced with a single reliability assurance agreement among all Load-Serving Entities in the PJM Region. (Reference 7)
2. PJM outlines the process for establishing a reserve margin target and allocating responsibility for meeting this target among members in its Manual 20.

designed to provide a price signal to ensure that the long-term peak requirements of the PJM system can be met by available capacity resources. PJM defines the purpose of the RPM market as "to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the RTEP." (Reference 14)

The Dominion Zone is one of the 26 Locational Deliverability Areas (LDA) in PJM. These 26 LDAs, most of which reflect service territory boundaries of PJM member electric utilities, were identified by PJM's load deliverability analyses conducted pursuant to the RTEP protocol and the PJM Manuals as "constrained areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations." (Reference 7) Each of the 26 LDAs are modeled in the RPM Base Residual Auction. Capacity to serve LSEs in constrained areas must be located within the constrained area or the LSE must enter into a bilateral transaction for capacity into the constrained area with another entity through Capacity Transfer Rights (CTRs). A discussion of the capacity resources located in the Dominion Zone is presented in Section 8.3.

8.1.4.3 **Virginia SCC**

As discussed in Section 8.1.3.1, in 2007 the Virginia General Assembly significantly amended the Virginia Utility Electric Restructuring Act, Code of Virginia (Title 56, Chapter 23), in large part to accommodate amendments designed to ensure reliable and adequate supply of electricity. The amended statute known as the Virginia Electric Utility Regulation Act, or the Regulation Act, "was further amended by the Virginia General Assembly in 2008, with the addition of language (Va. Code §§ 56-597 through 56-599) requiring each electric utility to file every two years an Integrated Resource Plan (IRP) with the Virginia SCC.[1] The Plan shall present the utility's forecast of demand for its electric supply obligations over the ensuing 15 years and its plan to meet these obligations "by supply side and demand side resources" in a manner that promotes "reasonable prices, reliable service, energy independence, and environmental responsibility." (Va. Code § 56-597).

Among other requirements, the utility's Plan must "[i]dentify a portfolio of electric generation supply resources, including purchased and self-generated electric power…." (Va. Code § 56-598). Additionally, the portfolio must "[r]eflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources…." (Id.). The Virginia SCC must consider and rule on the application for the CPCN that DVP must file for Unit 3. Under Va. Code §56-580.D, a utility must demonstrate to the Virginia SCC that a proposed facility: i) will have no material adverse effect upon reliability of electrical service provided by any regulated public utility, ii) is required by the public convenience and necessity, and iii) is not otherwise contrary to the public interest.

1. Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan filed on August 31, 2012 (2012 IRP) is available at: www.dom.com/about/pdf/irp/irp-083112.pdf

As prescribed by the Virginia General Assembly, the Virginia SCC also has the responsibility to fix, for each Virginia public utility, just and reasonable rates that it may charge for its services to its customers. The Virginia SCC also has authority over the manner in which the utility companies provide service to their customers and requires public utilities to provide reasonable and reliable service and to adopt safety rules and regulations for the protection of the public.

8.1.4.4 **North Carolina Utilities Commission (NCUC)**

The NCUC requires all public utilities to first obtain a certificate of public convenience and necessity from the NCUC before beginning the construction or operation of any utility plant or system in North Carolina or acquiring ownership or control thereof. In August 2007 the Governor of North Carolina signed into law Senate Bill 3 (Session Law 2007-397) for generation facilities constructed outside of North Carolina. The law provides for utilities to petition the NCUC for approval of the estimated construction schedule and costs if an out-of-state plant is needed and intended to serve North Carolina customers. The law also contains provisions regarding review of the development costs for nuclear generation.

As a general rule, the NCUC has the responsibility under the law to fix, for each North Carolina public utility, the rates that it may charge for its services to its customers. These rates are required to be just and reasonable and fair both to the public utility and to its customers. In addition, the NCUC has authority over the manner in which the utility companies provide service to their customers and requires public utilities to provide reasonable and reliable service and to adopt safety rules and regulations for the protection of the public. (Reference 16)

8.1.4.5 **SERC**

DVP's service territory is located in the Virginia-Carolinas (VACAR) sub-region of SERC (Figure 8.1-6). (Figure 8.1-5 identifies the area covered by SERC.) SERC is responsible for proposing and enforcing reliability standards within the SERC region based on authority delegated to it from the North American Electric Reliability Corporation. SERC is also responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in the SERC region. SERC promotes the development of reliability and adequacy arrangements among the power supply systems; administers a regional compliance and enforcement program to achieve the reliability benefits of coordinated planning and operations; and provides a mechanism to resolve disputes on reliability issues. (Reference 6)

Section 8.1 References

1. [Deleted]
2. [Deleted]
3. Dominion website, "Dominion Virginia Power," May 14, 2013.
4. DVP, "Investor and analyst Meeting," March 4, 2013.
5. [Deleted]
6. SERC Reliability Corporation, "The Region," May 7, 2013.
7. PJM Interconnection, LLC, "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," report, January 4, 2013.
8. PJM Interconnection, LLC, "2012 PJM Reserve Requirement Study," October 5, 2012.
9. PJM Interconnection, LLC, "Hourly Load Data, 2012," from a website database.
10. U.S. Census Bureau, Population Division, "Table 4: Housing Unit Estimates for the 100 Fastest Growing U.S. Counties with 5,000 or more housing units in 2010: April 1, 2010 to July 1, 2011," HU-EST2011-04, May 7, 2013.
11. U.S. Census Bureau, Population Division, "Table 1: Annual Estimates of the Population for Counties of Virginia: April 1, 2010 to July 1, 2012," May 7, 2013.
12. U.S. Census Bureau, Population Division, "Annual Estimates of the Resident Population of North Carolina: April 1, 2010 to July 1, 2012," May 7, 2013.
13. North Carolina Utilities Commission website, "Electric Industry Restructuring," May 8, 2013.
14. PJM Interconnection, LLC, "Reliability Pricing Model (RPM) Business Rules," report, May 14, 2013.
15. [Deleted]
16. North Carolina Utilities Commission website, "Industries Regulated by the Commission," May 8, 2013.
17. [Deleted]

Table 8.1-1 Population Statistics

Virginia Statistics

	Entire State	Growth	Counties Listed in Table 8.1-2	Growth
7/1/2007	7,719,749	—	6,423,517	—
7/1/2008	7,795,424	.98%	6,492,971	1.1%
7/1/2009	7,882,590	1.1%	6,574,634	1.3%
7/1/2010	8,025,105	1.8%	6,697,245	1.9%
7/1/2011	8,104,384	.99%	6,775,652	1.2%
7/1/2012	8,185,867	1.0%	6,853,425	1.2%

North Carolina Statistics

	Entire State	Growth	Counties Listed in Table 8.1-2	Growth
7/1/2007	9,064,074	—	561,868	—
7/1/2008	9,247,134	2.0%	567,355	0.98%
7/1/2009	9,380,884	1.5%	569,253	0.33%
7/1/2010	9,559,048	1.9%	592,124	4.0%
7/1/2011	9,651,103	.96%	592,703	0.10%
7/1/2012	9,752,073	1.1%	592,969	0.04%

Source: U.S. Census Bureau

Table 8.1-2 List of Counties and Cities Included in Service Territory Estimates

Virginia Counties/Cities	Virginia Counties/Cities (cont'd.)	North Carolina Counties/Cities
Albemarle County	Northumberland County	Beaufort County
Alleghany County	Nottoway County	Bertie County
Amelia County	Orange County	Camden County
Amherst County	Page County	Chowan County
Appomattox County	Pittsylvania County	Currituck County
Arlington County	Powhatan County	Dare County
Augusta County	Prince Edward County	Edgecombe County
Bath County	Prince George County	Gates County
Bedford County	Prince William County	Halifax County
Botetourt County	Richmond County	Hertford County
Brunswick County	Rockbridge County	Hyde County
Buckingham County	Rockingham County	Martin County
Campbell County	Shenandoah County	Northampton County
Caroline County	Southampton County	Pasquotank County
Charles City County	Spotsylvania County	Perquimans County
Charlotte County	Stafford County	Pitt County
Chesterfield County	Surry County	Tyrrell County
Clarke County	Sussex County	Washington County
Culpeper County	Westmoreland County	
Cumberland County	York County	
Dinwiddie County	Alexandria city	
Essex County	Buena Vista city	
Fairfax County	Charlottesville city	
Fauquier County	Chesapeake city	
Fluvanna County	Clifton Forge city	
Gloucester County	Colonial Heights city	
Goochland County	Covington city	
Greene County	Emporia city	

Table 8.1-2 List of Counties and Cities Included in Service Territory Estimates

Virginia Counties/Cities	Virginia Counties/Cities (cont’d.)	North Carolina Counties/Cities
Greensville County	Fairfax city	
Halifax County	Falls Church city	
Hanover County	Franklin city	
Henrico County	Fredericksburg city	
Isle of Wight County	Hampton city	
James City County	Hopewell city	
King And Queen County	Lexington city	
King George County	Manassas city	
King William County	Newport News city	
Lancaster County	Norfolk city	
Loudoun County	Petersburg city	
Louisa County	Poquoson city	
Lunenburg County	Portsmouth city	
Madison County	Richmond city	
Mathews County	South Boston city	
Mecklenburg County	Staunton city	
Middlesex County	Suffolk city	
Nelson County	Virginia Beach city	
New Kent County	Waynesboro city	
	Williamsburg city	

Table 8.1-3 Sales Information by Rate Class

Sales by Rate Class (MW-hr)

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2007	28,890,195	38,215,503	8,349,791	75,455,489	1,578,818	958,645	1,723,634	4,261,097	30,469,013	39,174,148	10,073,425	79,716,586
2008	28,096,943	38,113,267	8,064,086	74,274,296	1,546,418	949,812	1,715,159	4,211,389	29,643,361	39,063,079	9,779,245	78,485,685
2009	28,341,098	38,043,912	7,147,238	73,532,248	1,578,817	953,346	1,496,614	4,028,777	29,919,915	38,997,258	8,643,852	77,561,025
2010	30,821,549	39,012,738	6,872,415	76,706,702	1,716,948	973,584	1,639,786	4,330,318	32,538,497	39,986,322	8,512,201	81,037,020
2011	29,143,896	38,649,800	6,342,210	74,135,906	1,624,886	934,318	1,617,630	4,176,834	30,768,782	39,584,118	7,959,840	78,312,740

Customer Count by Rate Class (#)

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2007	2,004,160	241,253	554	2,245,967	99,867	17,709	66	117,642	2,104,027	258,962	620	2,363,609
2008	2,024,733	244,486	538	2,269,757	100,497	17,766	60	118,323	2,125,230	262,252	598	2,388,080
2009	2,038,871	246,160	522	2,285,553	100,761	17,750	59	118,570	2,139,632	263,910	581	2,404,123
2010	2,056,576	247,036	504	2,304,116	101,005	17,658	56	118,719	2,157,581	264,694	560	2,422,835
2011	2,070,786	248,232	482	2,319,500	101,009	17,662	53	118,724	2,171,795	265,894	535	2,438,224

Table 8.1-3 Sales Information by Rate Class

Average Sales per Customer (MW-hr)

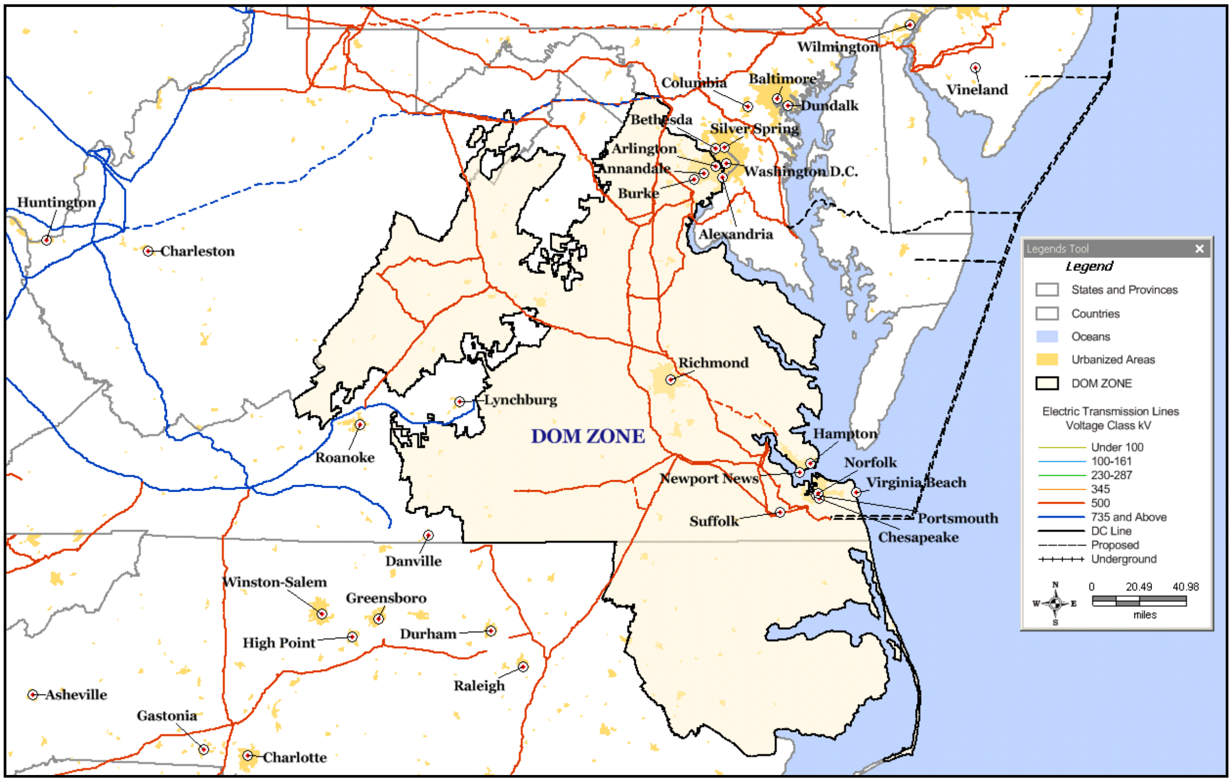
	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2007	14	158	15,072	34	16	54	26,116	36	14	151	16,247	34
2008	14	156	14,989	33	15	53	28,586	36	14	149	16,353	33
2009	14	155	13,692	32	16	54	25,366	34	14	148	14,878	32
2010	15	158	13,636	33	17	55	29,282	36	15	151	15,200	33
2011	14	156	13,158	32	16	53	30,521	35	14	149	14,878	32

% of Total MW-hr by Rate Class

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2007	38%	51%	11%	100%	37%	22%	40%	100%	38%	49%	13%	100%
2008	38%	51%	11%	100%	37%	23%	41%	100%	38%	50%	12%	100%
2009	39%	52%	10%	100%	39%	24%	37%	100%	39%	50%	11%	100%
2010	40%	51%	9%	100%	40%	22%	38%	100%	40%	49%	11%	100%
2011	39%	52%	9%	100%	39%	22%	39%	100%	39%	51%	10%	100%

(Source: EIA-861 Database)

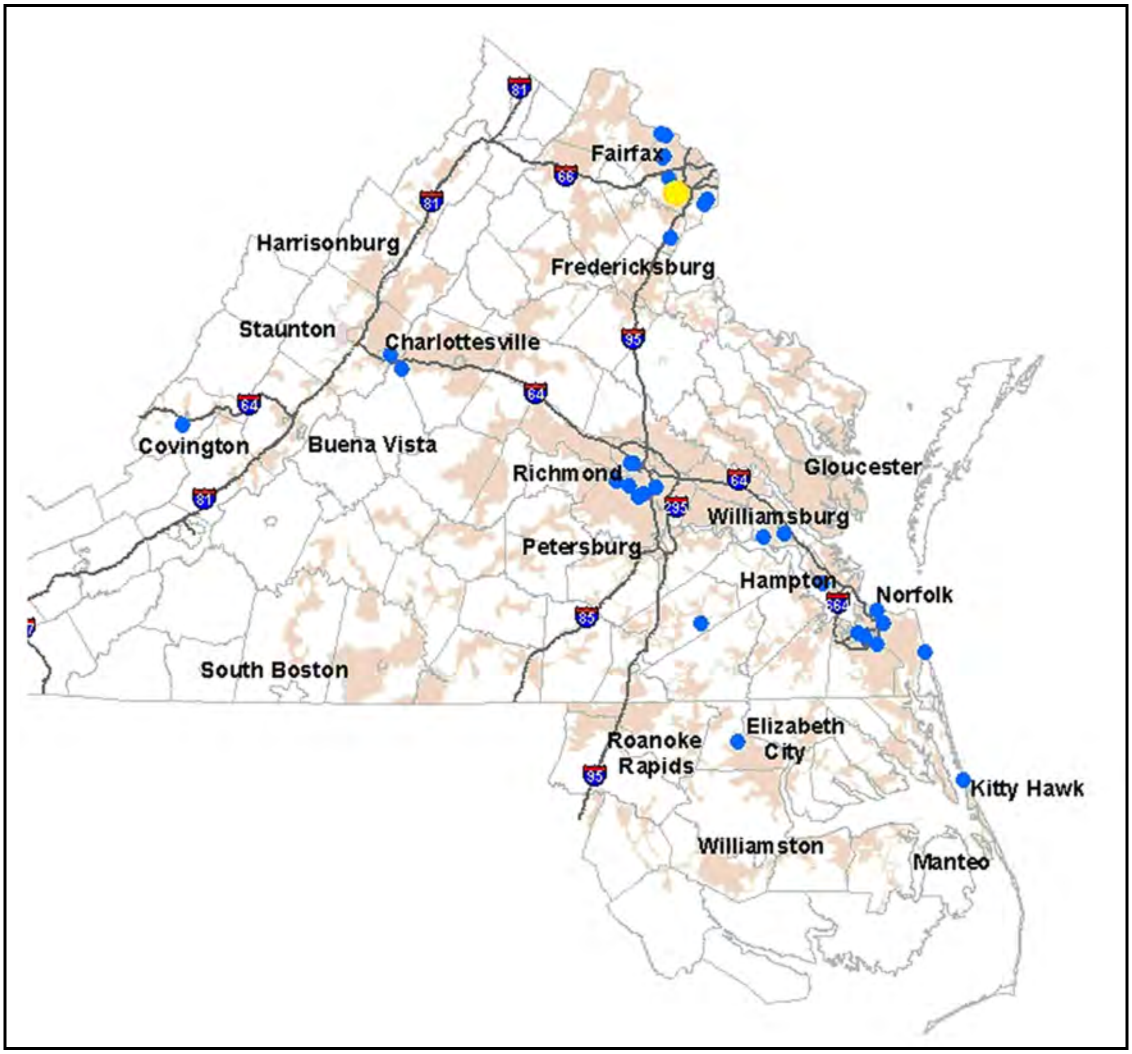
Figure 8.1-1 Map of Major Transmission Lines into Dominion Zone



Source: Energy Velocity

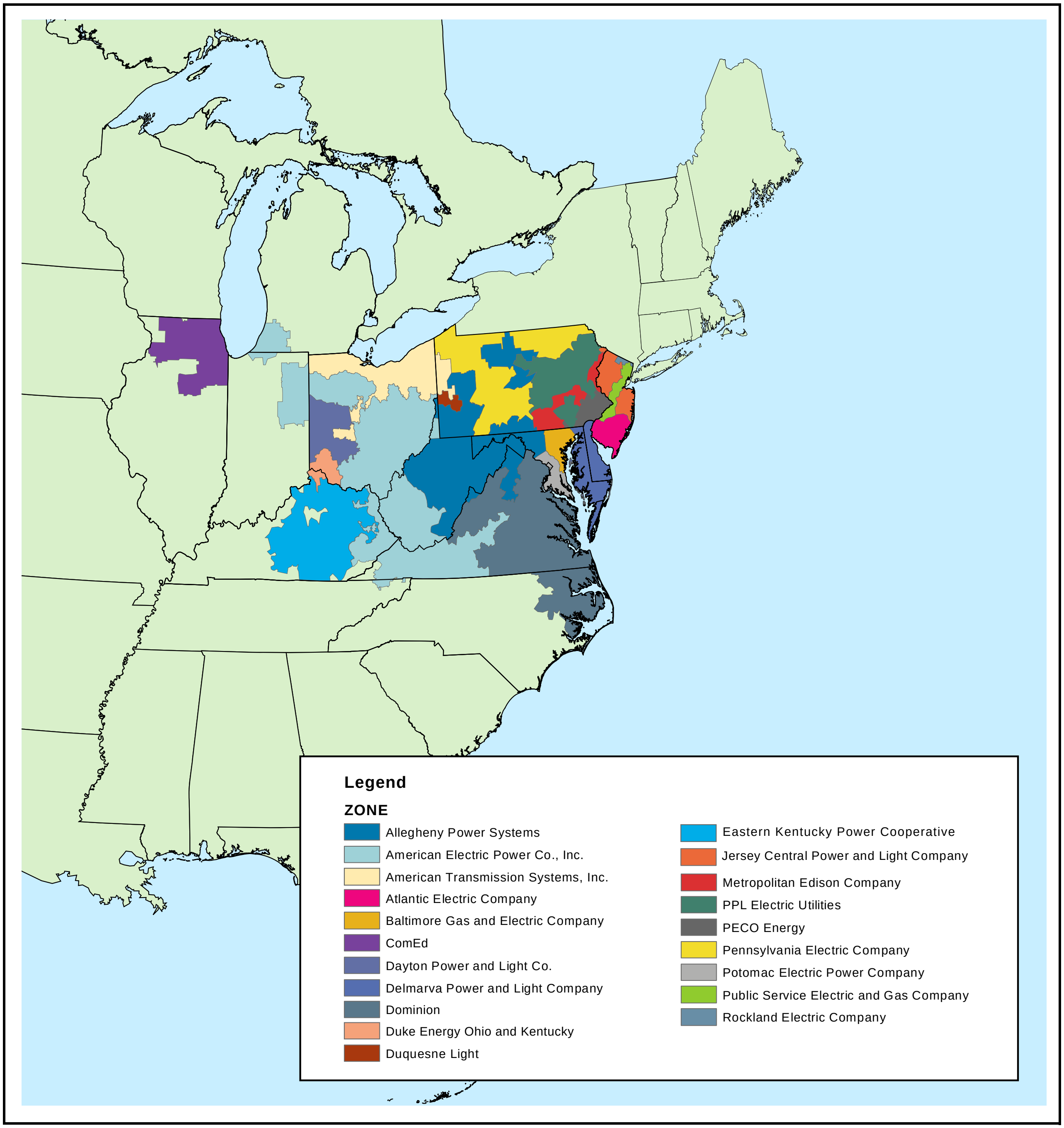
Figure 8.1-2 Deleted

Figure 8.1-3 Map of DVP's Electric Service Territory



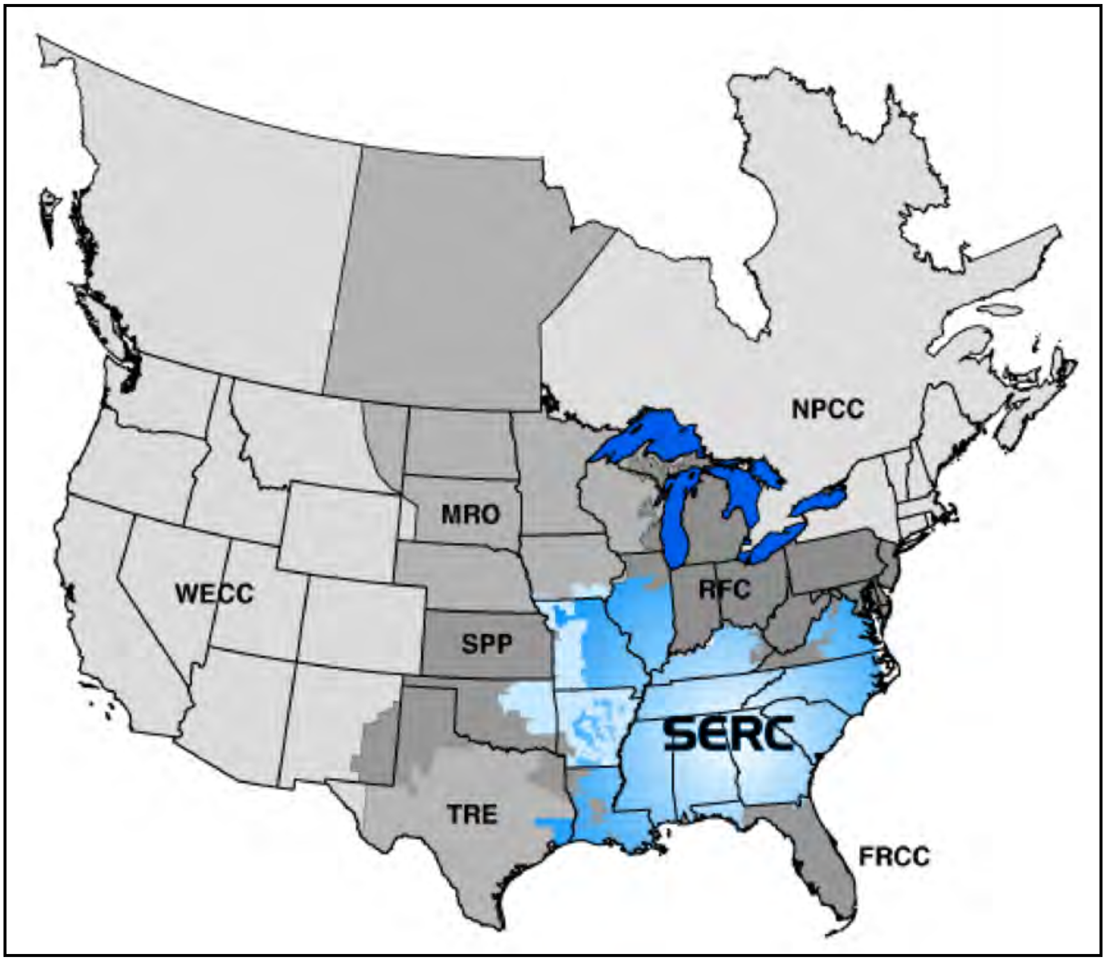
Source: www.dom.com

Figure 8.1-4 PJM RTO Map



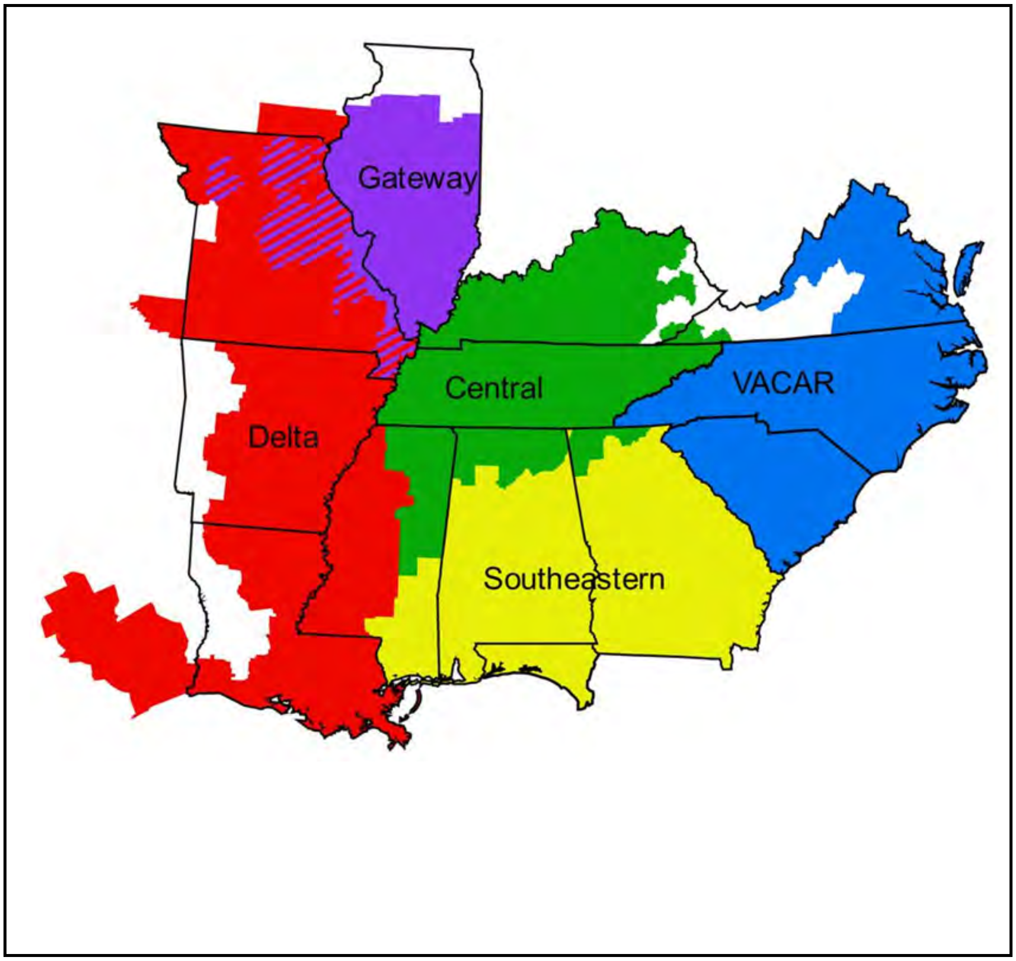
Source: www.pjm.com

Figure 8.1-5 SERC Region



Source: www.serc1.org/Images/USCanMap500x500.gif

Figure 8.1-6 VACAR Sub-Region



Source: http://www.serc1.org

8.2 Power Demand

8.2.1 Power and Energy Requirements

8.2.1.1 Load Forecast

Under the PJM RAA approved by FERC (Reference 1), PJM is responsible for producing a load forecast that is the basis for determining "capacity obligations" for each LSE.[1] Each LSE is required to procure enough capacity, or generation capability, to satisfy its load obligation (with reserve margin). As described below, the PJM load forecast process is systematic, comprehensive, subject to confirmation, and responsive to forecasting uncertainty. Thus, as allowed by NRC's Environmental Standard Review Plan (ESRP), PJM's load forecast is used as the "demand" component of the need for power evaluation.

PJM produces a systematic load forecast every year for a 15-year planning horizon. The 2013 PJM Load Forecast for the Dominion Zone is presented in Table 8.2-1. The forecast represents summer peak load estimates under normal peak weather conditions in the absence of any load reductions due to active load management, voltage reductions or voluntary curtailments. Traditionally, the Dominion Zone is "summer-peaking", i.e., the absolute peak load for the entire year occurs during the summer months. Capacity obligations of each LSE in PJM are determined for the RPM capacity market based on summer peak load. Thus, for reliability planning purposes, the summer peak load forecast is used to evaluate the region's generation adequacy.

According to PJM's 2013 Load Forecast Report (Reference 3), summer peak load growth for the PJM RTO is projected to average 1.3 percent per year over the next 10 years, and 1.2 percent over the next 15 years. Annualized 10-year growth rates for individual zones range from 0.6 percent to 1.9 percent. For the Dominion Zone peak load will increase from 19,619 MW in 2013 to 25,107 MW in 2028, an increase of 5488 MW at a compound average annual growth rate of 1.7 percent. PJM predicts that demand growth in the Dominion Zone will exceed growth rates in all PJM geographic zones except the Pennsylvania Electric Company (PENELEC) zone. For the Dominion Zone, the energy requirement will increase from 97,454 GWh in 2013 to 126,950 GWh in 2028, an increase of 29,496 GWh at a compound average annual growth rate of 1.8 percent. PJM predicts that demand in the Dominion Zone will grow at the second fastest rate in all of the PJM zones.

8.2.1.2 PJM Load Forecast

The PJM demand forecast satisfies the NRC's evaluation criteria of being: 1) systematic; 2) comprehensive; 3) subject to confirmation; 4) and responsive to forecast uncertainty. The basis of this assessment is presented below.

1. Under this RAA, PJM is authorized to guide the reliability planning process in accordance with the reliability principles and standards of other organizations such as the NERC.

8.2.1.2.1 Systematic Process

PJM has a systematic process for load forecasting. The forecast was developed using accepted techniques and employs a wide range of explanatory variables. The PJM load forecasts are based on a multiple variable Ordinary Least Squares regression using economic and calendar variables for each of the 26 LDAs in PJM. Manual 19 provides an overview of the load forecasting process (Reference 2):

> The PJM Load Forecast Model produces 15-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, load deliverability area and the RTO. The model uses anticipated economic growth and historical weather patterns to estimate growth in peak load and energy use. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. Net energy forecasts are used in reporting requirements of FERC and NERC, and for market efficiency studies.

The regressions are specified using zonal metered load data which are adjusted to account for estimated load reductions for recognized demand management efforts. The actual loads used in the regressions are the maximum value for each day, adjusted to reflect unrestricted (before the impact of load management) loads. Calendar effects are then captured by specifying the days of the week, month of the year, holidays, hours of daylight and Daylight Savings Time. Holiday seasonal lighting load is reflected using a trend variable. Weather is reflected in the models as Temperature-Humidity Index and heating and cooling degree-days.[1] Measures of economic and demographic activity are included in the forecast model, representing total U.S., state, or metropolitan areas, depending upon their predictive value. The original economic model specification was based on the U.S. Gross Domestic Product. This specification was updated to reflect Gross State Product and Gross Metropolitan Area Product (Richmond, Virginia Beach and Roanoke for the Dominion Zone model) for Metropolitan Statistical Areas. PJM's Manual 19 provides a detailed description of the load forecasting methodology.

To reflect the variability of weather conditions, for each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily

1. THI = DB - 0.55 * (1 – HUM) * (DB – 58)
Where: THI = Temperature humidity index;
DB = Dry bulb temperature (°F);
HUM = Relative Humidity (where 100% = 1).
THI readings are divided into separate morning, afternoon, evening, and night effects, as well as weekends.

NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. The median values are used as the base (50/50) forecast.

8.2.1.2.2 **Comprehensive**

PJM evaluated a comprehensive set of model parameters and model specifications. The PJM NCP model specification consists of over 50 independent variables which were reviewed above. In PJM's forecasting approach, while the parameter estimates do not vary by month, they do vary across the 20 electric distribution company zones.

A range of different model specifications were evaluated and the preferred specification selected based on its superior performance according to accepted statistical techniques. Specifically, the preferred model specification was chosen based on model backcasting performance after reviewing several alternative specifications. The PJM Load/Energy Forecasting Model White Paper (White Paper) serves as documentation of the implemented peak and energy forecast models as well as other methods and specifications that were tested, but not adopted.

8.2.1.2.3 **Subject to Confirmation**

The PJM load forecast and the forecast results are subject to confirmation by multiple parties. The load forecast is a critical element of the process that is used to establish the capacity obligations of each LSE, which represent significant financial obligations. Thus, the load forecast receives considerable scrutiny from PJM members to ensure that it represents a reliable estimate of future peak loads and basis upon which to evaluate future capacity requirements. The load forecast must meet the forecasting standards of the Reliability Assurance Agreement and PJM Manual 19: Load Data Systems. The Load Analysis Subcommittee (LAS) is organized as a member oversight group that monitors each load forecast produced by PJM.

Under PJM Manual 19, the PJM Load Forecast is reviewed by the LAS, and presented to the Planning Committee for endorsement. Final approval is received from the PJM Board of Managers. A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part of or all the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee. The LAS is comprised of representatives from electrical distribution companies that are members of PJM.

In 2006, PJM load forecast was independently confirmed by the Brattle Group, who were engaged by PJM to provide an independent assessment of PJM's load forecast. (Reference 3) PJM was prompted to conduct this independent evaluation of the model because, among other issues, the 2006 peak load forecast understated the actual peak by 9.36 percent. Weather conditions for the summer 2006 peak were extreme and when the PJM load forecast was re-simulated using those actual weather and economic conditions, the forecast error was only 0.7 percent. The Brattle Group concluded that "the model is doing a good job of forecasting peak demand and the main source of error is weather." (Reference 4)

Additionally, Itron was retained by PJM in 2011 to enhance the accuracy of the existing model by including an index variable. The index variable was developed to remove forecast swings associated with variability in a single economic variable (previously GMP). The index includes other demographic variables that are more stationary and also weights class level sales. The result is expected to be a more consistent forecast from year to year.

8.2.1.2.4 Responsive to Forecast Uncertainty

The predictive capability of the PJM load forecast for the Dominion Zone is indicated by its adjusted R-Squared of 0.961, indicating the over 96 percent of the dependent variable's (i.e., load) variance from the mean is explained by the regression's independent variables and specified parameter estimates. (Reference 3)

The Brattle Group review of the peak demand forecast methodology indicates that the primary source of forecast error and uncertainty are weather conditions. PJM addressed the forecast uncertainty associated with weather through the use of a Monte Carlo simulation based on actual weather conditions. As such the forecast methodology and forecast results adequately account for forecast uncertainty.

8.2.2 Factors Affecting Growth of Demand

This section reviews the factors that affect growth in power demand in the Dominion Zone, including a discussion of the potential impacts of demand side management (DSM) programs on load growth in the Dominion Zone.

8.2.2.1 Economic and Demographic Trends

Section 8.2.1.2 discusses inputs to PJM's load forecast model, which include factors that affect load growth. Specifically, in the PJM load forecast model, calendar effects are captured by specifying the days of the week, month of the year, holidays, hours of daylight and Daylight Savings Time. Holiday seasonal lighting load is reflected using a trend variable. Weather is reflected in the models as Temperature-Humidity Index and heating and cooling degree-days. PJM's Manual 19 provides a detailed description of load forecasting methodology. Measures of economic and demographic activity are included in the forecast model, representing total U.S., state, or metropolitan areas, depending upon their predictive value. The original economic model specification was based on the U.S. Gross Domestic Product. This specification was updated to reflect Gross State Product and Gross Metropolitan Area Product (Richmond, Virginia Beach and Roanoke for the Dominion Zone model) for Metropolitan Statistical Areas. See Figure 8.2-1. (Reference 6)

According to PJM's 2013 Load Forecast Report, the summer peak load for the Dominion Zone will increase from 19,619 MW in 2013 to 23,558 MW in 2023, an increase of 3,939 MW at a compound annual growth rate of 1.8 percent. (Reference 3)

PJM has also recognized the significant economic growth potential in Virginia, stating in their Load Forecast Report from January 2013 (Reference 3):

> The southernmost metro areas are expected to be among the fastest growing in the PJM service territory…Virginia metro areas, including Lynchburg and Richmond, as well as Wilmington DE and Bowling Green, KY, are expected to lead with average annual GDP growth of 2.4 percent or more. Aside from favorable demographics, these metro areas will be driven by highly educated labor forces, productivity growth, and relatively low costs.

As discussed previously in Section 8.1.3, DVP estimates the population growth in the counties in its Virginia and North Carolina service territories since 2007 at about 1.2 percent–1.9 percent per annum and 0.1 percent–4.0 percent per annum, respectively. DVP expects significant growth in baseload requirements through new customer additions, which DVP estimates at approximately 35,000 to 40,000 new customer connections each year and data center growth of 455 MWs from 2013 to 2017. (Reference 5)

8.2.2.2 Energy Efficiency, Conservation and DSM

Electricity demand can also be influenced by DSM programs which are essentially interventions in the market to promote the adoption of more efficient end-uses and to change consumer behavior. This section evaluates the potential impact of such programs on demand growth. Because this analysis is for Unit 3, which would provide baseload power, the focus of the impact of DSM programs is on the impact of such DSM programs on energy requirements, rather than peak demand. In the context of DSM program design, the analysis of the effects is on conservation and energy efficiency programs that are targeted at reducing overall energy requirements rather than demand management programs that are focused on reducing peak demand.

8.2.2.2.1 Current DSM Programs in PJM

PJM has several programs that offer incentives to customers to reduce consumption during peak demand. For example, PJM's Emergency Load Response Program (Reference 8) is designed to encourage customers to reduce load during an emergency event in exchange for compensation from PJM. In addition, the Economic Load Response Program is designed to encourage customers to reduce load when Locational Marginal Prices are high, in exchange for compensation from PJM. These programs are established programs that have been in place since 2002. According to PJM, more than 6000 commercial and industrial facilities (with demand greater than 100 kW) and 45,000 small commercial and residential customers participate in demand response programs offered by PJM. (Reference 7) These programs focus on reducing peak demand and will have virtually no impact on baseload requirements.

8.2.2.2.2 Current DSM Programs in DVP's Service Territory

DVP offers several tariff-based DSM options for both residential and non-residential customers. DVP offers new residences in North Carolina that meet the Energy Star Home (ESH) Plus

Standards for energy efficiency a 5 percent conservation rate discount through its ESH Plus program. DVP also offers Time-of-Usage rate schedules to North Carolina residential customers through Schedule 1P and Schedule 1T and to Virginia residential customers through Schedule 1S and Schedule 1T. (Reference 12, Chapter 3.2) Examples of non-residential tariff-based DSM programs include the Schedule 10 – Large General Service, (Reference 10) which is designed to promote energy conservation on peak days through pricing. This schedule is applicable to customers in both Virginia and North Carolina service territories electing to receive 500 kW or more of Electricity Supply Service and Electric Delivery Service from the Company. For larger customers in North Carolina, with annual average demand of 5000 kW or more, DVP offers the Schedule 6VP - Large General Service, by which a customer's loads are categorized as baseload and peak load, with the prices applicable to peak loads varying by day according to day type. (Reference 12, Chapter 3.2) In addition, for up to 150 hours per year, a Capacity Surcharge rate is applicable to both the base and peak loads. Dominion Virginia Power notifies customers taking service under this schedule to curtail consumption during hours when peak loads are expected to be high, most often during the summer months. During the past two years, customer curtailments reduced load by an estimated 20–22 MW.

In addition to the tariff-based DSM options mentioned above, DVP also offers DSM education programs, which are designed to educate customers and promote energy efficiency and/or conservation. With the exception of education programs, which are focused on capital improvements, the typical DSM programs are designed to reduce consumption during times of peak demand and focus on reliability.

8.2.2.2.3 **Virginia DSM Programs**

As discussed in Section 8.1.3.1, Legislation was recently passed in Virginia that provides for investor-owned electric utilities to meet native load obligations. This Legislation also establishes a goal for the year 2022 of "reducing the consumption of electric energy by retail customers" in Virginia by ten percent of the electric energy consumed by retail customers in 2006. Furthermore, it directed the Virginia SCC to conduct a proceeding to:

> (i) determine whether the ten percent electric energy consumption reduction goal can be achieved cost-effectively through the operation of such programs, and if not, determine the appropriate goal for the year 2022 relative to base year of 2006; (ii) identify the mix of programs that should be implemented in the Commonwealth to cost-effectively achieve the defined electric energy consumption reduction goal by 2022, including but not limited to demand side management, conservation, energy efficiency, real time pricing and consumer education; (iii) develop a plan for the development and implementation of recommended programs, with incentives and alternative means of compliance to achieve such goals, (iv) determine the entity or entities that could most efficiently deploy and administer various

elements of the plan, and (v) estimate the cost of attaining the energy consumption reduction goal. (Reference 9)

The Legislation indicated that these programs may include activities by electric utilities, public or private organizations, or both electric utilities and public or private organizations. The Virginia SCC submitted its findings and recommendations to the Governor and General Assembly in December 2007. In response to this directive by the General Assembly, the Virginia SCC staff and interested parties (including DVP) worked to develop a long-term energy conservation plan (Reference 11) for Virginia.[1]

In July 2007, DVP announced that it had formed a conservation group "to encourage a renewed customer interest in energy efficiency." (Reference 14) The conservation "group will explore new technologies and techniques for residential and business customers to reduce their impact on the environment and help them reduce their demand for electricity."[2] DVP also has identified pilot programs, which are summarized below, to gauge customer interest in and response to certain conservation, energy efficiency, education, demand response, and load management initiatives in Virginia.

Currently, in the Company's Virginia service territory, there are three active Residential DSM Programs approved by the Virginia State Corporation Commission (SCC). These include the Air Conditioner Cycling, Low Income, and Residential Bundle Programs, which is comprised of four programs: Home Energy Check-Up, Duct Testing & Sealing, Heat Pump Tune-Up and Heat Pump Upgrade Programs. In addition, there are three active SCC approved DSM Commercial Programs in Virginia. These include the Commercial Energy Audit, Distributed Generation, and Commercial Duct Testing & Sealing Programs. (Reference 12)

8.2.2.2.4 DVP's Pilot DSM Programs

On September 18, 2007, the Company filed with the SCC for approval of nine conservation, energy efficiency, education, demand response, and load management Pilots. The SCC issued a Final Order on January 17, 2008, that approved the Pilots finding that they were necessary to gather information to help the Commonwealth determine methods to achieve the legislative goal affirmed by the Virginia Energy Plan of reducing energy demand by 10 percent (using 2006 as the base year) by 2022, an approximate 6,170 gigawatt-hour (GWh) reduction. The Pilots were designed not only to reduce sales and peak demand, but to gain valuable operational information and data on customer usage and customer acceptance of DSM programs. The nine approved Pilots included:

1. Direct Load Control - Outdoor Air-Conditioning Control Device Pilot

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1. This long-term energy conservation plan is a separate procedure from the development of the Virginia Energy Plan discussed earlier, which was released September 12, 2007, through the Commonwealth of Virginia Department of Mines, Minerals and Energy (see Section 8.2.2.2.5).
2. Ibid.

2. Programmable Thermostats - Indoor Air-Conditioning Control Device Pilot
3. Programmable Thermostats with Advanced Metering Infrastructure and Critical Peak Pricing Pilot
4. Standard Residential In-Home Energy Audits Pilot
5. ENERGY STAR® Qualified Homes Energy Audits Pilot
6. Energy Efficiency Welcome Kits Pilot
7. PowerCost™ Monitor Pilot
8. Small Commercial On-Site Energy Audits Pilot
9. Distributed Generation ("DG") Pilot Program

In March 2009, the Company filed with the SCC its Final Quarterly Report on the status of the Pilots (Case No. PUE-2007-00089). Since that SCC filing, the Company has filed four follow-up or quarterly reports regarding the status of its Pilots. The Company ended its DG Pilot since its request for approval of the Commercial DG Program was approved by the SCC in Case No. PUE-2011-00093.

The Company is also implementing an Advanced Metering Infrastructure Demonstration.

8.2.2.2.5 **Virginia Target DSM Goals**

As previously noted, the Legislation set the goal to reduce 2022 electric use by 10 percent of 2006 retail consumption through a mix of conservation, energy efficiency, load management, and DSM programs. This same goal was considered by the ten-year comprehensive Virginia Energy Plan (Virginia Energy Plan),[1] issued by the Commonwealth of Virginia Department of Mines, Minerals and Energy on September 12, 2007. The Virginia Energy Plan refers to calculations based on studies in other states that show that Virginia, with a concerted investment in energy efficiency and conservation activities, has an achievable cost-effective electric energy reduction potential of 14 percent over the next ten years. The achievable cost-effective potential is defined as "the potential for a realistic penetration of energy-efficient measures based on a cost-effectiveness evaluation. High levels of support are required, but measured results should exceed associated program costs."[2] The Virginia Energy Plan acknowledges that meeting the achievable cost-effective potential of 14 percent would require a combination of government, utility, non-profit, industry, and business efforts. The plan ultimately calls for a 10 percent reduction goal, which is consistent with the Legislation target, to provide a measure of conservatism. The Virginia Energy Plan acknowledges that Virginia has no established funding source for energy-efficiency and

1. Senate Bill 262 (2006), Virginia Energy Plan Va. Code sec. 67-100 et. seq. (Reference 14).
2. Ibid at 63.

conservation programs and that most states with a successful history of efficiency programs provide significant funding resources. The plan also acknowledges "substantial up-front investment" would be required to achieve the 10 percent reduction goal and estimates "that utilities and consumers together would have to invest an average of approximately $300 million per year over the fifteen-year life of the program ($100 to $120 million by electric utilities, matched by $180 to $200 million by consumers)."[1]

8.2.2.2.6 **Challenges to Adoption of Energy Conservation Measures**

Experience reveals that while a DSM measure may offer lower life cycle costs, capital improvements are generally not implemented by residential, commercial, and industrial consumers, because of long payback periods. Large government complexes are the exception, because they are more willing to accept payback periods of up to 20 years or longer; however, the majority of those opportunities have been explored and implemented, where they meet the requirements of the government programs. As such, there is little opportunity to increase participation in capital intensive DSM programs until the cost of power increases significantly to shorten expected payback periods. An analyst presentation on DSM portfolio development for the City of Tallahassee estimated DSM market penetration for various payback periods. (Reference 13) As shown in Figure 8.2-2, payback periods accepted by customers typically range from 1 to 3 years. This period could be significantly shorter for large industrial customers. The Company utilizes ICF International, Inc. (ICF) to assist in developing its DSM Portfolio and uses a similar payback acceptance curve in its development of DSM Programs.

In addition to long payback periods, many consumers do not implement higher efficiency measures because of:

1. a higher first cost (i.e., initial capital cost);
2. limited capital availability for such higher efficiency measures (e.g., for institutional customers such as governments, budgeting processes make it difficult to purchase replacement equipment even when the electricity cost savings can justify the investment given capital budget limits;[2]
3. concerns about its performance (i.e., service quality as well as the consumer's ability to realize the promised level of savings);
4. lack of credible or reliable information regarding the new product or service which makes it harder to assess the tradeoff between higher first cost and lower operating costs;[3]

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1. Ibid at 66.
2. Energy users appear to discount future savings at rates well in excess of market rates for borrowing or saving (see Reference 15).

5. the cost and level of effort required to become informed regarding the performance characteristics of the new appliance or service (i.e., high "transaction costs");

6. lack of required support infrastructure (e.g., trade allies) to install and service the more efficient device;

7. split incentives where the party making the efficiency decision based on the initial capital outlay is different than the party that is responsible for paying for its operating costs over the life of the investment;[1] and

8. limited attention paid to decisions to implement (purchase or replace) such a measure given the small role energy plays in the total budget.

Based on the above, there is a risk that the Legislation's 10 percent target for potential energy savings does not adequately reflect the impact of the challenges to the adoption of more efficient appliances or end-use equipment by customers or the need for other initiatives such as potential changes to building codes. Thus, the 10 percent reduction supported by the Legislation and the 14 percent potential savings noted in the Virginia Energy Plan are targets that remain uncertain. Moreover, given that many energy conservation and DSM measures affect peak load demand, these reductions likely would have little, if any, impact on DVP's ever-growing need for additional baseload resources. Even if these conservation and DSM measures are assumed to reduce baseload demand, as shown in Section 8.4.1, Unit 3 is still necessary to meet the growth in baseload demand.

Section 8.2 References

1. PJM Interconnection, LLC, "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," report, January 4, 2013.

2. PJM Interconnection, LLC, "PJM Manual 19: Load Data Systems," Revision 22, report February 28, 2013.

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3. This is characterized by economists as "imperfect information". Another example of imperfect information would be future electricity prices which will determine the value of the energy savings. Behavioral research indicates that when consumers are faced with imperfect information and uncertainty consumers are more reluctant to make decisions. This is critical because many of the DSM measures that produce this savings estimate require consumers to make investment decisions to replace existing appliances with new, more efficient appliances or to purchase a new type of appliance with which they have no experience (e.g., ground source heat pump).

1. This is typical in many real estate transactions where residential builders or commercial real estate developers are most concerned with the construction costs of the facility and where the eventual occupant pays the operating costs. Given that the anticipated electricity bills for the property are typically a minor consideration in the purchase or rental decision, buyers and renters give limited consideration to the relative electricity costs.

3. PJM Interconnection, LLC, “PJM Load Forecast Report,” report, January, 2013.

4. The Brattle Group, “An Evaluation of PJM’s Peak Demand Forecasting Process,” December 5, 2006.

5. Dominion, “Investor and Analyst Meeting Presentation,” March 4, 2013.

6. U.S. Department of Commerce, Bureau of Economic Analysis website, June 2013.

7. PJM Interconnection (PJM) website, “2012 State of the Market Report for PJM,” Section 5: Demand Response, March 14, 2013.

8. PJM Interconnection (PJM), “PJM Emergency Load Response Program” report, October 20, 2011.

9. Virginia Legislature, House Bill 3068, Senate Bill 1416, Acts of Assembly Chapters 888 and 933, 2007.

10. Virginia Electric and Power Company, “Schedule 10, Large General Service,” report, November 2, 2012.

11. Commonwealth of Virginia, Department of Mines, Minerals and Energy website, “2010 The Virginia Energy Plan,” July 1, 2010.

12. Dominion, “Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan”, August 31, 2012.

13. Gary Brinkworth and Steve Hastie, Presentation to FEC Advisory Group, DSM Portfolio Development, City of Tallahassee Integrated Resource Planning Study, July 27, 2007.

14. Dominion Electric News Release, “Dominion Virginia Power Announces Energy Conservation Efforts,” July 13, 2007.

15. Marbek Resource Consultants Ltd. and M.K. Jaccard and Associates, Inc., “Demand Side Management Potential In Canada: Energy Efficiency Study”, May 2006.

Table 8.2-1 Dominion Zone - Summer Peak Loads (MW) and Growth Rates

	MW	Growth %
2013	19,619	1.5
2014	20,154	2.7
2015	20,747	2.9
2016	21,228	2.3
2017	21,604	1.8
2018	21,919	1.5
2019	22,262	1.6
2020	22,614	1.6
2021	22,931	1.4
2022	23,232	1.3
2023	23,558	1.4
2024	23,856	1.3
2025	24,201	1.4
2026	24,518	1.3
2027	24,781	1.1
2028	25,107	1.3
Average Annual Growth Rate (10-Year)		1.8
Average Annual Growth Rate (15-Year)		1.7

Figure 8.2-1 Industrial Structure of the Gross State Product, 2011

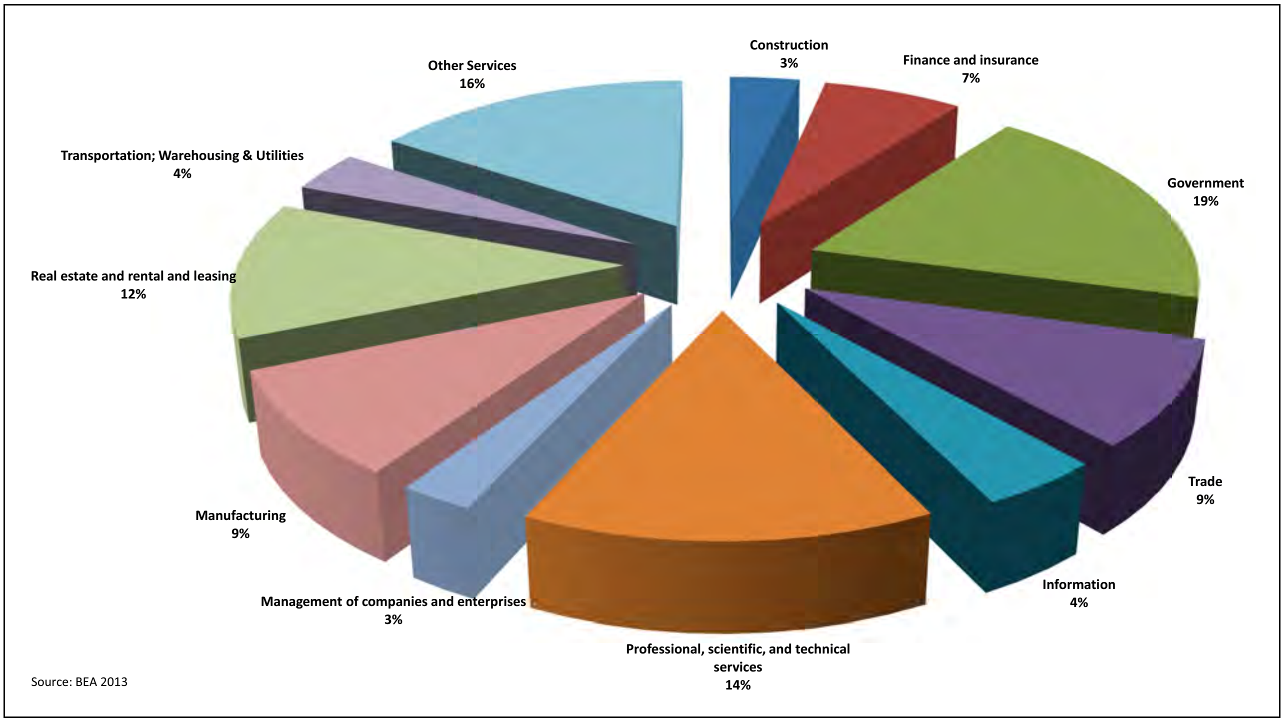
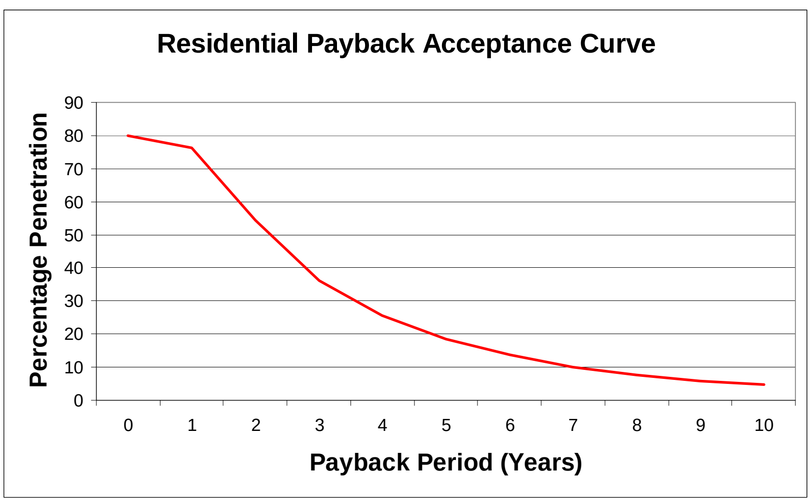


Figure 8.2-2 Residential Payback Acceptance Curve



Source: Gary Brinkworth and Steve Hastie, Presentation to FEC Advisory Group, DSM Portfolio Development, City of Tallahassee Integrated Resource Planning Study, July 27, 2007

8.3 Power Supply

This section reviews the present and planned generating capability within the Dominion Zone and the present and planned purchases and sales of power and energy.

8.3.1 Existing and Planned Generating Capacity in PJM Dominion Zone

8.3.1.1 Existing Generating Capacity

PJM periodically publishes information regarding generating unit ratings most recently in its "2010 PJM EIA-411 Report." (Reference 8) These reports contain PJM's published assessment of each utility system's installed capacity. PJM uses the term "rating" synonymously with installed capacity, and these values are the basis for the following regional capability analysis.

The generating units located within the Dominion Zone currently total summer and winter capacity of 23,993 MW and 24,819 MW, respectively. (Reference 8) As shown in Figure 8.3-1, oil and/or gas-fired units make up approximately 41 percent, while coal-fired and nuclear units account for approximately 28 percent and 15 percent of summer capacity, respectively.

8.3.1.1.1 Baseload, Intermediate, and Peaking Capacity

Each of the different technology types listed in Figure 8.3-1 has different performance characteristics, capital costs, and operation and maintenance costs. The generating units with the least expensive variable costs (e.g., nuclear and coal units), operate almost continuously to meet the minimum level of electricity that is demanded by a system, (i.e., the baseload). While hydro and wind are also used to meet demand, these technology types are considered intermittent capacity resources as their operation capability depends on such factors as water flow and wind speeds, respectively.

For purposes of this analysis, baseload capacity is defined to include units with a capacity factor of 65 percent or greater. This baseload capacity factor assumption is consistent with the baseload definitions assumed by the Edison Electric Institute (EEI) and California Senate Bill 1368. (Reference 2) Baseload capacity includes nuclear, coal, biomass, and hydro units.

During peak demand periods when consumers demand more electricity, the generating units with higher variable fuel costs (typically oil or natural gas) and the operational capability to quickly start are called upon by the PJM RTO to meet the peak load. "Peaking capacity," while expensive to operate, is relatively less expensive to construct. For purposes of this analysis, peak capacity is defined to include units with a capacity factor of 30 percent or less; this definition of a peaking resource is consistent with methods utilized by market participants (e.g., Calpine), and power pool market administrators (e.g., Ontario Independent Electricity System Operator). (Reference 1 and Reference 6) Given the assumed capacity factor ranges for baseload and peaking capacity, it follows that intermediate capacity includes units with a capacity factor that falls within a range of 30 percent to 65 percent. Based on the 2012 IRP, DVP's current and future Combined Cycle units, on average, which have been operating at considerably higher capacity factors than in the past, are projected to operate at capacity factors below 65 percent, thus they should not be considered baseload units.

Figure 8.3-2 is an illustrative representation of the Dominion Zone's 2012 historical load duration curve and its fit against the current installed capacity in the Dominion Zone. While the 65th percentile hour load is not exactly equal to the amount of required installed baseload capacity, it is a reasonable proxy for baseload capacity requirements after reducing capacity supply by assumed availability rates. Figure 8.3-2 includes the installed capacity listed in Figure 8.3-1 adjusted for assumed unit availability rates presented in Table 8.3-1.

As shown in Figure 8.3-2, baseload capacity in the Dominion Zone is composed predominately of nuclear and coal-fired units. Intermediate capacity is composed of gas-fired combined cycle units, while peaking capacity is composed predominantly of pumped storage, oil and gas-fired units.

To estimate the unit availability rates shown above for hydroelectric and nuclear sources, historical state level generation and capacity data published by the EIA were reviewed. As previously noted, nuclear units in Virginia on average operated with a 90 percent capacity factor over the three year period from 2009 to 2011, while hydroelectric units operated with a 20 percent average capacity factor in this timeframe.

Availability rates for all technology types shown in Table 8.3-1 were assumed to be equal to 1 minus the five-year average Equivalent Forced Outage Rate (EFORd) minus Planned Outage Rate as published by NERC in its "2006-2010 Generating Unit Statistical Brochure." (Reference 10)

8.3.1.1.2 **Recently Constructed Generating Capacity**

In 2012, DVP completed VCHEC, which is a 585 MW coal facility located in Virginia City, Virginia. DVP also completed uprates totaling 126 MW to the existing North Anna and Surry power plants, and 31 MW of uprates to Mt. Storm, and 16 MW at Chesterfield Power Station, in addition to combined cycles and combustion turbines that have been added since 2003, which are generally more suitable in the long term as cycling or mid-range resources. As shown in Section 8.4, additional baseload capacity is needed to meet growing baseload requirements in the Dominion Zone.

As shown in Table 8.3-3, 20 generating units have been built and placed into commercial operation within the Dominion Zone since 2003, totaling 3564 MW of summer capacity. These recent capacity additions have been predominantly gas-fired. Specifically, over 99 percent of these recent capacity additions are from gas-fired units of which 40 percent are peaking simple-cycle combustion turbines and 58 percent are combined-cycles.

This recent trend of predominantly gas-fired capacity additions in the Dominion Zone is expected to continue based on analysis of the PJM Generation Interconnection Queue.

8.3.1.2 **Planned Generating Capacity**

One of PJM's primary roles is the oversight of the reliability planning process. (Reference 9) PJM manages incremental generation capacity development through the Generation Interconnection Queue, which is part of a larger RTEP. Developers wishing to provide new incremental generation capacity must file an interconnection request and enter into PJM's queue-based, 3-study interconnection process, which offers developers the flexibility to consider and explore their respective generation interconnection business opportunities. While a developer can withdraw a project from the Generation Interconnection Queue at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. (Reference 14) While not all projects in the Generation Interconnection Queue are expected to be built, the Generation Interconnection Queue does provide an authoritative source for future generation investment trends in the PJM RTO.

Table 8.3-4 lists the individual generation interconnection requests for projects located in the Dominion Zone that are currently active in the PJM Generation Interconnection Queues as of May 2013.

Analysis of the individual generation interconnection requests listed in Table 8.3-4 reveals 27 active generating interconnection requests in the Dominion Zone totaling 5,896 MW from primarily natural gas fuel sources. Again, not all of these projects currently under-study are expected to be built. According to the 2012 PJM Reserve Requirement Study, the commercial probability of a unit coming into service is between 12 and 66 percent. (Reference 17)

Excluding the proposed Unit 3, there are currently only 161 MW of other baseload capacity projects listed in the interconnection queue. Unit 3 is the only baseload capacity project currently listed in the Generation Interconnection Queue for the Dominion Zone that is over 100 MW.

The pumped storage and conventional hydro projects listed in the interconnection queue primarily represent improvements to existing generating facilities, rather than new facilities. (Reference 14)

Figure 8.3-3 shows Wind-Powered Generation in PJM as of 2012. Wind-powered generation projects require geographic areas with favorable wind characteristics such as speed, duration, and frequency of occurrence. See Section 9.2.2.1.1 for a discussion of the feasibility of wind-powered generation projects in the Dominion Zone.

8.3.1.3 **Renewable Portfolio Standards**

Both Virginia and North Carolina have adopted Renewable Portfolio Standards (RPS), but with different goals or requirements and RPS targets as described in more detail below. Based on EIA state-wide generation by fuel source data and EIA's own definition of renewable resources, which may or may not agree with Virginia and North Carolina's RPS definitions for qualifying renewable resources, excluding hydroelectric projects, currently supply about 3.2 percent and 1.4 percent of the net generation produced state-wide in Virginia and North Carolina, respectively. (Reference 5)

While the development of new renewable sources may increase, most new renewable sources alone are unlikely to replace the need for additional baseload generation, because most renewable projects fit into one of the following categories: 1) utility-scale facilities (over 100 MW) such as wind, solar, or hydro that have capacity factors of between 20 percent and 40 percent and are recognized by PJM as being intermittent generation resources, or 2) smaller facilities (<10 MW) with capacity factors greater than 65 percent but are limited by available viable sites and therefore cannot, on their own, meet the projected growth rate for baseload electricity demand in the Dominion Zone. As discussed in Section 9.2.2.1, while DVP plans to undertake all commercially reasonable efforts to meet renewable portfolio standards and emerging state initiatives, renewable resources are not of the scale or type needed to provide power to meet the baseload needs of the Dominion Zone.

Virginia enacted a voluntary renewable energy portfolio goal as part of the 2007 Legislation. Under the RPS goal, investor-owned utilities are encouraged to produce or procure, by 2022, 12 percent of the amount of electricity sold in 2007 (the "base year") from eligible renewable sources, and the Legislation provides for recovery of certain incremental costs by a utility participating in such a program. The following schedule of intermediate RPS goals was adopted. (Reference 3)

- RPS Goal I: 4 percent of base year sales in 2010
- RPS Goal II: Average of 4 percent of base year sales in 2011 through 2015, and 7 percent of base year sales in 2016
- RPS Goal III: Average of 7 percent of base year sales in 2017 through 2021, and 12 percent of base year sales in 2022[1]

North Carolina enacted a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in August 2007 requiring all investor-owned utilities in the state to supply 12.5 percent of 2020 retail electricity sales in the state from eligible renewable energy resources by 2021. The overall target for renewable energy includes technology-specific targets of 0.2 percent solar by 2018, 0.2 percent energy recovery from swine waste by 2018, and 900,000 megawatt-hours (MW-hrs) of electricity derived from poultry waste by 2014. Large hydroelectric units over 10 MW are not considered eligible energy resources in North Carolina. The North Carolina REPS compliance schedule is listed below with each year's percentage requirement referring to the previous year's electricity sales.

- 2010: 0.02 percent solar
- 2012: 3 percent (including 0.07% solar + 0.07 percent swine waste + 170,000 MW-hrs poultry waste)

1. According to Va. Code §56-585.2(A), base year sales are calculated as "Total electric energy sold to Virginia jurisdictional retail customers by a participating utility in calendar year 2007, excluding an amount equivalent to the average of the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants for the calendar years 2004 through 2006.

- 2013: 3 percent (including 0.07% solar + 0.07% swine waste + 700,000 MW-hrs poultry waste)
- 2014: 3 percent (including 0.07% solar + 0.07% swine waste + 900,000 MW-hrs poultry waste)
- 2015: 6 percent (including 0.14% solar + 0.14% swine waste + 900,000 MW-hrs poultry waste)
- 2018: 10 percent (including 0.20% solar + 0.20% swine waste + 900,000 MW-hrs poultry waste)
- 2021: 12.5 percent (including 0.20% solar + 0.20% swine waste + 900,000 MW-hrs poultry waste)

Up until 2021, 25 percent of the REPS requirements may be met through savings due to the implementation of energy efficiency measures. Beginning in calendar year 2021 and each year after, 40 percent of the REPS requirements may be met through savings due to the implementation of energy efficiency measures.

Senate Bill 3 allows electric power suppliers to recover the incremental costs incurred to comply with the REPS requirements and fund research through an annual rider, which is not to exceed the following per-account annual charges:

8.3.2 Purchases and Sales

Based on U.S. EIA data, in 2010, the Commonwealth of Virginia was the second largest importer of electricity in the United States on a total MW-hr basis. Based on the same data, the Commonwealth of Virginia imported the third largest percentage of consumed power of PJM states, with imports meeting approximately 36 percent of Virginia's total state-wide electric consumption. (Reference 4) The District of Columbia, Delaware, Maryland, and New Jersey also rely heavily on imported power and compete with Virginia for available power supplies from West Virginia, Pennsylvania and Illinois. North Carolina is less reliant on imports, but does import approximately 6 percent of its annual energy consumption. (Reference 4)

8.3.2.1 Existing Purchase Agreements

As shown in Table 8.3-7, DVP currently contracts for 1,867 MW of capacity through existing Power Purchase Agreements (PPAs). All 1,867 MW of this capacity comes from generation located within the Dominion Zone, of which 44 percent is from coal-fired baseload capacity. In addition, all 1,867 MW (822 MW is baseload) of this contracted capacity is scheduled to expire by end of 2024.

Relying on the future availability of long-term PPAs from developers of new baseload resources in other regions outside Virginia introduces uncertainty as to capacity and energy supply for DVP. Under the terms of Virginia's recent Legislation, DVP has an obligation to meet the demands of its native-load customers and the Virginia General Assembly has made the policy determination to promote the construction of baseload generation for this purpose. Power project developers may not have energy and capacity available to provide to DVP in the future. There may also be competition for the available long-term baseload PPAs among the other load centers surrounding the Dominion Zone.

In 2012, DVP executed 22,633,479 MW-hrs of power purchases, over 25 percent of its total energy requirements, of which 8,428,351 MW-hrs was contracted through PPAs and the remaining 14,205,128 MW-hrs were purchases from the PJM spot energy market. (Reference 7)

8.3.2.2 Power Sales

As shown in Table 8.3-9, DVP sold 4,217,681 MW-hrs for resale in 2012. The majority of these sales for resale was within the Dominion Zone and was sold specifically to VMEA, NCEMC, and ODEC under purchase agreements with a set pricing schedule, but load-based requirements. These sales were usually met with intermediate and peaking units.

DVP currently has one long-term power sales contract with NCEMC for 150 MW through a combined cycle call option agreement that is due to expire at the end of 2014.

8.3.2.3 Transmission and Additional Constraints on Power Purchases

In addition to concerns of long-term supply assurance, reliance on power imported from other states increases demand on west-to-east transmission capabilities, resulting in heightened vulnerability to transmission-related interruptions.

The Virginia SCC has also expressed concerns regarding congestion in northern Virginia and the Dominion Zone in particular. (Reference 15) The impact of congestion on the Dominion Zone's cost of power is illustrated in Figure 8.3-5, which shows the simple average Day-Ahead Locational Marginal Price (LMP) by PJM zone for the twelve month period ended December 31, 2012.

A review of the 2012 simple average day-ahead zonal LMPs reveals that the Dominion Zone, along with Potomac Electric Power Company (PEPCO), Baltimore Gas and Electric (BGE), and Delmarva Power and Light Company (DPL) zones were the most expensive PJM zones. On average, the Dominion Zone LMP was 4.6 percent higher than the average PJM LMP. Zones to the west (i.e., American Electric Power Co. (AEP), Allegheny Power (APS) and Duquesne Light Company (DUQ)) were less expensive zones compared to the Dominion Zone. The zonal average LMP differentials shown in Figure 8.3-5 are conservative, as these 2012 average LMPs are not load-weighted annual averages.[1]

8.3.3 Potential Retirements

Between September 2002 and April 2013, 15,205 MWs of generator retirements (deactivations) have taken place within PJM, of which 241 MWs were in the Dominion Zone (Reference 17). For the May 2013 through December 2015 period, there have been announced retirements of an additional 11,416 MWs, of which 902 MWs are in the Dominion Zone (Reference 16).

1. The load weighted LMP price is a better indicator of market prices in that the actual costs incurred to serve load will vary with the respective load and price for the varying time intervals. LMPs paid by loads vary hourly (Reference 15).

Section 8.3 References

1. Calpine, "Contractual Portfolio," November 3, 2005.
2. California Senate Bill No. 1368, Chapter 598, Approved by Governor, December 2009.
3. Database of State Incentives for Renewables & Efficiency (DSIRE), website, March 28, 2013.
4. Energy Information Administration website, "State Electricity Profiles 2010", January 27, 2012.
5. Energy Information Administration, "2011 State Energy Profile," February 14, 2013.
6. Independent Electricity Market Operator, "Market Evolution Program (MEP) Breakout Feedback Sessions," report, February 18, 2003.
7. Virginia Electric and Power Company, "FERC Form 1," 2012.
8. PJM Interconnection, LLC, "2010 PJM Load Capacity and Transmission Report," EIA-411 Report, December 28, 2011.
9. PJM Interconnection, LLC website, "About PJM," 2013.
10. NERC website, "2006-2010 Generating Unit Statistical Brochure - Units Reporting Events," November 16, 2011.
11. PJM Interconnection, LLC website, "Hourly Load Data, 2005-2007," from a website database.
12. PJM Interconnection, LLC website, "Future Deactivations (as of 6/5/2013)," from a website database.
13. PJM Interconnection, LLC website, "Generation Interconnection Queue (as of 5/4/2013)," from a website database.
14. PJM Interconnection, LLC, "PJM 2012 Regional Transmission Expansion Plan," February 28, 2013.
15. Virginia State Corporation Commission, "Status Report: Implementation of the Virginia Electric Utility Regulation," September 1, 2012.
16. PJM Interconnection, LLC website, "Generator Deactivations (as of 5/12/2013)," from PJM's website.
17. PJM Interconnection, LLC, "2012 PJM Reserve Requirement Study," October 5, 2012.

Table 8.3-1 Unit Availability Rates by Technology Type

Unit Availability Rates By Technology Type	(EFORd) Forced Outage Rate	Planned Outage Rate	Availability Rate
Hydroelectric	5.39%		95%
Nuclear	2.99%	7.34%	90%
Biomass	7.61%	8.94%	83%
Coal	7.40%	8.73%	84%
Gas Combined Cycle	5.01%	-	95%
Gas/Oil Steam	9.44%	-	91%
Pumped Storage	3.24%	-	97%
Combustion Turbine	9.62%	-	90%
Internal Combustion	15.79%	-	84%

Table 8.3-2 Deleted

Table 8.3-3 New Generating Capacity Additions in the Dominion Zone Since 2010

	Company	Plant Name	Unit	Fuel Type	Type	Net Capability (MW)	On Line Year
1	Old Dominion Electric Coop	Louisa	G12	NG	GT	154	2003
2	Old Dominion Electric Coop	Louisa	G34	NG	GT	154	2003
3	Old Dominion Electric Coop	Louisa	G5	NG	GT	158	2003
4	Virginia Electric & Power Co	Possum Point	G6S	NG	CC	559	2003
5	Industrial Power Generating Company LLC	Chesterfield Landfill	1-48	Landfill gas	IC	14	2004
6	Tenaska Virginia Partners LP	Fluvanna	GS12	NG	CC	920	2004
7	Old Dominion Electric Coop	Marsh Run	CT1	NG	GT	160	2004
8	Old Dominion Electric Coop	Marsh Run	CT2	NG	GT	159	2004
9	Old Dominion Electric Coop	Marsh Run	CT3	NG	GT	162	2004
10	INGENCO Wholesale Power LLC	BRUNSWICK CTY LF	IC	Landfill gas	IC	11	2007
11	WM Renewable Energy LLC	Bethel	IC	Landfill gas	IC	5	2007
12	Virginia Electric & Power Co	Ladysmith	GT3	NG	GT	161	2008
13	INGENCO Wholesale Power LLC	King & Queen County Landfill	IC	Landfill gas	IC	14	2008
14	Ameresco Stafford LLC	Stafford 1	IC	Landfill gas	IC	2	2008
15	Virginia Electric & Power Co	Ladysmith	GT4	NG	GT	160	2009
16	Virginia Electric & Power Co	Ladysmith	GT5	NG	GT	160	2009
17	WM Renewable Energy LLC	Middle Peninsula Landfill	IC	Landfill gas	IC	6	2009
18	WM Renewable Energy LLC	King George Landfill	GT	Landfill gas	GT	12	2010
19	INGENCO Wholesale Power LLC	Henrico County Landfill	IC	Landfill gas	IC	4	2010
20	Virginia Electric & Power Co	Bear Garden	CC	NG	CC	590	2012
					Total	3,564	

Table 8.3-4 Generator Interconnection Requests in the Dominion Zone, 2013

Queue	PJM Substation	MW	MWC	Year	Type	Fuel
T-167	Four Rivers 230kV	287	120	2017	Intermediate/ Peaking	Natural Gas
V2-030	Front Royal 500kV	950	875	2015	Intermediate/ Peaking	Natural Gas
V4-018	Front Royal 500kV	1,425	415	2015	Intermediate/ Peaking	Natural Gas
W1-029	Winfall 230kV	300	39	2015	Intermittent	Wind
W2-022	Pantego 115kV	74	10	2015	Intermittent	Wind
W2-049	Reedy Creek 115kV	47	47	2013	Baseload	Biomass
W3-047	Front Royal 500kV	1,464	60	2015	Intermediate/ Peaking	Natural Gas
W3-066	Shawboro 230kV	300	40	2015	Intermittent	Wind
X1-080	Poe-Suffolk 115kV	135	135	2013	Intermediate/ Peaking	Natural Gas
X1-084	Altavista 115kV	60	60	2013	Baseload	Biomass
X2-060	East Mill 138kV	30	-	2014	Baseload	Biomass
X2-076	Carson-Wake 500kV	1,551	1,376	2016	Intermediate/ Peaking	Natural Gas
X3-032	Poe-Suffolk 115kV	155	20	2013	Intermediate/ Peaking	Natural Gas
X3-076	Loudoun-Meadowbrook 500kV	1,270	412	2015	Intermediate/ Peaking	Natural Gas
X4-039	Pleasant View-Brambleton 230kV	800	750	2015	Intermediate/ Peaking	Natural Gas
Y1-048	Four Rivers 115kV	372	20	2016	Intermediate/ Peaking	Natural Gas
Y1-066	Four Rivers 115kV	182	13	2016	Intermediate/ Peaking	Natural Gas
Y1-068	East Mill 138kV	50	-	2014	Baseload	Biomass
Y1-086	Morgans Corner	20	8	2016	Intermittent	Solar
Y2-001	Gosport	50	40	2013	Baseload	Biomass
Y2-066	Suffolk 34.5kV	9	9	2013	Intermediate/ Peaking	Methane
Y2-074	Hopewell 230kV	401	8	2013	Intermediate/ Peaking	Natural Gas
Y2-076	Clover 230kV	445	14	2014	Baseload	Coal
Y2-077	Hopewell 230kV	401	30	2013	Intermediate/ Peaking	Natural Gas
Y2-097	Brunswick 500kV	1,551	1,376	2018	Intermediate/ Peaking	Natural Gas
Y2-099	Warrenton 34.5kV	2	2	2016	Intermediate/ Peaking	Methane
Y3-031	Riders Creek 115kV	131	17	2016	Intermittent	Wind
Total			5,896			

MWC = capacity component of total energy output of facility MW = total energy output of facility
Source: Analysis of PJM Generation Interconnection Queue as of May 15, 2013.

Table 8.3-5 Summary of Active Generator Interconnection Requests in the Dominion Zone

Fuel Type	MWC	Percent
Natural Gas	5,610	95%
Wind	106	2%
Biomass	147	3%
Methane	11	0.20%
Solar	8	0.10%
Coal	14	0.20%
Oil	0	0.00%
Total	5,896	100%

Table 8.3-6 North Carolina Annual Rider Caps

Customer Class	2008-2011	2012-2014	2015 and thereafter
Residential per account	$10.00	$12.00	$34.00
Commercial per account	$50.00	$150.00	$150.00
Industrial per account	$500.00	$1,000.00	$1,000.00

Table 8.3-7 Summary of DVP's Power Purchase Agreements

PPAs currently held by DVP as of April 2013 but all are scheduled to expire prior to end of 2024

Capacity Type	Summer Capacity (MW)	Percent of Total
Coal	743	40
Coal/Wood	79	4
Baseload Capacity Subtotal	822	44
Gas/Oil	942	50
Hydro	5	0
Solar	5	0
Landfill Gas	9	1
Solid Waste	84	5
Intermittent/Intermediate Capacity Subtotal	1,045	56
Total Capacity	1,867	100

Table 8.3-8 Deleted

Table 8.3-9 Summary of DVP Sales for Resale, 2012

Name of Company or Public Authority	Statistical Classification	Average Monthly Billing Demand (MW)	Average Monthly NCP Demand	Average Monthly CP Demand	MW-hr Sold
Old Dominion Electric Cooperative	Requirements				—
Craig-Botetourt Electric Coop.	Requirements	3	6	5	26,168
Town of Windsor	Requirements	9	9	7	50,055
Virginia Municipal Electric Assoc.	Requirements	292	294	291	1,871,079
Virginia Municipal Electric Assoc.	Requirements				
North Carolina Electric (NCEMC)	Requirements				1,051,101
Pennsylvania-New Jersey-Maryland	Other Service				188,675
Potomic Electric & Power	Other Service				
Old Dominion Electric Cooperative	Long Term				1,030,612
Allegheny	Short Term				
Edison Mission	Short Term				
Energy Connect	Short Term				
Tenaska	Short Term				
Nextera	Short Term				
NRG	Short Term				
PSEG	Short Term				
RRI	Short Term				
Duquesne	Short Term				
First Energy (ATSI)	Short Term				
PPL Energy Plus	Short Term				
Duke Energy Ohio	Short Term				
First Energy Solutions	Short Term				
Subtotal RQ		304	308	303	2,998,403
Subtotal Non-RQ		—	—	—	1,219,288
Total		304	303	303	4,217,691

Notes:

(1) Requirements Service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as or second only to the supplier's service to its own ultimate customers.

Table 8.3-9 Summary of DVP Sales for Resale, 2012

(2) Long-Term Service means five years or longer.

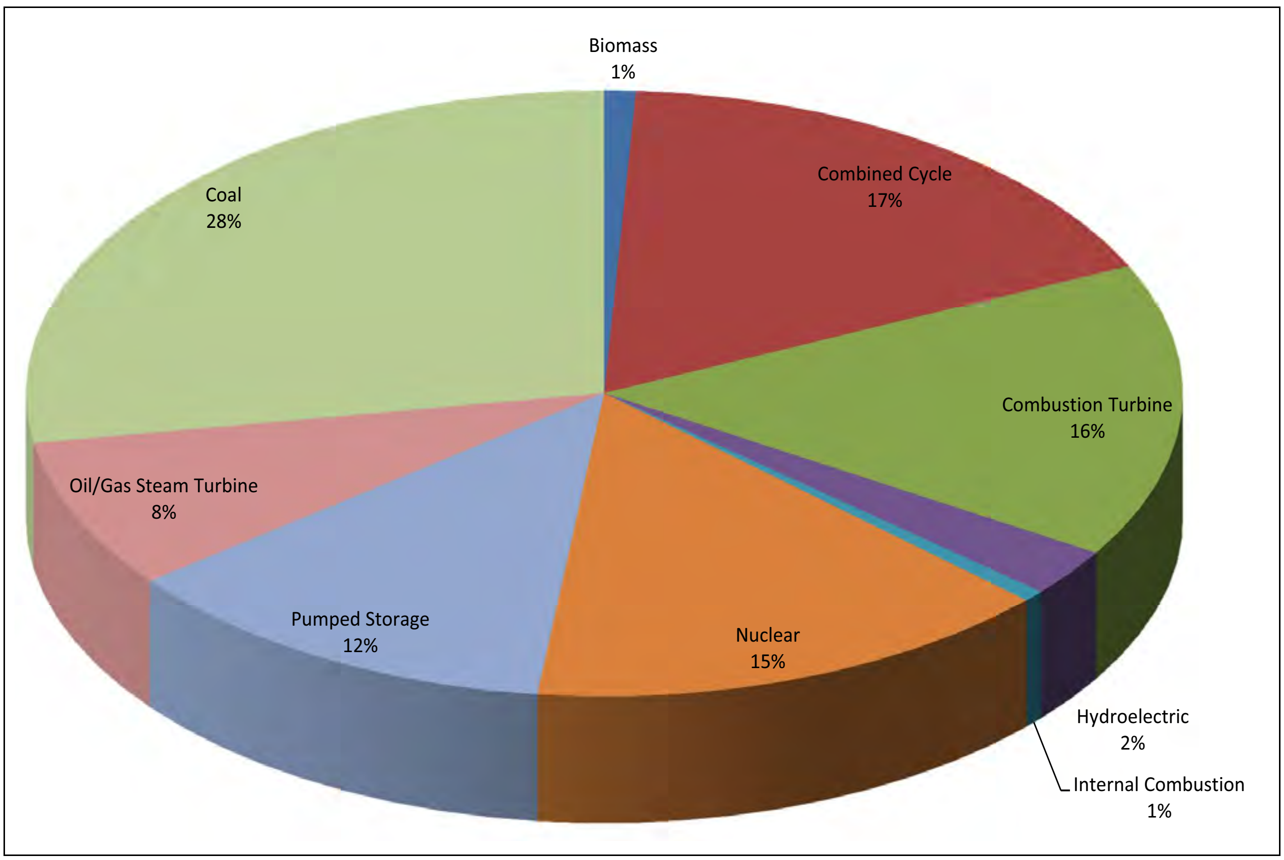
(3) Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month.

(4) Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier’s system reaches its monthly peak.

Source: Virginia Electric and Power Company FERC Form 1, 2012

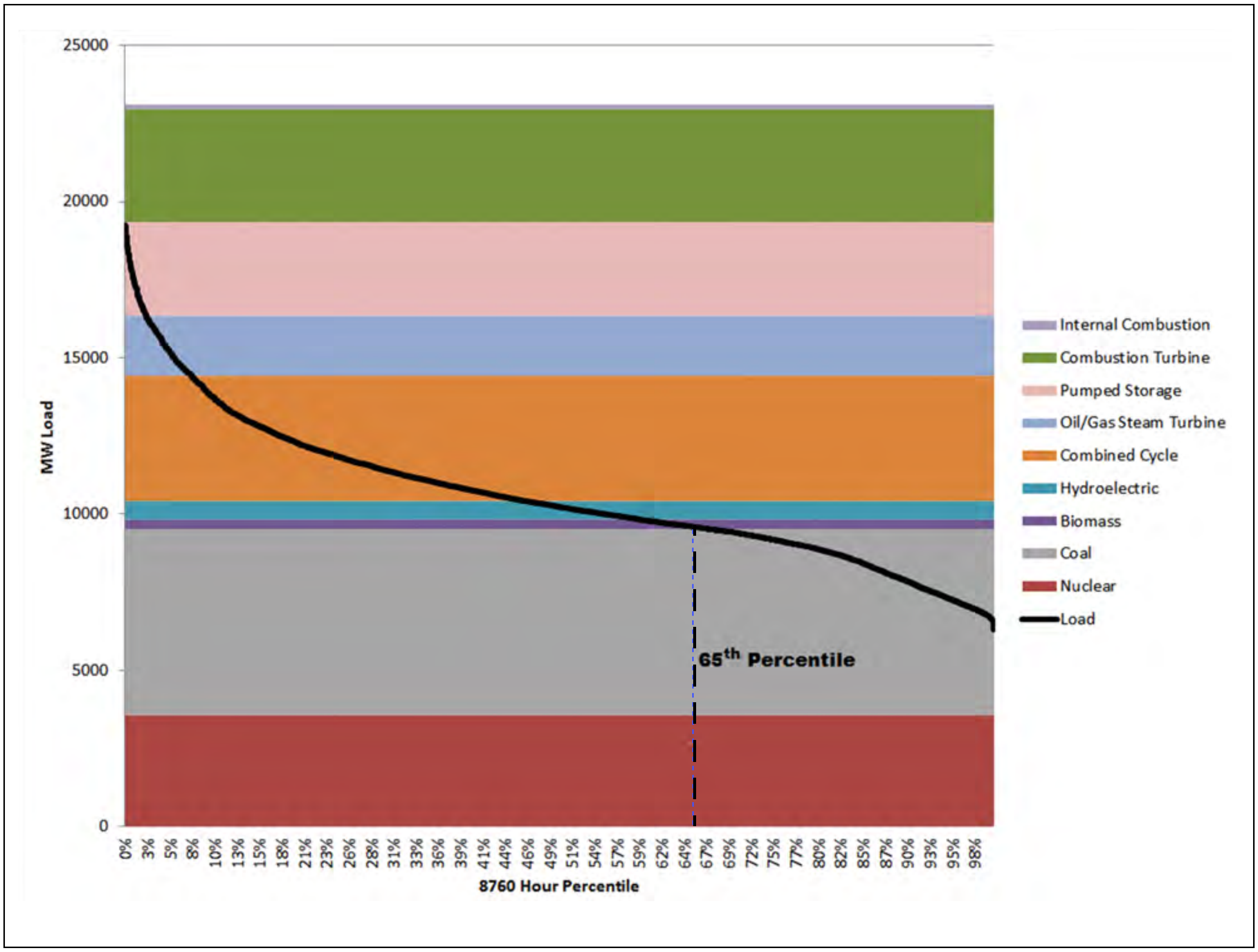
Figure 8.3-1 Dominion Zone – Total Installed Capacity by Technology Type, 2012

Technology Type	Summer Capacity (MW)
Biomass	210
Combined Cycle	4,129
Combustion Turbine	3,780
Hydroelectric	612
Internal Combustion	144
Nuclear	3,563
Pumped Storage	3,003
Oil/Gas Steam Turbine	1,920
Coal	6,633
Total	23,993



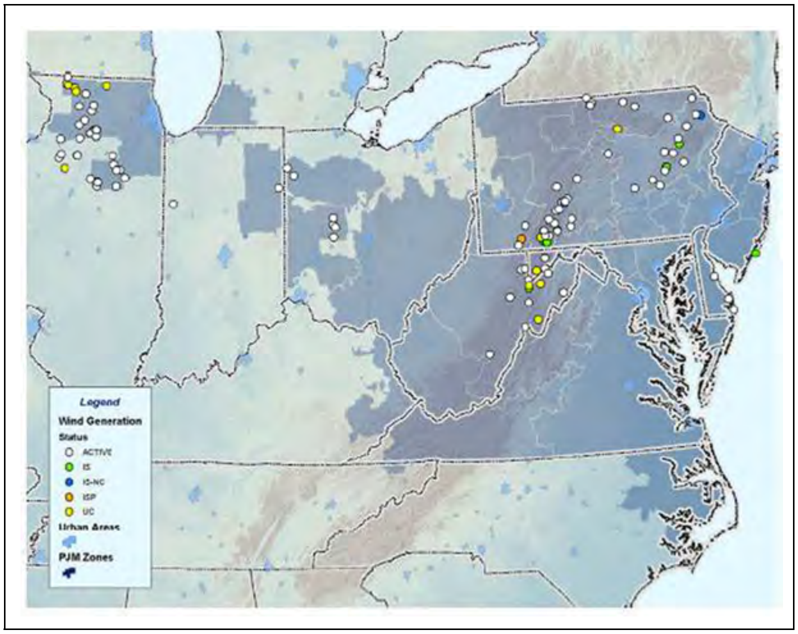
Source: 2012 IRP, EEI, Internal Dominion Analysis

Figure 8.3-2 PJM Dominion Zone 2012 Load Duration Curve



Source: 2012 IRP

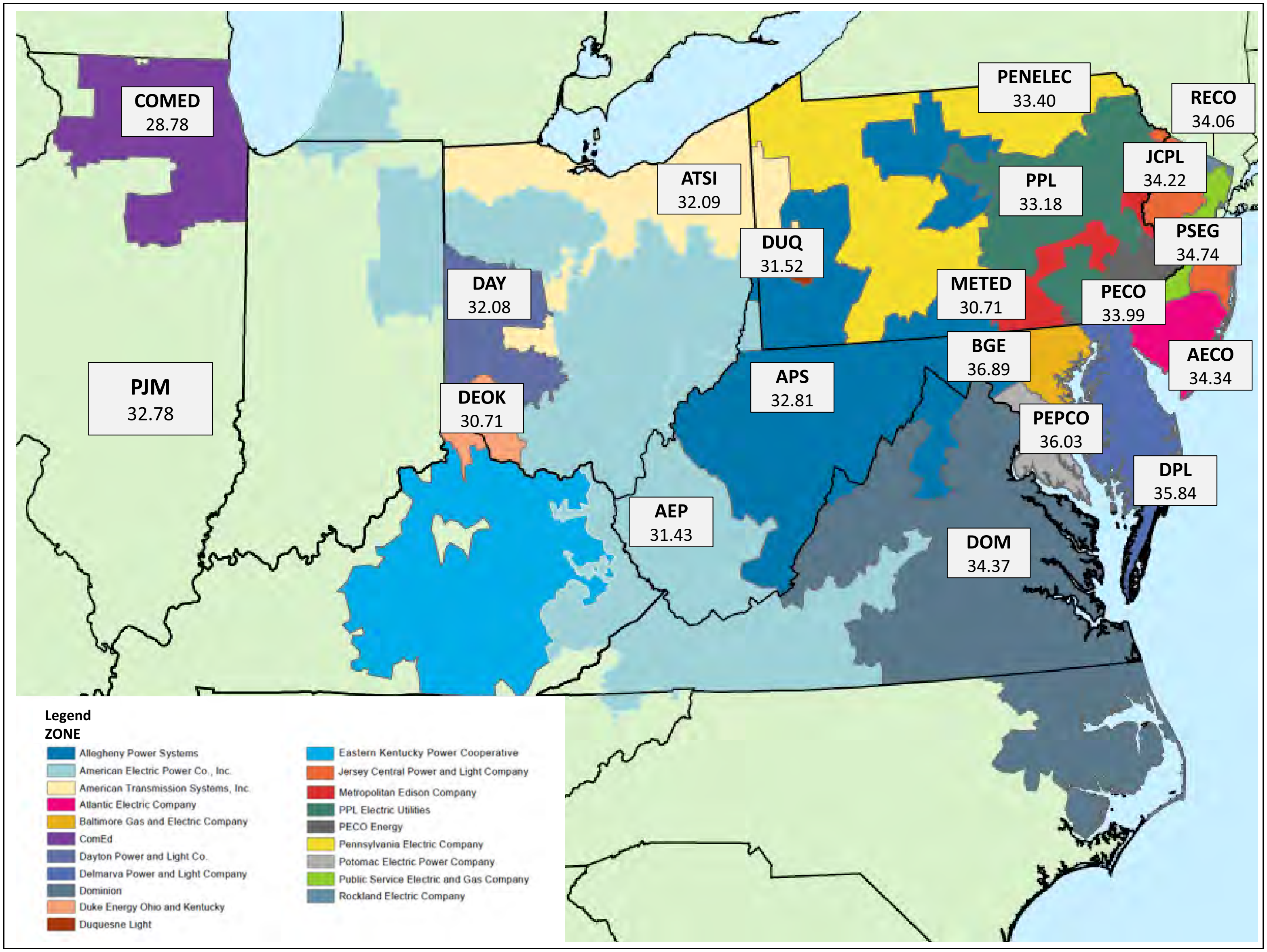
Figure 8.3-3 Clustered Location of Wind-Powered Generation Projects in PJM



Source: PJM 2012 RTEP

Figure 8.3-4 Deleted

Figure 8.3-5 PJM 2012 Zonal Day Ahead LMP



8.4 Assessment of Need for Power

This Section 8.4 identifies the need for power within the Dominion Zone. The Dominion Zone summer peak demand and baseload demand forecasts used in this assessment are discussed in more detail in Section 8.2. Current installed capacity and planned new capacity additions are discussed in Section 8.3.

8.4.1 Need for Baseload Capacity

This section assesses the need for baseload capacity within the Dominion Zone. Unit 3 is proposed and will operate as a baseload facility to help meet this need.

The current baseload demand in the Dominion Zone has been estimated by reviewing 2012 historical PJM integrated hourly loads for the Dominion Zone, sorting the 8760 hourly loads (i.e., 24 hours $\times$ 365 days) in declining order to create the load duration curve shown in Figure 8.3-2, and selecting the 65th percentile hour load equal to 9601 MW as the proxy for 2012 baseload demand. It is assumed that this baseload demand would continue to grow at a compound annual growth rate of 1.8 percent, consistent with PJM's forecasted energy growth rate for the Dominion Zone.

While the 65th percentile hour load is not exactly equal to the amount of required installed baseload capacity, it is a reasonable proxy for baseload capacity requirements after reducing capacity supply by assumed availability rates. For purposes of this analysis, baseload capacity includes capacity from currently operating and planned coal, nuclear, and biomass facilities.[1] These capacity values are reduced by the assumed unit availability rates presented earlier in Table 8.3-1. The derivation of these unit availability rates is discussed in Section 8.3.1. The impact of any potential baseload capacity retirements both in and out of the Dominion Zone is conservatively excluded from the need for baseload capacity analysis.

For the purpose of this analysis, it is assumed that the DSM targets established in the Regulation Act and Virginia Energy Plan will be met in full and it is further assumed that baseload demand will be reduced by those target levels. These conservative assumptions overstate the impact to baseload demand because typical DSM programs serve to reduce peak load demand. The analysis is based on the DSM reduction projected in 2012 IRP. These assumptions are made for both DVP's Virginia and North Carolina service territories in the Dominion Zone.

As shown in Table 8.4-1, the results of the need for baseload capacity analysis indicate that there is currently a need for additional baseload capacity within the Dominion Zone. Unit 3 is not anticipated to be in-service until 2024, by which time the baseload capacity deficiency is projected to be over 2,100 MW, even with the addition of DVP's recently completed VCHEC, and assuming that DSM

1. In the assessment of need for baseload capacity, currently operating and planned combined-cycle units are not considered baseload capacity because they are more generally suitable as cycling or mid-range resources in the long term, particularly during periods of high natural gas prices and price volatility.

levels projected by the 2012 IRP will reduce baseload demand. This additional need for baseload capacity is greater than the potential capacity that would be available from the proposed Unit 3.

8.4.2 Installed Reserve Margins - Peak Demand Supply/Demand Analysis

Projected installed reserve margins for the Dominion Zone are presented in this section, including the proposed projects listed in the PJM Generation Interconnection Queue listed in Table 8.3-4.

Similar to the Need for Baseload Capacity analysis presented above, the impact of any potential retirements both in and out of the Dominion Zone is conservatively excluded from the calculation of installed reserve margins.

The reserve margin calculation (expressed as percentage) is defined as follows:

$$\frac{\text{Estimated Generating Capability + Import Capability – Estimated Peakload Responsibility}}{\text{Estimated Peakload Responsibility}}$$

Table 8.4-2 shows that the projected installed reserve margin, excluding import capacity, falls to 14 percent by 2027, which is below the 15.6 percent installed reserve margin (IRM) planning standard currently approved by PJM.

8.4.3 Summary of Need for Power

As identified in Table 8.4-1, the Dominion Zone has a specific need for new baseload capacity and this need is projected to increase. The baseload capacity supply portfolio in the Dominion Zone is currently out of balance with the need for generation. Development of new baseload capacity has not kept pace with recent growth in energy consumption. Instead, the growth in energy consumption has been met predominantly by the recent development of gas-fired units, which are generally more suitable as cycling or mid-range resources during periods of high gas prices and price volatility, and imported power. In fact, only one new baseload facility has been built in the Dominion Zone since 1996, which is the VCHEC (585 MW), in addition to the completed uprates totaling 126 MW to the existing North Anna and Surry power plants, 31 MW of uprates to Mt Storm, and 16 MW at Chesterfield Power Station. The proposed Unit 3 is the only major facility over 100 MW that does not rely on gas fuel within the Dominion Zone currently under study in the PJM Generation Interconnection Queue. (Reference 5)

Without the additional capacity from the proposed Unit 3 project in 2024, the Dominion Zone will continue to rely heavily on imported power and natural gas for reliability. Reliance on power imported from other states increases demand on west-to-east transmission capabilities, resulting in heightened vulnerability to transmission-related interruptions.

The predominance of new gas-fired generation, planned retirements of aging coal units, and lack of new baseload capacity will decrease fuel diversity, leaving customers more vulnerable to volatility in oil and natural gas prices. According to the PJM market monitor's State of the Market Report, during 2012, coal units provided 42.1 percent, nuclear units 34.6 percent and gas units 18.8 percent of total generation. (Reference 6) Compared to 2011, generation from coal units decreased 7.4 percent, generation from nuclear units increased 4.0 percent, and generation from gas units increased 39.0 percent. Expanding nuclear power within DVP's generation portfolio affords DVP the ability to provide much needed additional fuel diversity and a reliable baseload generation resource with stable operating and fuel cost for its retail customers.

The proposed Unit 3 (approximately 1500 MW) would help alleviate the projected supply imbalance, lessen the region's vulnerability to gas transmission-related interruptions, and manage risks associated with volatility in oil and natural gas prices. Upon commercial operation, Unit 3 will increase the nuclear capacity within the Dominion Zone. When coupled with the recently completed VCHEC, Unit 3 will not only increase diversity of generation technologies for the baseload generation resources in the Dominion Zone, but also enhance the fuel supply diversity of the baseload generation resources.

Section 8.4 References

1. [Deleted]
2. [Deleted]
3. [Deleted]
4. [Deleted]
5. PJM Interconnection, LLC website, "Generation Interconnection Queue (as of 5/15/2013)," from a website database.
6. PJM Interconnection, LLC, "State of Market Report for PJM," March 14, 2013.

Capacity

noted	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR 2013–2028
lour	9,852	10,129	10,439	10,750	10,929	11,099	11,261	11,471	11,630	11,810	11,981	12,176	12,306	12, 467	12,627	12,834	1.8%
	0.6%	0.9%	1.4%	1.9%	2.6%	3.0%	3.4%	3.9%	3.9%	3.8%	3.8%	3.7%	3.7%	3.6%	3.5%	3.6%	
	57	87	141	199	288	337	381	442	448	453	458	450	456	450	445	457	
	9,795	10,042	10,298	10,550	10,641	10,762	10,880	11,028	11,182	11,357	11,523	11,727	11,850	12,018	12,182	12,377	
ility Adjusted	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	10,415	
oility Adjusted																	
	0	0	-856	-856	-856	-856	-856	-856	-856	-856	-856	-856	-856	-856	-856	-856	
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	
	46	46	-810	-810	-810	-810	-810	-810	-810	-810	-810	-810	-810	-810	-810	-810	
	10,461	10,461	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	9,605	
	666	419	-693	-945	-1,036	-1,157	-1,275	-1,423	-1,577	-1,752	-1,918	-2,122	-2,245	-2,413	-2,577	-2,772	

2012 historical actual hourly load data. Assumes baseload demand will increase at same annual energy growth rate as projected in PJM's 2013 Load Forecast Report for Dominion

RP

nstalled Reserve Margin

noted.		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	[1]	19,619	20,154	20,747	21,228	21,604	21,919	22,262	22,614	22,931	23,232	23,558	23,856	24,201	24,518	24,781	25,107
	[2]	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047
		0	-72	-1,049	-1,096	-1,096	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175	-1,175
	[3]	163	166	1,775	3,191	3,270	3,270	4,645	4,649	5,049	5,465	4,375	5,482	5,482	5,482	5,482	5,482
	[4]	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
		27,310	27,241	27,873	29,242	29,322	29,243	30,618	30,621	31,021	31,437	31,447	31,454	31,454	31,454	31,454	31,454
orts)		39%	35%	34%	38%	36%	33%	38%	35%	35%	35%	33%	32%	30%	28%	27%	25%
mports)		23%	20%	19%	23%	21%	19%	24%	22%	22%	22%	20%	19%	17%	16%	14%	13%

ity as of 2013; Source: PJM 2010 EIA-411 Data

eue as of 5/15/2013

rgency transfer limit (CETL). Order on Rehearing and Clarification and Accepting Compliance Filing, Federal Energy Regulatory Commission, Docket No ER05-1410-002 et al., Jun
sed in megawatts, of the Locational Deliverability Area (here, the Dominion Zone).

Chapter 9 Alternatives to the Proposed Action

This chapter assesses the feasibility and potential impact of various alternatives to developing the proposed Unit 3 project while still providing the necessary power to meet projected baseload demand. The alternatives considered and addressed include taking no-action and energy resource alternatives both with and without the development of new generating capacity. This assessment demonstrates that there are few alternatives reasonably capable of meeting DVP's baseload need, and those few alternatives are not environmentally preferable to Unit 3.

While reasonably feasible alternatives are not environmentally preferable to Unit 3, DVP believes that such alternatives are important generation resources that are properly included in a balanced generation portfolio. While DVP believes Unit 3 offers many advantages as part of a baseload generation portfolio, DVP believes that additional, alternative sources will also be required to provide a balanced, fuel-diverse supply to meet DVP's large projected baseload supply obligations.

Section 9.1 provides a discussion of the no-action alternative and its implications on system reliability, fuel diversity and the future price of electricity to consumers. Energy resource alternatives are discussed in Section 9.2.

9.1 No-Action Alternative

The no-action alternative is a scenario under which the NRC denies the application and the proposed Unit 3 is not constructed. Under this scenario, the environmental impacts of constructing and operating Unit 3 would be avoided, but the primary benefit of the project—the needed baseload power—would either remain unfulfilled or have to be provided by an alternative energy resource. The viability and environmental impacts of energy alternatives are addressed in Section 9.2.

Leaving the need unfulfilled is neither desirable nor consistent with DVP's public service obligations. Without the additional capacity from the proposed Unit 3 project or an energy alternative, the Dominion Zone will continue to rely heavily on imported power or as yet unplanned alternative generation, in order to meet its baseload service and reliability obligations. Too great a dependence on power imported from other states is undesirable for Virginia because of the increased demand that it places on west-to-east transmission capabilities, and associated increased vulnerability to transmission-related interruptions. Moreover, imported power may not be a viable alternative for meeting baseload obligations due to competition for baseload capacity resources from surrounding areas (see Section 8.3.2).

As demonstrated in Section 8.4.2, by 2024, projected planned capacity additions will not be sufficient to maintain the 15.6 percent installed reserve margin (IRM) planning standard.[1] Reliability of service to DVP customers could be at risk even sooner than 2024, given the uncertainty

1. Excluding imports.

surrounding whether planned projects will actually be developed and current power supply vulnerability to equipment failure and unplanned shut-downs for maintenance.

As discussed in Section 8.4, there is a current need for additional baseload capacity. Without the development of new baseload capacity, such as Unit 3, the supply portfolio in the Dominion Zone will become increasingly reliant on gas and oil-fired units and will need those resources to operate at higher capacity factors than typical cycling or mid-range resources in order to meet increasing growth in baseload demand. Gas and oil-fired units generally have higher variable operating costs than baseload generation resources. The benefit of adding the nuclear Unit 3 as this low variable cost option to meet baseload demand cannot be attained without NRC action. The mismatch of generation technology type to operational requirement will cause system inefficiencies resulting in increased electricity prices. Moreover, customers will be more vulnerable to oil and natural gas price volatility. While the risk of oil and natural gas price volatility can be hedged in part through long-term contracts, this risk can be further managed by increasing fuel diversity through the development of new nuclear and clean coal capacity. Hence, the development of Unit 3 will help manage risks associated with oil and natural gas price volatility and enable DVP to retain its supply portfolio balance.

9.2 Energy Alternatives

This section describes the environmental impact and viability of various energy sources to serve as alternatives to the baseload generation that would be provided by Unit 3. The alternatives considered and addressed include: power purchases from other generators or the market, reliance on improvement in energy efficiency or demand side management, and other new generating resources from both renewable resources as well as fossil fuels.

Alternatives that do *not* require new generating capacity are assessed in Section 9.2.1. Alternatives that do require new generating capacity are assessed in Section 9.2.2. Certain alternatives reviewed in Section 9.2.2 are eliminated on the basis of being unavailable in the relevant region (i.e., the Dominion Zone) or not commercially feasible; those which may be viable are discussed in Section 9.2.3, which includes an assessment of environmental impact, reliability and general economic competitiveness of each technology.

Consistent with NUREG-1555, (Reference 1) this analysis considers the impact of the integrated PJM market, projected reserve margins, peak loads and load duration curves, transmission inter-tie capability, as well as plant retirements, expected new generation, plant availability and the effect of conservation and load management. Each of these elements, and its impact on the need for power, is addressed in Sections 8.2 and 8.3. Accordingly, Section 9.2 does not repeat those factors but focuses on the ability of alternative sources to meet the baseload need that is projected for the 2024 timeframe, inclusive of the impact of the above-mentioned factors.

9.2.1 Alternatives Not Requiring New Generating Capacity

This section discusses possible methods of supplying the projected demand for baseload energy *without* constructing new generating capacity. The specific options considered include: the viability of purchasing power from other resources, plant reactivation and extended service life, and obviating the need for generation through energy conservation and demand side management measures.

9.2.1.1 Power Purchases

The option of supplying DVP's increasing power requirements to serve native load with power purchases is theoretically possible through purchases from the wholesale market, a specific generating asset or a neighboring utility. However, as discussed in Section 8.1.4, the Dominion Zone is one of 26 Locational Deliverability Areas (LDA) identified by PJM as "constrained areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations." (Reference 2, Schedule 10) In constrained areas, such as the Dominion Zone, baseload capacity for load serving entities (LSEs) must be located within the constrained area or the LSE must enter into a bilateral transaction for capacity into that constrained area.

The option of purchasing energy and capacity from neighboring utilities or resources outside of the Dominion Zone is limited by both transmission import capability as well as other demand centers competing for the same energy and capacity purchases. Significant incremental imports on a firm baseload basis would require major transmission system upgrades or reliance on an already strained transmission system, as discussed in Section 8.3.2. Even with the recently completed Meadow Brook - Loudoun 500 kV line sponsored by DVP and other baseline transmission upgrades included in the PJM RTEP, PJM believes that additional transmission system expansion and new generating sources will still be required to meet expected peak load supply requirements in the Dominion Zone beyond 2015. (Reference 3) Mt Storm-Doubs 500 kV line uprate under construction and proposed Surry-Skiffes Creek 500 kV line, projected to be online by 2015 and 2016, respectively, will enable reliable service in the Dominion Zone. Further, any upgrades to enable a power import comparable to Unit 3 would need to cross multiple utility service territories and may prove cost prohibitive.

DVP has an obligation to meet the demands of its native-load customers, but power project developers may not have energy and capacity available to provide to DVP in the future. (Reference 4) In addition to transmission limits, the availability of energy and capacity from resources outside of Virginia will be reduced by competition from other load centers surrounding the Dominion Zone. Specifically, the District of Columbia, Delaware, Maryland, and New Jersey are also experiencing significant growth and already rely heavily on imports from adjoining regions. Based on EIA generation and consumption data, the District of Columbia imports approximately

98 percent of its annual energy consumption; while Delaware and Maryland import approximately 52 percent and 33 percent, respectively, of their annual energy consumption.

Virginia currently imports approximately 36 percent of its annual energy consumption; North Carolina is less reliant on imports, but does import approximately 6 percent of its annual energy consumption. (Reference 5) The Public Service Commission of Maryland in its "Electric Supply Adequacy Report of 2007," has expressed concerns regarding the uncertainty of electric reliability in Maryland, citing expected demand growth between 1 percent and 2 percent per year, development of little new in-state electric generation, potential de-rates or retirements of fossil-fired generating capacity, and limited transmission capability during peak demand periods. (Reference 6) The projected growth of utilities' energy requirements in the region, combined with the retirements of 1821 MW of capacity in PJM between September 2008 and May 2012, rendered long-term baseload purchases from neighboring utilities unlikely. (Reference 7) By 2011, PJM was projecting that reserve margins in the central portion of Maryland and other eastern regions of PJM would be barely adequate to ensure reliability. (Reference 6) Thus, power purchases cannot be reasonably expected to provide power for a term that would be equivalent to the life of Unit 3.

Based on analysis of the PJM Generation Interconnection Queue as of May 2013, there are currently 5,418 MW (summer rated capacity) under study[1] for the surrounding regions outside the Dominion Zone including in all or parts of VA, NC, WV, PA, OH, NJ, DC and IN.[2] Gas comprises the largest portion with 5,080 MW.

In conclusion, with regard to power purchases as an alternative not requiring new generation, DVP considers the likelihood of resource availability to be low, the potential for additional import delivery through the transmission system to be potentially constrained, and the potential term of such a purchase to be inferior to the Unit 3 option. Accordingly, this alternative is not deemed reasonable or feasible.

9.2.1.2 **Plant Reactivation or Extended Service Life**

DVP has no opportunities to meet its incremental baseload needs through extending the service life of existing plants. There are currently planned plant retirements for Yorktown 1 and 2 and Chesapeake 1,2,3 and 4, totaling 918 MW in the Dominion Zone by 2015

Similarly, there are no viable opportunities for DVP to meet its baseload and reliability needs through re-activating plants. DVP has no plants that are viable candidates for reactivation. Any plant re-activation within the Dominion Zone would require returning to service units that are already retired or mothballed and are likely to need significant uneconomic and capital intensive upgrades to meet current and expected future environmental requirements.

1. Includes projects listed as Active, Under Construction, or Partially In-Service with planned in-service dates after 1/1/2013.
2. As shown in Figure 8.3-5, the average cost of power in these regions is typically lower than in the Dominion Zone.

Even if there were plants with the potential for re-activation or extended service, the plant must first resolve the initial reasons the plant was, or is planned to be, shut down. These reasons typically include failure to be economic in the market or an inability to meet environmental standards; otherwise the plant would not have been retired. Moreover, the plants that have been shutdown, and those that are planned to be retired in the SERC reliability region are, for the most part, fossil fuel stations. Section 9.2.3 examines the environmental impact and feasibility of these technologies and concludes that none of these generating sources are environmentally superior to Unit 3. These technologies also would not provide many of the benefits of Unit 3 discussed in Chapter 8.

9.2.1.3 **Conservation (Energy Efficiency)**

Section 8.2.2.2 details the PJM efforts and the efforts in both Virginia and North Carolina to encourage conservation and energy efficiency. As noted in that section, conservation efforts are not expected to have a significant impact on baseload power needs but rather on peak requirements. In addition, Section 8.4 demonstrates that the growth in baseload need is projected to be over and above the potential effects of the conservation and efficiency targets established by both states and the existing PJM programs. Even if the state targets are met and the PJM programs continue, they will not alter the need for baseload power from Unit 3. Conservation programs have DSM components which are primarily aimed at managing the efficiency gains from peak load, not baseload. If the conservation programs met with extraordinary success, the impact of these programs, at best, could only moderate load growth and slightly defer the need for additional baseload power, but not the need for Unit 3 as shown in Section 8.4. DVP does not consider conservation alone to be a feasible alternative to the proposed Unit 3.

9.2.2 **Alternatives Requiring New Generating Capacity**

This section analyzes possible alternative sources of energy and whether they could reasonably be expected to provide additional generating capacity to commercially serve DVP's baseload power and reliability obligations in a manner that is environmentally preferable to the proposed alternative. Each potential resource is assessed in terms of its potential to provide the required baseload power offered by Unit 3. If a generating source is determined to be viable pursuant to the review in this Section 9.2.2, it is then compared with the proposed project, Unit 3, in Section 9.2.3. This section includes an assessment of currently available technologies as well as those that are projected to be available within the relevant timeframe. Technologies reviewed include fossil fuels, taking into account national policy regarding the use of such fuels, as well as alternative/renewable resources available within the region. Specifically this section covers:

Renewable Fuels:

- Wind
- Geothermal
- Hydropower

- Municipal solid waste and landfill gas
- Biomass/wood waste
- Agriculture-derived biomass (e.g. energy crops)
- Photovoltaic cells and solar thermal

Other Alternatives:

- Integrated gas-fired combined cycle (IGCC)
- Other advanced systems (e.g. fuel cells, synthetic fuels, etc.)

Non Renewable Fuels:

- Petroleum liquids
- Natural gas
- Coal

For the purposes of this Section 9.2.2, DVP assesses renewable resources capable of running exclusively on a renewable fuel. Alternatives involving combinations of facilities are addressed in Section 9.2.2.4.

In performing this evaluation, DVP has used the NRC's Generic Environmental Impact Statement (GEIS) (References 14 and 12) to inform its analysis. The GEIS is useful for the analysis of alternative sources because for License Renewal plants the NRC has determined that evaluation of these alternatives enables the agency to consider the relative environmental consequences of each alternative. To generate the reasonable set of alternatives used in the GEIS, the NRC included commonly known or anticipated generation technologies.

9.2.2.1 **Renewable Fuels**

Generally, renewable resources are not of the scale or type to provide baseload power comparable to the output of Unit 3. Table 9.2-1 depicts the average capacity factors achieved by various renewable resource types nation-wide using data from EIA.

These data indicate that even where viable, most renewable resources are not generally able to provide baseload power or higher capacity outputs equivalent to Unit 3. The non-baseload nature of these resources may be overcome in the future with the development of nano-supercapacitors, energy storage devices such as compressed air systems or large-scale battery systems, and deployment of significant transmission system enhancements. EPRI forecasts that by the mid-2020's nano-capacitor technology may become available for deployment. Large-scale energy storage devices also have not been advanced to the point of economic feasibility. Until these technologies are advanced, non-baseload resources such as solar and wind cannot provide baseload power.[1]

1. Reference 11, pp3–6.

Any comparison of economic or environmental viability between non-baseload or mid-range capacity and baseload capacity would need to account for the diminished average available capacity by proportionately reducing the non-baseload or mid-range capacity ratings by an assumed technology-specific availability rating. However, DVP notes that the resulting average available capacity is not equivalent to the reliability of a baseload unit.

9.2.2.1.1 **Wind**

GEIS Supplement 7 concludes that Virginia is a Class 1 Wind Power region.[1] Figure 9.2-1 shows the annual average wind power in the United States.

Given that wind power is an intermittent resource, in order to compare a wind resource with Unit 3, in terms of average available capacity, one must adjust for the expected capacity factor of that resource. As noted above, EIA data indicate that wind power in the United States has achieved average capacity factors of approximately 23 percent in the 2001–2005 timeframe. The GEIS projects that the average annual capacity factor for wind power will be 29 percent in 2010. (Reference 14) Further, there is poor correlation between wind output and peak demand; in particular, wind tends to be unavailable on a hot summer day when both baseload and peaking resources are most needed. On average, wind resources would require 3.5 times as many MW of installed capacity to provide an average available capacity level equivalent to that from baseload nuclear resources with a capacity factor of 90 percent. However, even after adjusting for average available capacity, this capacity is not equivalent to that of a reliable baseload resource, given that in any point in time, generation can range from zero MW to full capacity.

The GEIS and other public data indicate that wind power requires from 60,000 to 150,000 acres per 1000 MW of capacity depending on location and other siting parameters. (References 14 and 15) In sum, wind power is not a reasonable alternative to provide for the baseload need that would be served by Unit 3 because of wind power's lower capacity factor and land requirements.

9.2.2.1.2 **Geothermal**

GEIS Supplement 7 (References 14 and 15) determined that the average annual capacity factor for geothermal power was 90 percent, making it suitable as a source of baseload generation. The EIA data provided in Table 9.2-1 shows that on average, geothermal resources in the United States achieved capacity factors of approximately 75 percent, in the 2001–2005 timeframe.

While industrial-scale geothermal power generally is available as a baseload resource, it is only available in Virginia or North Carolina for use with ground coupled heat pumps. Figure 8.4 of the GEIS shows that areas with potential for geothermal project development are found in the western United States. Based on 2005 data, the EIA found that there is no industrial-scale geothermal potential in the Dominion Zone. Further, DOE reports that North Carolina and Virginia have only low

1. Reference 12, Section 8.2.5.2.

to moderate temperature resources, and electricity generation from these is not possible. (Reference 16)

Because there is no industrial-scale geothermal potential in the Dominion Zone or even nearby, it is not a reasonable alternative to Unit 3.

9.2.2.1.3 Hydropower

GEIS Supplement 7[1] found that Virginia had 617 MW of undeveloped hydropower resources, which is not enough to equal the output of the proposed project. The GEIS[2] estimates that a 1000 MW hydropower project would require about 1 million acres of land. Based on the project size of Unit 3, approximately 1.5 million acres would have to be flooded in order to be equivalent in capacity. This would create a land use impact of over 2300 square miles.

Hydropower is not a reasonable alternative to the proposed Unit 3 due to the limited availability of identified sites within the Dominion Zone and the amount of land needed.

9.2.2.1.4 Municipal Solid Waste and Landfill Gas-Fired Facilities

The GEIS[3] found that municipal solid waste (MSW) projects could achieve a capacity factor of approximately 85–90 percent, making it a potential source of baseload generation. However, the EIA data provided in Table 9.2-1 shows that on average, landfill gas and MSW resources in the United States achieved more modest capacity factors of approximately 65 percent in the 2001–2005 timeframe.

According to the EIA, in 2005, there were 3055 MW of installed MSW projects throughout the U.S., representing a 7 percent reduction from the 3292 MW installed nationwide in 2001. (Reference 10) Currently there are three MSW facilities, including industrial cogeneration, in the Dominion Zone totaling 207 MW of summer capacity. (References 17 and 18) Site development of MSW projects is limited to landfill sites and is driven by waste management considerations, such as limited availability of sites for landfills due to permitting requirements and zoning restrictions. EPA data indicate that MSW facilities require, on average, 15,000 tons of waste material per year for each MW of capacity. (Reference 19) Accordingly, to provide even 20 percent of the capacity of Unit 3 would mean incinerating an incremental 4.5 million tons of MSW per year, which is over two times the amount of MSW incinerated in Virginia in 2006.[4]

1. Reference 12, Section 8.2.5.4.
2. Reference 14, Section 8.3.4.
3. Reference 14, Section 8.3.7.
4. In 2006, 16.8 million tons of MSW were received in the state of Virginia, including 7.3 million tons of MSW imported from other states. Of this total, 2.1 million tons of MSW was incinerated (Reference 35).

An MSW facility has a footprint similar in size to that of a fossil fuel-fired generator, but also requires landfill space to deposit non-hazardous ash residue. Net landfill space is reduced overall as a result of the combustion process.

The mandatory Renewable Portfolio Standard recently enacted in North Carolina considers landfill gas-fired facilities to be a renewable technology. The Chicago Climate Exchange considers certain landfill gas-fired generation facilities to qualify as emission offset projects.

A report by the National Renewable Energy Laboratory (NREL) presents the current availability of methane from landfills by state. The annual potential amount of this resource is 275,000 tons in Virginia. (Reference 22) Given the dispersed nature of this energy source and the relatively small amount, landfill gas generating facilities could only serve a small portion of an overall energy portfolio.

Due to low generation outputs, MSW and landfill gas are not reasonable alternatives to Unit 3 as potential baseload resources.

9.2.2.1.5 Biomass (Wood), Wood Waste

Wood-burning projects can have capacity factors competitive with traditional baseload sources of generation, although the EIA data provided in Table 9.2-1 shows that on average wood waste resources in the United States achieved capacity factors below 20 percent, in the 2001 – 2005 timeframe, with other biomass resources averaging 36 percent capacity factor.

Presently, wood waste burning projects are effectively limited to small-scale facilities because large-scale facilities are not economical. These developments are opportunistic and located near pulp, paper and paperboard industrial locations from which waste is available. EIA data indicate that in all of Virginia and North Carolina there are only 15 generating stations that are capable of burning wood waste, including industrial cogeneration, with a combined total summer capacity of 835 MW. However, many of these plants burn multiple fuels. Pro-rating the capacity of the amount of energy generated using wood-waste as a fuel yields 287 MW. (References 17 and 18) The counties and cities listed in Table 8.1-2 have 8 units totaling 579 MW capable of burning wood waste, which on a prorated basis yields 162 MW of wood waste potential.[1]

Additional development of wood waste generation is limited by the location and availability of additional wood waste resources. A report recently issued by DOE and USDA found that the amount of forestland-derived biomass that could be sustainably consumed nationally is approximately 368 million dry tons annually, which is more than 2.5 times the current national level. (Reference 24) However, the report cites accessibility of terrain, transportation costs, labor availability, and needed equipment improvements as major limiting factors in the expansion of biomass production. Section 8.3.6 of the GEIS found that the construction impacts per MW of

1. Ibid. (References 17 and 18).

installed capacity of a wood-burning project were similar to a coal project. These impacts are examined further in Section 9.2.3.

A report by NREL presents the current availability of biomass resources by state. (Reference 22) Table 9.2-2 shows the annual wood-derived biomass resource potential in Virginia.

In order to provide a similar capacity to Unit 3, approximately 8.6 million tons per year of biomass fuel would be needed. The Virginia RPS, described in Section 8.3.1.3 also provides state-wide, cumulative limitations on the use of certain types of biomass at 1.5 million tons for utilities that have received Virginia SCC approval to participate in a renewable energy portfolio standard program and who seek to meet statutorily-defined RPS goals.[1]

Wood waste material being used exclusively in a utility boiler has the characteristic of having a maximum installed capacity of approximately 65 to 100 MW. Additionally, saturation of this technology option in the DVP service territory could lead to fuel price volatility for DVP rate payers as the market dealing with woody biomass as a fuel for utility scale operations is not considered fluid, indeed the Legislation's 1.5 million ton statewide cap on certain types of biomass has the effect of limiting the potential of fuel volatility. While smaller installations of biomass power plants are considered viable options that support the Virginia RPS targets, the volumes needed to equal that of Unit 3 are considered to be unattainable; therefore, wood waste power is not a reasonable baseload alternative when compared to Unit 3.

9.2.2.1.6 Agriculture-Derived Biomass

A report recently issued by DOE and the U.S. Department of Agriculture found that biomass resources made available from agriculture could sustainably increase by a factor of five over the next 35 to 40 years. Currently 194 million dry tons of biomass, including manure and corn stover, is made available annually in the U.S. from agriculture, though only a small fraction of this total amount is converted into biofuel or bioenergy. (Reference 24) Technological processes for converting forms of biomass such as corn stovers and manure into energy are still in the developmental phase.

1. *See* Va. Code § 56-585.2(F), which states that utilities participating in RPS programs shall collectively "use or cause to be used no more than a total of 1.5 million tons per year of green wood chips, bark, sawdust, a tree or any portion of a tree which is used or can be used for lumber and pulp manufacturing by facilities located in Virginia towards meeting RPS goals." The 1.5 million tons is apportioned among the utilities based on each utility's share of "total electric energy sold to Virginia jurisdictional retail customers" during 2007 "excluding an amount equivalent to the average of the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants for the calendar years 2004 through 2006." Note that, even if Dominion Virginia Power were allotted full use of the 1.5 million tons in accordance with the RPS program, that would allow DVP to produce only 190 to 200 MW of electricity. The statute also allows other biomass fuels to be used without limitation, including slash, logging and construction debris, yard waste, non-merchantable waste paper, and agricultural and vineyard materials.

Some states have an abundance of agriculture-derived biomass in the form of animal waste products. These states want to use this resource as a multi-tiered solution that addresses RPS goals as well as provide economic relief for a sector of their supporting economy. Section 8.3.1.3 found that North Carolina has established targets to recover energy from swine waste and from poultry waste beginning in 2012. Such generating facilities are limited in capacity, availability and are not a viable alternative to Unit 3.

A report by NREL presents the current availability of biomass resources by state. (Reference 22) Table 9.2-3 shows the annual agriculture-derived biomass resource potential in Virginia is only 822,000 tons. Based on the foregoing, agriculture-derived biomass power is not a reasonable baseload alternative when compared to Unit 3.

Energy Crops

Currently, the use of energy crops in the U.S. is largely focused on producing ethanol for use in the transportation sector. Energy crops as feedstock for large-scale generation have not enjoyed the same attention or level of development. Section 8.3.8 of the GEIS states that energy crop technology is uneconomical when compared with traditional sources of baseload generation. According to the U.S. Climate Change Technology Program (Section 2.3.8), (Reference 25) energy crop technology for generation is not expected to approach goal levels until 2020, mainly due to cost inefficiencies and a lack of commercial demonstration. Factors that may hinder growth in biomass resource include urbanization of farm lands, increased demand in the international meat and food grain markets, and soil erosion caused by harvesting of biomass residues.

Because of the lower efficiency of these plants (approximately 30 percent), the land use requirements are many thousands of times greater than the land required to support nuclear. On an energy equivalent basis, the acreage required to support 1000 MW of baseload generation is approximately 600,000 acres. (Reference 26) Section 8.3.8 of the GEIS indicates that a crop-fired plant would have similar construction impacts and operational impacts as a wood-fired plant.

Switchgrass is an energy crop that has been tested at two coal plants owned by Southern Company. During a three-year demonstration period at the Gadsden Plant in Alabama between 2002 and 2004, switchgrass contributed between 7 percent and 10 percent of the energy produced. (Reference 27) One acre of a switchgrass plot can grow the energy equivalent of about 2–6 tons of coal per year. (Reference 27) On an energy equivalent basis, the acreage required to produce 1000 MW of baseload generation entirely from switchgrass is between 0.5 and 1.5 million acres. (Reference 28) The land area to produce switchgrass is not significantly different from that required for other energy crops. Additionally, this crop has only been used in relatively small proportion to fossil fuels in co-firing tests. It is not yet commercially viable to use switchgrass as either a secondary, much less primary, fuel source.

Due to their limited commercial potential and large land use requirements, energy crops are not a reasonable alternative to Unit 3.

9.2.2.1.7 **Photovoltaic Cells, Solar Thermal Power**

Consideration of solar technologies as an alternative to Unit 3 must first focus on whether they can be built as baseload capacity. Due to their intermittent nature during the day and lack of economic thermal storage devices for use at night, solar is not considered a baseload replacement option compared to Unit 3. Concentrated solar power and photovoltaic distributed generation generally are installed at the end-user location. According to GEIS Supplement 7, (Reference 12) photovoltaic cells have an average annual capacity factor of 25 percent. These estimates are high compared to EIA data in Table 9.2-1, which indicate that only 16 percent average annual capacity factors have been achieved across all solar technologies. Storage capability is not commercially available to serve as baseload generation. As noted by EPRI, improved technology for energy storage is necessary to enable deployment of solar as a baseload resource, but those advances are not projected to be achieved in time to meet the baseload need for the Dominion Zone.

GEIS Supplement 7 (Section 8.2.5.3) established that the areas surrounding the proposed project site for Unit 3 had a daily average generation potential of 4 kW-hrs per square meter compared with 7 to 8 kW-hrs per square meter achievable in certain parts of the western United States. It estimates land requirements of about 35,000 acres per 1000 MWe for photovoltaic and about 14,000 acres per 1000 MW for solar systems.

The use of solar energy for baseload, large-scale installations is not a reasonable alternative to Unit 3 due to its intermittent nature, and moderate solar insolation within the region of interest.

9.2.2.2 **Other Alternatives**

9.2.2.2.1 **Coal-fired IGCC**

An alternative coal-based technology is integrated gas-fired combined cycle technology (IGCC). This technology converts coal or petroleum coke or other products into synthetic gas (syngas) which is then used in a traditional gas-fired combined cycle plant. IGCC also offers the possibility, in the future, of capturing CO_2 before combustion. To date, carbon capture and sequestration (CCS) has not been proven on a commercial scale.

The NRC has recently observed that IGCC is not a reasonable alternative to a large nuclear power generation facility because: 1) existing IGCC plants have considerably smaller capacity, 2) system reliability of existing IGCC plants has been lower than pulverized coal plants, 3) existing IGCC plants have had extended shakedown periods, and 4) lack of overall plant performance warranties for IGCC plants have hindered commercial financing.[1] DVP also notes that existing U.S. plants received governmental subsidies and proposed new IGCC plants are being located in states offering tax incentives in support of the technology, a step that the Commonwealth of Virginia has not taken.

1. Reference 34, Volume 1 at 9-6.

Accordingly, IGCC with or without CCS, as a form of coal-fired technology, is not considered as a reasonable alternative to Unit 3.

9.2.2.2.2 Fuel Cells

According to the EIA's Annual Energy Outlook for 2007,[1] fuel cells are not projected to provide any measurable source of electric generation through 2030. On a per-kW basis, the installed costs (EIA assumes that the installed cost of a 10 MW fuel cell unit in 2006 is $4,520/kW (Reference 31)), plus variable operating plus maintenance costs for a fuel cell facility greatly exceed those of any other commercial-scale generating technology. The capital cost of advanced fuel cells is projected to remain uncompetitive with traditional sources of generation and the U.S. does not have an established hydrogen fuel supply structure. Hydrogen fuel is expensive and, like natural gas from which it is derived, it has a volatile price history. Because of its high marginal cost, a fuel cell would most likely be used in periods of peak electricity demand. Moreover, because fuel cell technology has a short operating history, the lifespan of a fuel cell unit is uncertain.

Dominion recently invested in the Raleigh, N.C.-based Microcell Corp. in order to accelerate the development of new fuel cell technology. (Reference 32) Microcell is a leader in proton exchange membrane microfiber fuel cells that operate on a cylindrical platform for applications ranging from back-up power to automotive.

Although DVP strongly supports the development of fuel cell technology, at this time, fuel cells are not a reasonable alternative to Unit 3.

9.2.2.3 Non Renewable Fuels

9.2.2.3.1 Petroleum Liquids

DVP currently operates 29 primarily oil-fired combustion turbines and two oil-fired steam turbines at eight different sites within the Dominion Zone, with a total maximum deliverable capacity (MDC) of 2246 MW. This equates to approximately 12 percent of installed capacity of DVP's Virginia and North Carolina power fleet.(Reference 23) A petroleum liquids alternative to the proposed unit would result in an approximate doubling of DVP's exposure to petroleum price volatility. From an environmental perspective, Section 8.3.11 of the GEIS finds that oil units have comparable air emissions to coal units.[2] In addition, the marginal cost of producing electricity with oil-fired generation is much higher than the marginal cost of energy produced by a nuclear unit, and as a result oil-fired generation is less desirable as a baseload generation source. At a time when oil commodity price levels remain high when compared with the commodity cost of coal or nuclear fuel, this is not an economically competitive option.

1. Reference 30, Tables A8 and A9.
2. Coal emissions are discussed in Section 9.2.3.

Petroleum liquid generation is not a reasonable baseload alternative to Unit 3 on either an environmental or economic basis.

9.2.2.3.2 Natural Gas-Fired Generation

DVP chose to evaluate gas-fired generation, using combined-cycle technology because the technology is mature, economical and feasible; and DVP has experience operating several combined-cycle gas units. One of DVP's most recently commissioned combined-cycle plants, Possum Point Unit 6, became commercially operable in July 2003. Possum Point 6 has a capacity of approximately 540 MW. For the purposes of this analysis, DVP assumed a new combined-cycle plant would have a capacity of approximately 550 MW; thus, DVP evaluated three units, in order to be compatible with the project, for a total capacity of 1650 MW. Combined-cycle technology is considered a competitive alternative and is evaluated further in Section 9.2.3.

9.2.2.3.3 Coal-Fired Generation

In 2004, the General Assembly amended the Virginia Electric Utility Restructuring Act to add a new subsection §56-585.G to encourage the construction of a coal-fired generation facility in the coalfield region of Virginia that would use coal from that region. Consistent with the 2004 Virginia legislation, DVP supports the development of coal technologies. Accordingly, coal is considered a potential alternative, and thus discussed further in Section 9.2.3.

9.2.2.4 Evaluation of Combinations of Alternatives

This section examines whether combinations of alternatives could generate baseload power in an amount equivalent to the proposed Unit 3. There are numerous possible combinations of power sources and the amount of output of each source. For the renewal of licenses pursuant to 10 CFR 54, the NRC has already determined that expansive consideration of combinations would be too unwieldy given the purposes of the alternatives analysis. (Reference 14)

The following analysis provides the basis for evaluating whether a combination of alternative energy sources is a viable option and, if so, whether it provides any difference in environmental impacts with respect to evaluating possible alternatives to Unit 3. Section 9.2.2.4.1 evaluates whether any combination of renewables with non-renewable fuels is a viable and reasonable means of providing baseload power in the Dominion Zone. Section 9.2.2.4.2 evaluates whether any combination of non-renewable fuels provides a different set of environmental impacts than individual non-renewable fuel facilities such that a separate analysis of the environmental impacts of the combination is necessary.

9.2.2.4.1 Combinations of Alternatives Involving Renewable Fuels

As discussed in Section 9.2.2.1, renewable resources are not of the scale or type to provide baseload power. Wind and solar are not feasible on their own to generate the equivalent baseload capacity or output of Unit 3 because of the intermittent nature of the resources, as discussed in

Section 9.2.2.1.1 and Section 9.2.2.1.7. As discussed below, no combination of a renewable fuel facility and a non-renewable fuel facility is a viable alternative to provide baseload generation in the Dominion Zone at the equivalent capacity of Unit 3.

Wind and Non-Renewable Fuels

As discussed above, wind power is considered by the industry as an intermittent, non-baseload generation resource. Accordingly, any combination of wind power with a non-renewable fuel facility would require not only that two facilities would be built—the wind facility and the non-renewable fuel facility—with the concomitant construction impacts of each, but that based on wind power's lower capacity factor the reduction in emissions would conservatively be only approximately 23 percent. Accordingly, a combination of a wind power with non-renewable fuel facility is not a viable or reasonable alternative to Unit 3.

Photovoltaic Cells, Solar Thermal Power and Non-Renewable Fuels

A combination of photovoltaic cells, solar thermal power, and non-renewable fuel alternatives would require, and have the impacts of, construction of two separate facilities. Also like wind power, a conservative assumption for the effect of such a facility on the air emissions and solid waste associated with a non-renewable fuel facility would be an approximate reduction of 16 percent to 25 percent. Due to the low capacity factor of a solar resource, although the combination of solar and non-renewable fuels may be viable on a small-scale, it is not a reasonable alternative to Unit 3.

Biomass, Wood Waste, Fuel Crops and Non-Renewable Fuels

As described above, there are not large-scale installations for the use of various types of biomass facilities in the Dominion Zone. Many of these opportunities would result in only small-sized facilities with lower capacity output compared to Unit 3. A combination of such a facility with a non-renewable fuel facility also has land impacts in the case of fuel crops. In addition, the combination of biomass, wood waste, or fuel crops and a non-renewable fuel facility is not a viable or reasonable alternative to Unit 3.

MSW and Non-Renewable Fuels

As described in Section 9.2.2.1.4, MSW projects could achieve capacity factors of 85–90 percent. However, site development of MSW projects is limited to landfill sites and is driven by waste management considerations. There are limited identified opportunities for such facilities in the Dominion Zone and a comparable-sized facility to Unit 3 would require 4.5 million tons of MSW. Pairing a smaller facility with a non-renewable fuels facility would only proportionally reduce the amount of MSW needed for such a facility. Thus, a combination MSW and non-renewable fuel alternative is not a viable or reasonable alternative to Unit 3.

9.2.2.4.2 **Combinations of Alternatives Involving Non-Renewable Fuels**

Any combination of coal- and natural gas-fired facilities would have the characteristics set forth in Section 9.2.3. In the analysis presented in Section 9.2.3, neither coal- nor natural gas-fired generation is environmentally preferable to Unit 3. Thus, no combination of coal- and natural gas-fired generation will be environmentally preferable to Unit 3. Likewise, as discussed in Section 9.2.2.3.1, oil-fired generation is not a reasonable alternative to Unit 3 on an environmental or economic basis. Further because oil-fired generation has comparable emissions to a coal-fired plant, no combination of oil-, coal- or natural gas-fired facilities is environmentally preferable to Unit 3. Accordingly, combinations of non-renewable fuels are not environmentally superior to Unit 3, are already bounded by the analysis in Section 9.2.3, and therefore do not need to be assessed separately from the analysis in Section 9.2.3.

9.2.3 Assessment of Alternative Energy Sources and Systems

This section analyzes the possible alternative energy sources and systems, and evaluates their ability to have an appreciable reduction in overall environmental impact. The alternative energy sources evaluated in this section are coal and natural gas.

9.2.3.1 Coal-Fired Generation

For purposes of assessing the alternatives to Unit 3, a generic pulverized coal facility with supercritical boiler is analyzed. Specifically, the coal-fired alternative assumes three approximately 507 MW net output, pulverized coal-fired units with a wet scrubber for flue gas desulfurization (FGD) with approximately 95 percent SO_x removal efficiency, as well as low NO_x burners, overfire air, and SCR with approximately 80 percent NO_x removal efficiency. Particulate matter (PM-10) is reduced in a dry electrostatic precipitator (ESP).

The following emissions data represent pro-rated emissions assuming proxy state-of-the-art coal plants were sized similarly to Unit 3 (approximately 1500 MW) and operated at a 90 percent capacity factor burning 2.65 percent sulfur Eastern bituminous coal.

9.2.3.1.1 Air Quality Impacts

Dust emissions from construction activities for a coal-fired generation plant would be similar to those from any similar construction project. Such emissions would be temporary, mitigated using best management practices, and therefore small.

During its operating life, the emissions profile regarding air quality from coal-fired generation will vary significantly from that of nuclear power generation because of emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), particulates, and other constituents. DVP has assumed generically that a plant design that would be selected and managed to minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. The estimated coal-fired alternative emissions for SO_x, NO_x, CO, and particulate matter (PM), are provided in Table 9.2-4.

Table 9.2-4 provides DVP's emissions calculation formula and estimates for three typical plant configurations, normalized to 1500 MW, which are then used to present the range of emissions for the generic plant described in Section 9.2.3.1.

The US Environmental Protection agency has indicated that the average CO_2 emissions rate for a coal-fired plant is 2249 lb/MW-hrs. Thus, an approximately 1500 MW coal-fired plant would emit approximately 13.5 million tons of CO_2 annually. The supporting calculations are provided in Table 9.2-5.

9.2.3.1.2 Water Quality and Use

DVP expects that a coal-fired alternative would use conventional mechanical draft cooling towers. DVP forecasts that plants may have a range of water consumption, and three examples of water consumption are provided in Table 9.2-6.

Blowdown from the cooling towers and other plant discharges would meet limits established in a VPDES permit. Accordingly, the impact of such discharges on water quality and aquatic life would be small.

Impacts to aquatic resources and water quality would be minimized through the use of mechanical draft towers. Consumptive use of water could be considered small to moderate depending on plant location and application of further mitigation measures. Consumptive water use would not differ significantly from a similarly sized nuclear unit with the same cooling water system.

9.2.3.1.3 Coal Combustion Byproduct (CCB) Management

DVP concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste.[1] DVP's calculations regarding the range of CCB produced are set forth in Table 9.2-7.

Based on the calculations in Table 9.2-6, DVP believes that CCB disposal for the coal-fired alternative would have moderate impacts; the impacts would be clearly noticeable, but would not destabilize resources, and that further mitigation would be unwarranted.

9.2.3.1.4 Socioeconomic Impact

A coal-fired alternative would offer a number of local and regional economic benefits including: construction jobs, permanent jobs, property taxes to its host community for the life of the facility, consumption of a large quantity of coal produced by Virginia mines, and the additional economic multiplier effect of such a project on the regional economy. Construction of a similarly-sized facility, using clean-coal technology, would have an overnight cost in the range of $2,500 to $3,000 (depending on technology and location) per kW. The construction of a generic 1500 MW coal-fired plant would offer similar incremental employment opportunities when compared to Unit 3. The GEIS estimated that a 1000 MW coal-plant would require a peak load workforce of 1200 to 2500 workers

1. Reference 36, Section 8.3.9.

during construction.[1] Given that the alternative described in this section is larger than 1000 MW, DVP expects that the construction workforce would be modestly larger than that identified by the NRC. Further operation of the plant would require permanent employment of approximately 200 plant operators. A coal project would further enhance the Virginia economy through local property tax contributions and consumption of large amounts of regional coal and limestone every year, creating approximately 360 mining jobs. In addition, like the proposed Unit 3, a coal-fired station is expected to provide significant tax revenue for the local economy. Overall, similar to Unit 3, the socioeconomic impact of a coal-fired plant would be small to moderately beneficial.

9.2.3.1.5 **Other Impacts**

Other impacts from a coal-fired alternative include impact on terrestrial habitat on approximately 300 acres for the construction of the power block and coal storage area. As with any large construction project, some erosion, sedimentation, and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. It is assumed that construction debris from clearing and grubbing could be disposed of onsite and municipal waste disposal capacity would be available.

The GEIS indicates that a 1000 MW coal-fired facility would require approximately 1700 acres which is comparable to the total NAPS site area.[2] Moreover, even if sited elsewhere, beneficial reuse of land formerly used for surface coal mining or other mine related activities may be possible, minimizing land use and impacts on terrestrial habitat and other ecological resources.

Air emissions would be required to meet standards established under the Clean Air Act. These standards are established at levels deemed protective of the public health. Accordingly, health impacts would be small. The potential for accidents affecting public health or the environment is also small.

The plant structures would be an incremental visual impact. Plant operations and routine noise would also contribute to an impact on aesthetics. Such impact could range from small to moderate depending on plant location and mitigation measures.

Impacts on cultural resources would not be markedly different from impacts associated with other alternative generating facilities of similar size. With proper consideration of cultural resources during siting, and appropriate survey and recovery techniques during construction, such impacts would be small.

9.2.3.1.6 **Conclusion**

Current supercritical coal plant designs, utilizing FGD, SCR and ESP equipment, provide a substantial reduction in airborne emissions when compared to a traditional pulverized coal unit

1. Reference 36, Section 8.3.9 and Reference 44, Section 8.2.1.
2. Reference 36, Section 8.3.9 and Reference 44, Section 8.2.1.

without such emission reduction technologies. However, even with the advanced design for emission reduction systems, a coal plant would not appreciably reduce the environmental impacts relative to proposed Unit 3. As a result, DVP concludes that a supercritical pulverized coal plant is not environmentally preferable to the proposed project.

9.2.3.2 **Natural Gas**

For purposes of assessing the generic alternatives to Unit 3, and in part based on equipment availability, a standard gas-fired facility is used as a proxy. Specifically, DVP has based this analysis on a three unit natural-gas-fired, combined-cycle plant, with each unit generating approximately 500 MW of net capacity. Each unit consists of two 165 MW gas turbines (e.g., General Electric Frame 7FA), and two heat-recovery steam generators followed by a nominal 170 MW capacity Steam Turbine Generator were considered for a total of approximately 1500 MW net. DVP based its emission control technology and emission control assumptions on alternatives that the EPA has identified as being available for minimizing emissions. The facility is assumed to include SCR with steam/water injection with 80 percent removal efficiency.

DVP has assumed that there would be sufficient natural gas available although no studies have been undertaken to confirm that sufficient baseload gas supplies could be economically delivered.

While combined-cycle technology is a potential source of baseload generation due to its mature technology and efficient operating characteristics, the costs of natural gas have become very volatile in recent years making it a less attractive source of baseload power than the proposed Unit 3. Moreover, as noted in Section 8.0.1.2, natural gas plants have accounted for more than 90 percent of all new electric generating capacity added in the U.S. over the past five years. Natural gas has many desirable characteristics and should be part of, but not dominate, the fuel mix because "over-reliance on any one fuel source leaves consumers vulnerable to price increases, volatility and supply disruptions." (Reference 41)

9.2.3.2.1 **Air Quality Impacts**

Natural gas is a relatively clean combusting fossil fuel. High efficiency is achieved in a combined cycle operation through the utilization of a heat recovery steam generator. With little or no firing of natural gas into the heat recovery steam generator, the combined cycle alternative would have similar types of emissions to those of the coal-fired alternative.

Table 9.2-8 and Table 9.2-9 summarize the emissions estimates for the combined-cycle gas alternative, assuming a capacity factor of 90 percent.

Clean Air Act requirements and the Virginia Department of Environmental Quality's regulations are also applicable to the gas-fired generation alternative. Air quality impacts would therefore be moderate, but any emission from a natural gas-fired combined cycle unit would be in excess of those from nuclear generation.

The US Environmental Protection Agency has indicated that the average CO_2 emissions rate for a gas-fired plant is 1135 lb/MW-hrs. Thus, an approximately 1500 MW gas-fired unit would emit approximately 6.7 million tons annually. The supporting calculations are provided in Table 9.2-10.

Like a coal or nuclear plant, construction of a gas-fired unit would result in some fugitive dust emissions typical of any construction project of similar size. Such impacts would be temporary, controlled by best management practices, and therefore small.

9.2.3.2.2 **Water Quality and Use**

DVP expects that a gas-fired combined cycle alternative would use conventional mechanical draft cooling towers. A gas-fired combined-cycle plant may have a range of water consumption, three examples of which are provided in Table 9.2-11. The consumptive use of water could be considered small to moderate depending on plant location and application of further mitigation measures.

Blowdown from the cooling towers and other plant discharges would meet limits established in a VPDES permit. Accordingly, the impact of such discharges on water quality and aquatic life would be small.

9.2.3.2.3 **Waste Management**

Gas-fired generation generates almost no waste, with the exception of the spent catalyst used for NO_x control. DVP concludes that gas-fired generation waste management impacts would be minimal.

9.2.3.2.4 **Socioeconomic Impact**

The GEIS concluded that the construction workforce and local and state tax revenue would be smaller than a coal unit's.[1] Additionally, the construction period would be shorter than either coal or nuclear. The GEIS estimated that the full-time workforce of an approximately 1500 MW(e) plant would be 150, the lowest of any technology.[2] Based on experience DVP anticipates this number to be lower and estimates approximately 30 to 50 workers for a plant this size. However, socioeconomic impacts would result from the workforce needed to operate the gas-fired facility, as well as local tax revenues from the facility.

9.2.3.2.5 **Other Impacts**

The GEIS estimated that 110 acres would be needed for a plant site.[3] In addition to site specific impact, the terrain near the site may be affected by the underground construction of a natural gas pipeline. To the extent practicable, the pipeline route would utilize previously disturbed rights-of-way to minimize impacts. The pipeline construction management practices would be expected to minimize soil loss and restore vegetation immediately after the excavation is backfilled. There

1. Reference 44, Section 8.2.2
2. Reference 36, Section 8.3.10; Reference 44, Section 8.2.2
3. Reference 36, Section 8.3.10; Reference 44, Section 8.2.2

would be some disturbance of wildlife and habitat during pipeline construction. DVP expects these impacts would be minimized and that they would not result in a long-term reduction in the local or regional diversity of plants and animals.

Air emissions would be required to meet standards established under the Clean Air Act. These standards are established at levels deemed protective of the public health. Accordingly, health impacts would be small. The potential for accidents affecting public health or the environment is also small.

The plant structures would be an incremental visual impact. Plant operations and routine plant noise would contribute to a small aesthetic impact.

Impacts on cultural resources would not be markedly different from impacts associated with other alternative generating facilities of similar size. With proper consideration of cultural resources during siting, and appropriate survey and recovery techniques during construction, such impacts would be small.

9.2.3.2.6 **Conclusion**

Current combined cycle plant designs, utilizing low NO_x burners and SCR equipment, provide for minimal airborne emissions. However, even with heat recovery steam generators, the advanced design for power generation realized in a combined cycle plant would not appreciably reduce the environmental impacts relative to proposed Unit 3. As a result, DVP concludes that a gas-fired combined cycle plant is not environmentally preferable to the proposed Unit 3 project.

9.2.4 **Conclusion**

As analyzed in this Chapter 9, based on environmental impacts, DVP has concluded that neither a coal-fired nor a gas-fired plant would provide an appreciable reduction in overall environmental impact relative to a nuclear plant and neither is environmentally preferable to the proposed Unit 3.

Section 9.2 References

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Table 9.2-1 Average Capacity Factors for Renewable Resources[a]

Capacity Factor By Sector (%)	2001	2002	2003	2004	2005	Average
Biomass	32.7	34.4	35.8	34.6	35.1	34.5
Wood/ Wood Waste	16.1	17.6	18.5	18.0	19.5	17.9
MSW/Landfill Gas	64.2	64.2	64.1	66.8	67.0	65.3
Other Biomass[b]	20.8	32.5	52.2	43.5	33.4	36.5
Geothermal	70.8	73.5	77.2	78.6	73.4	74.7
Conventional Hydroelectric	30.9	37.5	39.4	39.0	39.3	37.2
Solar	15.8	16.0	15.4	16.5	15.3	15.8
Wind	19.9	26.8	21.3	25.0	23.4	23.3

a. References 9 and 10 (the capacity factor was calculated using the following formula:
Capacity Factor = Annual generation (MW-hr)/(Annual net summer capacity * 24 hours * 365 days)).

b. Includes agriculture by-products/crops, sludge waste, tires, and other biomass solids, liquids, and gases.

Table 9.2-2 Wood-Derived Biomass Resource Potential

	Virginia (thousand tons)
Forest Residues	2,403
Primary Mill	2,147
Secondary Mill	62
Urban Wood	813
Total Wood Biomass	5,425

Table 9.2-3 Agriculture-Derived Biomass Resource Potential

	Virginia (Thousand tons)
Switchgrass	297
Crop Residues	502
Methane from Manure Management	23
Total Agriculture Biomass	822

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant A Emission Calculations

Typical Plant A output =	600	MW	
Typical Plant A heat rate =	8800	Btu/kW-hrs	
Typical Plant A heat input =	5280	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant A Output ratio	2.500	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant A Emissions (lb/MMBtu)	Annual emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	heat input	Hrs/ year	cap. fac	output ratio	lb/ ton	tons/ year
PM with Condensables	0.018	0.018*	5280*	8760*	0.9*	2.5/	2000 =	937
NO_x	0.04	0.04*	5280*	8760*	0.9*	2.5/	2000 =	2081
SO_2 Controlled	0.08	0.08*	5280*	8760*	0.9*	2.5/	2000 =	4163
VOC	0.0035	0.0035*	5280*	8760*	0.9*	2.5/	2000 =	182
CO	0.09	0.09*	5280*	8760*	0.9*	2.5/	2000 =	4683

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant B Emission Calculations

Typical Plant B output =	700	MW	
Typical Plant B heat rate =	8900	Btu/kW-hrs	
Typical Plant B heat input =	6230	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant B Output ratio	2.143	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant B Emissions (lb/MMBtu)	Annual Emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	heat input	Hrs/ year	cap. fac	output ratio	lb/ ton	tons/ year
PM with Condensables	0.029	0.029*	6230*	8760*	0.9*	2.143/	2000=	1526
NO_x	0.06	0.06*	6230*	8760*	0.9*	2.143/	2000=	3158
SO_2 Controlled	0.13	0.13*	6230*	8760*	0.9*	2.143/	2000=	6841
VOC	0.005	0.005*	6230*	8760*	0.9*	2.143/	2000=	263
CO	0.105	0.105*	6230*	8760*	0.9*	2.143/	2000=	5526

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant C Emission Calculations

Typical Plant C output =	800	MW	
Typical Plant C heat rate =	9000	Btu/kW-hrs	
Typical Plant C heat input =	7200	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant C Output ratio	1.875	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant C Emissions (lb/MMBtu)	Annual emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	heat input	Hrs/ year	cap. fac	output ratio	lb/ ton	tons/ year
PM with Condensables	0.04	0.04*	7200*	8760*	0.9*	1.875/	2000=	2129
NO_x	0.08	0.08*	7200*	8760*	0.9*	1.875/	2000=	4257
SO_2 Controlled	0.18	0.18*	7200*	8760*	0.9*	1.875/	2000=	9579
VOC	0.0065	0.0065*	7200*	8760*	0.9*	1.875/	2000=	346
CO	0.12	0.12*	7200*	8760*	0.9*	1.875/	2000=	6386

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant Range of Emissions

Emitted Compound	Emission Range tons/year	Plant A	Plant B	Plant C	High	Low
PM with Condensables	940–2130	937	1526	2129	2130	940
NO_x	2080–4260	2081	3158	4257	4260	2080
SO_2 Controlled	4160–9580	4163	6841	9579	9580	4160
VOC	180–350	182	263	346	350	180
CO	4680–6390	4683	5526	6386	6390	4680

Notes:

1) The above is based on a typical state-of-the-art supercritical coal fired power plant burning Eastern Bituminous coal with 0.7% to 4.0% sulfur and typical higher heating values between 12,630 to 15,600 Btu/lb.

2) The emissions are in tons/year prorated to the electrical generation output of NAPS Unit-3 (1500 MW)

3) The PM with condensable is PM10, because the air quality controls system (baghouse) removes most of the particulate matter >10 microns in size.

4) The NO_x is reduced by SCR with approximately ~80% removal efficiency.

5) Although coal-fired plants may also be subject to other air emission limits including Hg, Pb, NH_3, HCl, etc., these were not calculated.

6) Annual Capacity factor is 90%. The high, low values, and the range have been rounded to the nearest 10 tons/year.

7) Emissions are based on a base loaded plant and thus, they do not include startup or part-load emissions.

Table 9.2-4a Coal Combustion By-Products and Air Emission Parameters (1500 MWe)

CCB	Annual CCB Quantity[1] (tons)	CCB Beneficial Reuse[2] (%)	CCB Industry Usage
Ash (recovered)	110,000 to 472,000	25	construction fill material, mine reclamation, raw material in manufacturing of cement products
Flue Gas Desulfurization (FGD) Gypsum	123,000 to 887,000	0	used as synthetic gypsum in wall board and cement manufacturing

Annual Air Emission Source	Emission Rates
Mercury (Hg)	0.37 to 0.94 tons/year
PM_{10}	940 to 2,130 tons/year
$PM_{2,5}$	540 to 1,240 tons/year

Lifetime Landfill Capacity Needed for Disposal of Recovered Ash[3] – 45 to 195 acres

Lifetime Landfill Capacity Needed for Disposal of FGD Gypsum[3] – 45 to 326 acres

Consumption of Limestone for Environmental Control of Air Emissions – 78,000 to 560,000 tons/year

Notes:

1. The ranges above are based on a typical state-of-the-art supercritical coal-fired power plant burning Eastern Bituminous coal with sulfur content between 0.7% and 4.0%, and typical heating values of 12,630 to 15,600 Btu/lb.
2. Industry usage for FGD gypsum is not as widespread as usage for ash, therefore, 0% is used as a conservative reuse value for FGD gypsum.
3. The lifetime of the plant is assumed to be 60 years.

Table 9.2-5 CO_2 Emissions of Coal Technologies

Coal (Assumes Annual Capacity Factor of 90%)

Emissions Rate: 2,249 lb/MW-hrs[a]

Annual CO_2 Emissions:

$$2249\text{lb/MW-hrs} \times \frac{1}{2000}\text{ton/lb} \times 1500\ \text{MW} \times 90\% \times 8760\ \text{hours/year}\ =\ 13{,}298{,}337\ \text{tons/year}$$

a. Reference 40

Table 9.2-6 Coal-Fired Power Plant Water Consumption

Coal Fired Plants

	Plant MW	Total Use (gpm)	Use Per MW (gpm)	Use per MW (Rounded per Section 3.3) (gpm)
Example 1	858	8477	9.88	9
Example 2	1600	18150	11.34	11
Example 3	568	7969	14.03	15

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Supercritical Plant Ash Generation Rate Calculations

	Typical Plant A	Typical Plant B	Typical Plant C
Net Electrical Output (E), MW	600	700	800
Plant Heat Rate (HR), BTU/kW-hr	8800	8900	9000
Coal Higher Heating Value (HV) - Low, BTU/lb	12630	12630	12630
Coal Higher Heating Value (HV) - High, BTU/lb	15600	15600	15600
Coal Firing Rate (F) - Low, tons/hr	169	200	231
Coal Firing Rate (F) - High, tons/hr	209	247	285
Percent Ash,% (Attachment 4)	3.3	9.1	11.2
Ash Generation Rate (A) - Low, tons/hr	5.6	18.2	25.8
Ash Generation Rate (A) - High, tons/hr	6.9	24.7	31.9
Annual Ash Recovery - Low, tons/yr	43985	143116	203567
Annual Ash Recovery - High, tons/yr	54328	194253	251437
Plant Power Adjustment Ratio (equal to 1500 MW divided by the rating of the Typical Plant, MW)	2.500	2.143	1.875
Equivalent Annual Recovery 1500 MW - Low, tons/yr	109963	306676	381689
Equivalent Annual Recovery 1500 MW - High, tons/yr	135821	416256	471444
Equivalent Annual Recovery per MW Net Output - Low, tons/yr	73	204	254
Equivalent Annual Recovery per MW Net Output - High, tons/yr	91	278	314

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Supercritical Plant Ash Generation Rate Calculations

	Typical Plant A	Typical Plant B	Typical Plant C

$$F = \frac{(E)MW(HR)\,{}^{BTU}\!/_{kWhr}(1000)\,{}^{kW}\!/_{MW}}{(HV)\,{}^{BTU}\!/_{lb}(2000)\,{}^{lb}\!/_{ton}} = \frac{(E)(HR)}{2(HV)}\,{}^{tons}\!/_{hr}$$

$$A = \frac{(\%\,Ash)(F)}{100}\,{}^{tons}\!/_{hr}$$

Annual Ash Recovery = $\frac{(0.9)(8760)\,{}^{hr}\!/_{yr}\,(99.9)\%\,(A)\,{}^{tons}\!/_{hr}}{(100)\%} = \frac{(0.9)(8760)(99.9)}{100}\,{}^{tons}\!/_{yr}$

These results are based on the following assumptions:

1. The plant capacity factor is assumed to be 90% based on Owner input.

2. The ash recovery efficiency is assumed to be 99.9%.

3. Plant heat rates are assumed to range from 8800 BTU/kW-hrs to 9000 BTU/kW-hrs.

4. Two values of coal higher heating value are assumed: 12,630 BTU/lb and 15,600 BTU/lb.

5. Assumed low, intermediate, and high values of ash content in the coal are obtained from Table 17 of *Steam/its generation and use*, 39th Edition, Babcock and Wilcox for coals ranked 9, 10, and 8, respectively.

6. All calculations are for continuous base load operation and do not include startup, shutdown and/or part load operation.

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant A- Gypsum production

Typical Plant A Output	600	MW net
Typical Plant A heat rate	8800	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	2.5	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	0.7	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	×	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	×	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW		mmBtu/hr	Btu/lb		lb/hr	tons/year		tons/year	
Typical Plant A	600		5,280.00	15,600	5280x1E6/15600=	338,462	49,147.33		31,004.71	
NAPS U3 estimates:	1500	5280*2.5 =	13,200.00	15,600	13200x1E6/15600=	846,154	49147.33*2.5=	122,868	31004.71*2.5=	77,512

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant A- Gypsum production

		Typical Plant A calculations:				
Sulfur load to firing chamber	=	0.007*	338,462	=	2,369	lb/hr
	Net Output	Heat Input		Coal heating value	Coal firing rate	
	MW		mmBtu/hr	Btu/lb		lb/hr
		2369/	32.064	=	73.89	lb-moles/hr
SO_2 in flue gas	=	73.89*	64.06	=	4,733	lb/hr
$S + O_2 \rightarrow SO_2$						

SO_2 captured and reacted	=	0.98*	4,733	=	4,639	lb/hr
		4639/	64.06	=	72.41	lb-moles/hr
SO2 reaction with gypsum production						
SO_2+$CaCO_3$ +½O_2 + 2H_2O ($CaSO_4$.2H_2O)+ CO_2						
Only reaction considered						
$CaCO_3$ consumed	=	72.41*	100.09	=	7,248	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	7248/	0.97/0.95	=	7,865	lb/hr
Limestone required annually	=	8760/2000 *0.9*	7,865	=	31,005	tons/year
Gypsum produced	=	72.41*	172.174	=	12,468	lb/hr
Gypsum produced annually	=	8760/2000 *0.9*	12,468	=	49,147	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant B- Gypsum production

Typical Plant B Output	700	MW net
Typical Plant B heat rate	8900	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	2.142857	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	2.2	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	×	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	×	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW		mmBtu/hr	Btu/lb		lb/hr		tons/year		tons/year
Typical Plant B	700		6,230.00	14,115	6230x1E6/ 14115=	441,374		201,429.19		127,072.10
NAPS U3 estimates:	1500	6230*2.142857=	13,350.00	14,115	13350x1E6/14115=	945,802	201429.19*2.142857=	431,634	127072.1*2.142857=	272,297

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant B- Gypsum production

		Typical Plant B calculations:				
Sulfur load to firing chamber	=	0.022*	441,374	=	9,710	lb/hr
		9710/	32.064	=	302.84	lb-moles/ hr
SO_2 in flue gas	=	302.84*	64.06	=	19,400	lb/hr
$S + O_2 \rightarrow SO_2$						
SO_2 captured and reacted	=	0.98*	19,400	=	19,012	lb/hr
		19012/	64.06	=	296.78	lb-moles/ hr
SO2 reaction with gypsum production						
SO_2+$CaCO_3$ +½O_2 + 2H_2O ($CaSO_4$.2H_2O)+ CO_2						
Only reaction considered						
$CaCO_3$ consumed	=	296.78*	100.09	=	29,705	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	29705/	0.97/0.95	=	32,235	lb/hr
Limestone consumed annually	=	8760/2000*0.9*	32,235	=	127,072	tons/year
Gypsum produced	=	296.78*	172.174	=	51,098	lb/hr
Gypsum produced annually	=	8760/2000*0.9*	51,098	=	201,429	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant C- Gypsum production

Typical Plant C Output	800	MW net
Typical Plant C heat rate	9000	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	1.875	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	4.00	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	X	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	X	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW	mmBtu/hr		Btu/lb		lb/hr	tons/year		tons/year	
Typical Plant C	800		7,200.00	12,630	7200x1E6/12630=	570,071	473,022.39		298,407.33	
NAPS U3 estimates:	1500	7200*1.875=	13,500.00	12,630	13500x1E6/12630=	1,068,884	473022.39*1.875=	886,917	298407.33*1.875=	559,514

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant C- Gypsum production

Typical Plant C calculations:						
Sulfur load to firing chamber	=	0.04*	570,071	=	22,803	lb/hr
		22803/	32.064	=	711.17	lb-moles/hr
SO_2 in flue gas	=	711.17*	64.06	=	45,557	lb/hr
$S + O_2\ SO_2$						
SO_2 captured and reacted	=	0.98*	45,557	=	44,646	lb/hr
		44646/	64.06	=	696.94	lb-moles/hr
SO2 reaction with gypsum production						
SO_2+$CaCO_3$ +½O_2 + 2H_2O ($CaSO_4.2H_2O$)+ CO_2						
Only reaction considered						
$CaCO_3$ consumed	=	696.94*	100.09	=	69,757	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	69757/	0.97/0.95	=	75,699	lb/hr
Limestone required annually	=	8760/2000*0.9*	75,699	=	298,407	tons/year
Gypsum produced	=	696.94*	172.174	=	119,996	lb/hr
Gypsum produced annually	=	8760/2000*0.9*	119,996	=	473,022	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical Supercritical PC Fired plant

Gypsum Production & Limestone Consumption summary:

	Annual Range	Plant A	Plant B	Plant C	High	Low
	Tons/year	**Tons/year**	**Tons/year**	**Tons/year**	**Tons/year**	**Tons/year**
Gypsum Produced	123000 - 887000	122,868	431,634	886,917	887,000	123,000
Limestone Consumed	78000 - 560000	77,512	272,297	559,514	560,000	78,000

Notes:

1) The calculation is based on Eastern Bituminous Coal with a typical sulfur content of 0.7 to 4.0% (0.7%, 2.2%, & 4.0% used) typical higher heating values of 12,630 to 15,600 Btu/lb.

2) Calculation based on typical pulverized coal fired supercritical plants with heat rates between 8800 to 9000 Btu/kW-hrs.

3) The calculation uses a 90% capacity factor. All annual rates are based on the 90% capacity factor.

4) Gypsum production for typical plant is based on a 98% SO_2 removal efficiency.

5) The calculation has been corrected for the expected net output from NAPS-U3 of 1500 MW net.

6) Gypsum production for typical plant is based on a 90% dry gypsum (for landfill).

7) Limestone purity is assumed to be 95%, and utilization factor is assumed to be 97%, this is typical.

8) The High, Low, and the annual range has been rounded of to the nearest 1,000.

Table 9.2-8 Gas-Fired Generation (Combined-Cycle) Operational Characteristics

Assumption	Source
Station Capacity 1500 MW (net)	Assumed Capacity of three combined-cycle units
Heat Rate 7000 Btu/kW-hrs	DVP's experience with similar units
Primary Fuel Natural Gas	
Emissions Control Technology SCR (Selective Catalytic Reduction)	
Emissions Removal Rate (Reference 38) 80%	Assumed Removal Rate for NO_x and CO
NO_x Emissions Rate (References 42 and 43) 0.01 lb/MMbtu	Water-steam injection with SCR- control technology
SO_x Emissions Rate (Reference 39) 0.0034 lb/MMbtu	
CO Emissions Rate (Reference 39) 0.006 lb/MMbtu	Water-steam injection with SCR- control technology
PM-10 Emissions Rate (References 42 and 43) 0.011 lb/MMbtu	
VOC Emissions Rate (Reference 39) 0.0021 lb/MMbtu	
Capacity Factor (High) 90%	

Table 9.2-9 Emissions Logic – Gas-fired Combined Cycle, 90% Capacity Factor

Annual Gas Burn

$$1500\ \text{MW} \times \frac{7000\ \text{BTU}}{\text{kW-hr}} \times \frac{1\ \text{MMBTU}}{10^6\ \text{BTU}} \times \frac{1000\ \text{kW}}{1\ \text{MW}} \times \frac{90\%}{\text{Capacity Factor}} \times \frac{8760\ \text{hours}}{1\ \text{year}} = 82{,}782{,}000\ \text{MMBTU/year}$$

NO_x Emissions

$$\frac{0.01\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 414\ \text{tons/year}$$

SO_x Emissions

$$\frac{0.0034\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 141\ \text{tons/year}$$

CO Emissions

$$\frac{0.006\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 248\ \text{tons/year}$$

PM-10 Emissions

$$\frac{0.011\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 455\ \text{tons/year}$$

VOC Emissions

$$\frac{0.0021\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 87\ \text{tons/year}$$

Table 9.2-10 CO_2 Emissions of Natural Gas Technologies

Natural Gas (Assumes Annual Capacity Factor of 90%)

Emissions Rate: 1135 lb/MW-hrs (Reference 40)

Annual CO_2 Emissions:

$$\frac{1135\ \text{lb}}{\text{MW-hr}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times 1500\ \text{MW} \times 90\% \times \frac{8760\ \text{hours}}{\text{year}} = 6{,}711{,}255\ \text{tons/year}$$

Table 9.2-11 Recent Gas-Fired Power Plant Water Consumption

Gas Fired Plants

	Plant MW	Total Use (gpm)	Use (gpm/MW)	Use (rounded per Section 3.3) (gpm/MW)
Example 1	600	2603	4.34	4
Example 2	1611	10340	6.42	6
Example 3	514	3892	7.57	8

Table 9.2-12 Impacts Comparison Summary

Impact Category	Proposed Action Unit 3	Coal-Fired Generation	Gas-Fired Generation
Land Use	Small	Small	Small
Water Quality/Use	Small	Small to Moderate	Small to Moderate
Air Quality	Small	Moderate	Moderate
Ecological Resources	Small	Small	Small
Threatened and Endangered Species	Small	Small	Small
Human Health	Small	Small	Small
Socioeconomics	Small to Moderately Beneficial	Small to Moderately Beneficial	Small to Moderately Beneficial
Waste Management	Small	Moderate	Small
Aesthetics	Small	Small to Moderate	Small
Cultural Resources	Small	Small	Small
Accidents	Small	Small	Small

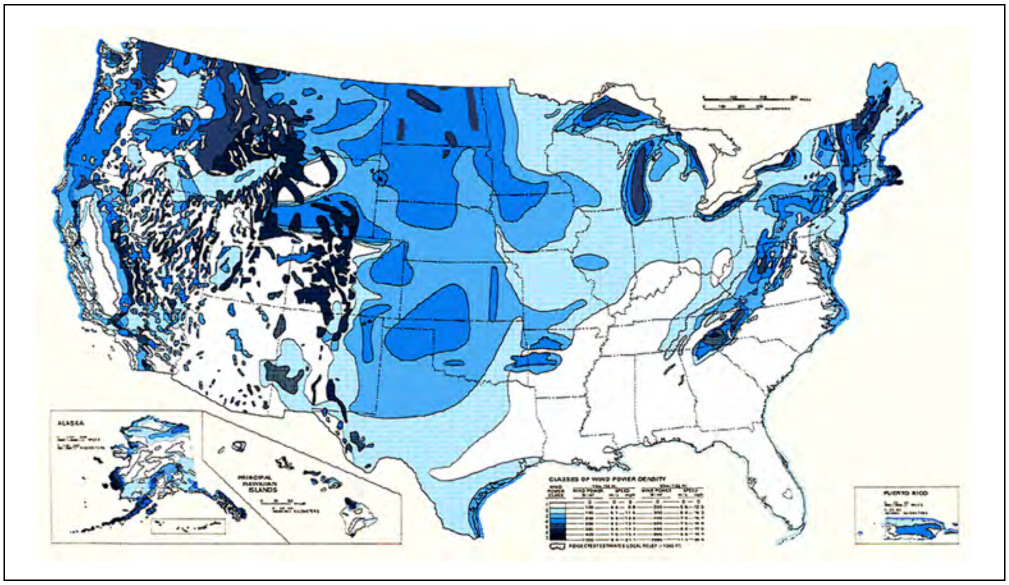
Notes:

SMALL: Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE: Environmental effects are sufficient to alter noticeably, but not destabilize, any important attribute of the resource.

LARGE: Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

Figure 9.2-1 United States Annual Average Wind Power



Source: Reference 13

9.3 Alternative Sites

Alternative sites are evaluated in ESP-ER Section 9.3 and finally resolved in FEIS Section 9.3. In accordance with 10 CFR 51.92(e)(3), and consistent with the ESP Finality on Environmental Issues in SECY-06-0220, no further discussion is required.

9.4 Alternative Plants and Transmission Systems

The information for this section is provided in ESP-ER Section 9.4, and the evaluation of system design alternatives for heat dissipation systems and circulating water systems is resolved in FEIS Section 8.2.

Dominion has conducted the IFIM study, as required in ESP Condition 3.I(2), and has further evaluated lake management operations as part of the study. Supplemental information on Lake Anna and watershed enhancements is provided in Section 5.10.1 that addresses specifically lake mitigating actions based on the results of the IFIM study.

At the time of the ESP-ER and based on an initial evaluation, the existing transmission lines were thought to have sufficient capacity for the total output of the existing and new units. On that basis, it was determined that there were no environmentally equivalent or more advantageous alternatives to "no action." However, it has now been determined that a new transmission line and other system reinforcements are required for grid reliability in association with the interconnection of Unit 3. Thus, the ESP-ER discussion is supplemented by the following information concerning the transmission lines.

PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study (Reference) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability in association with the interconnection of Unit 3. As part of the study, three existing corridors were considered for this new line: 1) NAPS-to-Ladysmith (east); 2) NAPS-to-Midlothian (south); and 3) NAPS-to-Morrisville (north) (see Figure 9.4-1). Only these corridors were considered because they would require no new land use and they already connect to NAPS at the 500 kV level. Construction of new 500 kV substations would be cost-prohibitive and require more land use.

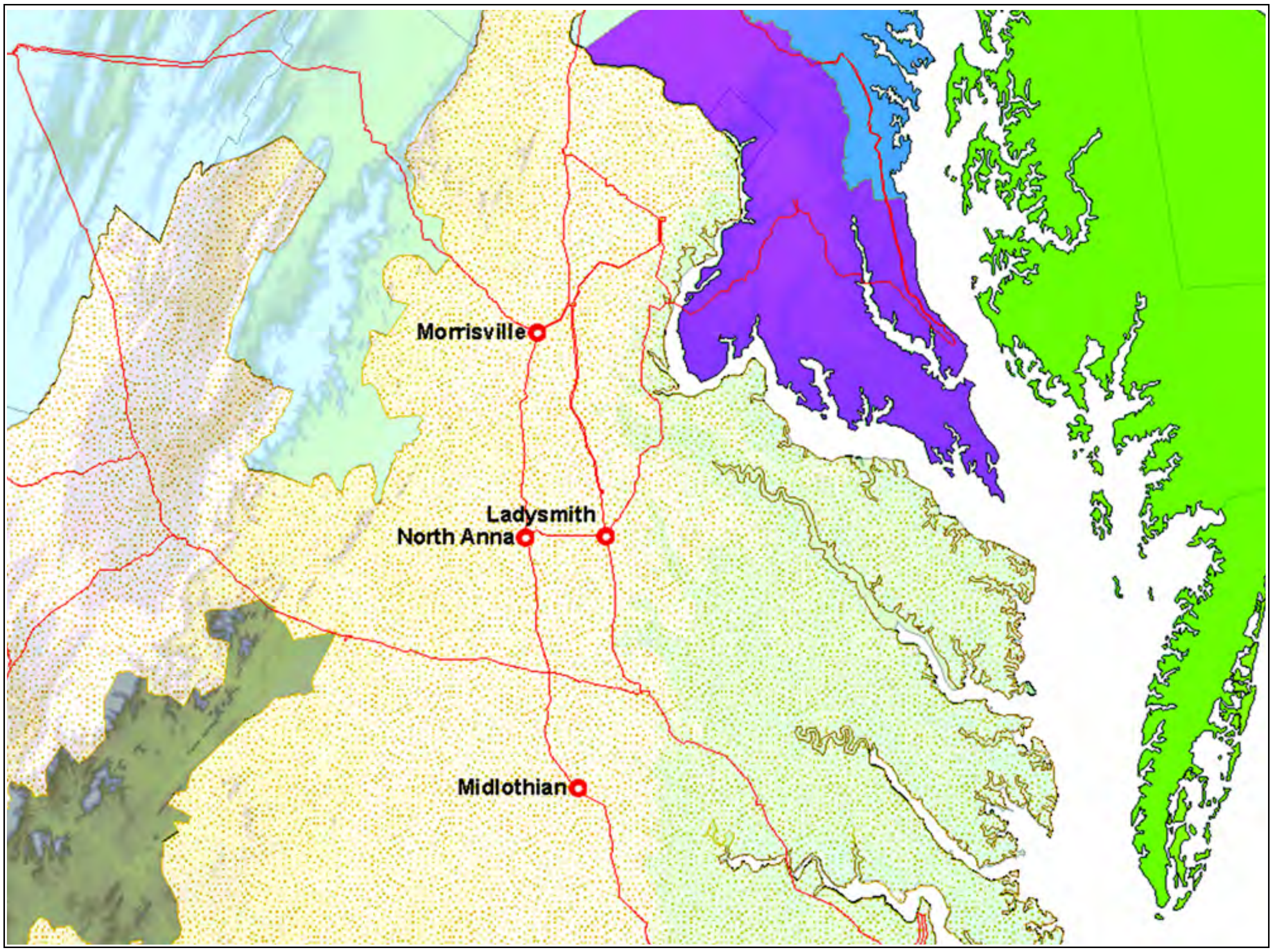
The PJM Study selected the NAPS-to-Ladysmith (east) corridor as the best alternative because it is sufficiently wide for a new 500 kV line, including the space needed for structure separation. Additionally, it is the shortest existing corridor. The NAPS-to-Midlothian (south) and NAPS-to-Morrisville (north) corridors are at least twice the length of the NAPS-to-Ladysmith corridor.

Because new transmission corridors are not required, the impacts of the new transmission line will be SMALL as described in Sections 4.1, 4.2, 4.3, 4.4, 5.1, and 5.6. New corridors for the new transmission line would pose greater impacts on land use, ecological systems, cultural resources, and local populations. Thus, the development of a new transmission corridor for installation of the new 500 kV line is not an environmentally preferable alternative.

Section 9.4 References

PJM System Planning Division, "PJM Generator Interconnection Q65 North Anna 500 kV (1570 MW Capacity/1594 Energy) Revised System Impact Study & Facilities Study Report Resulting from Necessary Studies," September 2013.

Figure 9.4-1 Existing Corridors or Routes Considered for the New North Anna Transmission Line



Chapter 10 Environmental Consequences of the Proposed Action

The potential environmental consequences of constructing and operating new units at the NAPS site are discussed in the ESP-ER Chapter 10 and associated issues are resolved in FEIS Section 10.1 and discussed in FEIS Sections 10.2, 10.4, and 10.5. Supplemental information is provided below.

10.1 Unavoidable Adverse Environmental Impacts

This section addresses the additional environmental impacts that have been identified in this ER.

10.1.1 Unavoidable Adverse Environmental Impacts During Construction

Table 10.1-1 lists the expected impacts from the construction of proposed Unit 3, and the mitigation measures that are practical to reduce these impacts. Those instances where adverse environmental impacts would remain after all reasonable means have been taken to avoid or mitigate them are identified in Table 10.1-1. A "Y", under the column labeled "Unavoidable Adverse Impacts" indicates that there are such impacts, and "N" indicates that the specified mitigation measures are sufficient to reduce the impacts to insignificant or small.

10.1.2 Unavoidable Adverse Environmental Impacts During Operation

Table 10.1-2 lists the expected impacts from the operation of proposed Unit 3, and the mitigation measures that are practical to reduce these impacts. Those instances, where adverse environmental impacts would remain after practical means to avoid or mitigate them have been applied, are identified in Table 10.1-2. A "Y" under the column labeled "Unavoidable Adverse Impacts" indicates that there are such impacts, and "N" indicates that the specified mitigation measures are sufficient to reduce the impacts to insignificant or small.

10.1.3 Summary of Adverse Environmental Impacts

As may be seen from Table 10.1-1 and Table 10.1-2, all the newly identified potential adverse environmental impacts associated with construction and operation of the proposed Unit 3 are reduced to insignificant or eliminated through the application of the listed mitigation measures, including those identified in the ESP-ER.

10.1.4 Irreversible and Irretrievable Commitment of Resources

Irreversible or irretrievable commitment of resources are addressed in Section 10.2.

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
The Site and Vicinity Section 4.1.1	Modifications to offsite roadways, bridges, and railway crossings to accommodate heavy hauls. – Additional land use outside NAPS site boundary.	Upon completion of the transports, temporary structures would be removed, interferences would be reinstalled, and disturbed areas would be restored back to their original condition or better.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	The new transmission line would be located in an existing corridor and constructed and maintained under practices and procedures applicable to the existing transmission lines.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which would protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property to its original condition and to the satisfaction of the property owner.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Transmission Line Rights-of-Way and Offsite Areas Sections 4.1.2 and 4.1.3	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to cultural or prehistoric resources.	Appropriate actions would be taken (e.g., stop work) following discovery of potential historic or archaeological resources.	N
Historic Properties and Cultural Resources Section 4.1.3	Upon completion of the transportation of large components disruptions to cultural resources including a historic train depot in Beaverdam, a ferry landing at the roll-off point, and the North Anna Battlefield are possible.	To the extent practicable, historic properties and cultural resources would be avoided. Mitigation measures for the impacts of the proposed large component transport route include the rehabilitation of land, removal of debris, and restoration of damaged property to its original condition or as close as possible.	N
Historic Properties and Cultural Resources Section 4.1.3	A newly discovered archaeological site lies within the NAPS-to-Ladysmith corridor. – Potential impacts to cultural or prehistoric resources.	Site will be flagged prior to and during construction activities to prevent disturbance.	N
Historic Properties and Cultural Resources Section 4.1.3	A newly discovered architectural resource is approximately 1/4 of a mile to the north of the NAPS-to-Ladysmith corridor. – Potential impacts to cultural resources.	The expected visual impact will be minimized by limiting the new tower heights to no greater than 20 ft. taller than existing towers. Depending on the final tower design, a photo simulation analysis may be required. The visual impact will be further minimized by selection of material colors that help the towers blend in to the natural surroundings.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	To the extent practicable, construction would avoid shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) would be consulted, and permits and approvals would be obtained as necessary.	N
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Soil disturbances would be controlled within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.	N
Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: (1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g. water bars and mulch); (2) properly removing and disposing debris left or caused by construction; and (3) restoring damaged property to its original condition and to the satisfaction of the property owner.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	The new transmission line would be located in an existing corridor and constructed and maintained under practices and procedures applicable to the existing transmission lines.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which would protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Land clearing necessary to accommodate the new transmission tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices, as well as applicable regulations.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Dust suppression techniques would be utilized and equipment maintenance employed to reduce airborne emissions	N
Section 4.3.1.4 Transportation of Large Components	The transportation of large components may potentially cause disruptions to wetlands adjacent to the proposed large component transport route include cutting, filling, and road improvements to these wetland areas.	To the extent practicable, impacts to shorelines and wetland areas would be avoided. Mitigation measures for wetlands and waterways located along the proposed large component transport route would include maintaining temporary erosion and sedimentation controls until permanent stabilization is achieved, removal of all debris, and rehabilitation of disturbed lands as close to their original condition as possible.	N
Socioeconomic Impacts Section 4.4	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts on public access to the area for recreational activities.	As a safety precaution, during installation of the transmission line across Lake Anna, access to the area would be temporarily restricted from recreational use.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Wetlands and Surface Water– Environmental Information Concerning Additional Property Appendix 4A	Additional property contiguous with the NAPS site will be utilized for Unit 3 project construction support. – Potential wetland impacts.	Impacts to wetlands within the additional property may be mitigated through preservation of onsite streams or purchasing offset credits from an approved mitigation bank.	N
Land Use – Environmental Information Concerning Additional Property Appendix 4A	Additional property contiguous with the NAPS site will be utilized for Unit 3 project construction support. – Potential land-use impacts.	The additional property area will be stabilized and facilities will be removed upon completion of the construction of Unit 3.	N

Table 10.1-2 Newly Identified Operations-Related Unavoidable Adverse Environmental Impacts

Category/COL ER Section	Operations-Related Issue/Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Water-Use Impacts Section 5.2.2	New wet cooling towers and a separate sanitary waste system would be added for Unit 3. – Potential for additional chemical effluents.	Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be governed by limits established in VPDES permit.	N
Water-Use Impacts Section 5.2.2	New wet cooling towers and a separate sanitary waste system would be added for Unit 3. – Potential for additional chemical effluents.	Operation of a dechlorination system to neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir. (Section 5.2.2)	N
Nonradioactive-Waste-System Impacts Section 5.5.1	Separate Unit 3 sanitary waste system would be added. – Potential for additional chemical effluents.	Sanitary wastes from the new sanitary system will be managed on site and disposed of off site in compliance with applicable laws, regulations, and permit conditions imposed by federal, Virginia, and local agencies (Section 5.5.1)	N
Nonradioactive-Waste-System Impacts Section 5.5.1	New wet cooling towers and a separate sanitary waste system would be added for Unit 3. – Potential for additional chemical effluents.	Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be governed by limits established in VPDES permit.	N
Mitigating Actions Based on the Results of the IFIM Study Section 5.10.1	The addition of Unit 3 to the existing NAPS site would create a further need on water resources of Lake Anna.	The normal pool level would be increased from Elevation 250.0 to 250.25 ft msl to reduce impacts on the ecology, wetland and recreation in Lake Anna and downstream.	N

10.2 Irreversible and Irretrievable Commitments of Resources

Irreversible and irretrievable commitments of resources are addressed in ESP-ER Section 10.2 and were resolved in FEIS Section 10.5, with the exception of an actual estimate of construction materials. The following supplemental information is provided to address the estimate of construction materials.

The irreversible and irretrievable commitments of material resources during the construction of proposed Unit 3 would be similar to that of any major construction project. Use of materials considered hazardous will be minimized, in accordance with safety regulations and practices. A Department of Energy report (Reference) provides the following new reactor construction estimates:

- 12,239 cubic yards of concrete and 3,107 tons of rebar for a reactor building
- 2,500,000 LF of cable for a reactor building
- 6,500,000 LF of cable for a single unit
- Up to 275,000 LF of piping (≥2.5") for a single 1300 MWe unit

The amounts of these materials are typical of other large power-generating facilities, such as hydroelectric and coal-fired power plants, that are constructed throughout the United States. The use of construction materials in the quantities associated with those expected for a nuclear power plant, while irreversible and irretrievable unless they are recycled at decommissioning, would be of small consequence, with respect to the availability of such resources.

The conclusion in the FEIS that the irreversible and irretrievable commitments would be of only small consequence will remain valid.

Section 10.2 References

Application of Advanced Construction Technologies to New Nuclear Power Plants, MPR-2610, Rev. 2, September 24, 2004, U.S. Department of Energy, Washington, D.C.

10.3 Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment

The relationship between short-term uses and long-term productivity of the human environment is addressed in ESP-ER Section 10.3. Further information on the benefits of the proposed action is provided in Chapter 8.

The principal short-term benefit of construction and operation of the proposed Unit 3 would be the production of electricity. The enhancement of regional productivity resulting from the electricity produced by Unit 3 would not be equaled by any other use of the NAPS site. In addition, most long-term impacts resulting from land-use preemption by plant structures would be eliminated by removing these structures or by converting them to other productive uses during decommissioning.

No new unavoidable adverse environmental impacts of construction and operation of the proposed Unit 3 have been identified to have significant impact on long-term productivity. Therefore, none of the adverse environmental impacts represent a long-term effect that would preclude any options for future use of the NAPS site.

10.4 Benefit – Cost Balance

The benefits and costs associated with construction and operation of proposed Unit 3 are summarized in Tables 10.4-1 and 10.4-2, respectively.

10.4.1 **Benefits**

The evaluation of monetary and non-monetary benefits of constructing and operating proposed Unit 3, including benefits related to tax revenues and to local and state economies, is provided in Chapter 8. These benefits are summarized in Table 10.4-1.

10.4.2 **Costs**

This section identifies both internal and external costs associated with the construction and operation of proposed Unit 3. The term "internal" generally refers to the monetary costs associated with a project, while the term "external" refers to non-monetary environmental costs of constructing and operating a new plant. These costs are summarized in Table 10.4-2.

Many of the cost attributes described in this section are detailed in Section 10.1 (Unavoidable Adverse Environmental Impacts), Section 10.2 (Irreversible and Irretrievable Commitments of Resources), and Section 10.3 (Relationship Between Short-term Uses and Long-term Productivity of the Human Environment) of the ESP-ER and this ER.

10.4.2.1 **Internal Costs**

This section describes the monetary costs of constructing and operating the proposed Unit 3. Internal costs include capital costs of the plant and transmission lines and operating costs, including staffing and maintenance (O&M), and fuel, as well as decommissioning costs.

10.4.2.1.1 **Construction**

The estimated cost of constructing Unit 3 is provided in COLA Part 1.

10.4.2.1.2 **Operation**

The U.S. Department of Energy study (Reference 2, Table 3.9, p. 111) estimates the annual O&M costs of a 1340 MWe ESBWR plant to be $74,178,482, which is calculated as $6.83 per MW-hr. This cost is expressed as unit of electric net generation, or megawatts electric, and reflects all costs that are incurred to operate and maintain the plant. Included in this cost are salaries and benefits for the plant staff, parts, material and equipment costs for maintaining plant equipment, fees, insurance, overhead costs, and short-term contract services.

Nuclear fuel cost and decommissioning cost are calculated separately. The Organisation for Economic Co-Operation and Development (OECD) Study (Reference 1, Table 3.9, p. 44) estimates that the average fuel cost for a nuclear generating plant is $4.64 per MW-hr at a 5 percent discount rate. A decommissioning cost estimate is provided in Part 1 of this COL Application.

10.4.2.2 **External Costs**

This section describes the external (non-monetary) environmental and social costs of constructing and operating proposed Unit 3. The environmental effects of construction and operation of proposed Unit 3 are described in Section 10.1 and ESP-ER Section 10.1. Details are also provided in Tables 10.1-1 and 10.1-2 of the ESP-ER and this ER regarding potential mitigation measures for each unavoidable adverse impact related to a construction or operation activity.

10.4.2.2.1 **Land Use**

Approximately 133 acres will be affected by the construction of proposed Unit 3 as a result of permanent facilities. An additional 160 acres, including approximately 111 acres outside the EAB on the additional property, will be disturbed on a short-term basis as a result of temporary activities and construction of temporary facilities and laydown areas. Clearing and removal of trees growing within the NAPS site will be required. Loss of land use is an external cost of the construction of Unit 3. A detailed description of land use impacts is provided in Section 4.1 and ESP-ER Section 4.1.

10.4.2.2.2 **Hydrological and Water Use**

Section 4.2 and ESP-ER Sections 4.2 and 5.2 describe hydrologic alterations for construction and operation. As discussed in these sections, there are some costs associated with providing water for various needs during construction and operation. The majority of water used for Unit 3 operations will be surface water drawn from the North Anna Reservoir. As resolved in FEIS Section 5.3.2, this water use represents only a small fraction of available water even at low flow conditions. The FEIS concluded that the impact of Unit 3 operation on downstream water users would be SMALL for most and MODERATE for drought years. There are also costs associated with groundwater consumption. The effects related to groundwater use are described as small (see ESP-ER Sections 2.3.2.2 and 5.2, and FEIS Section 2.6.2). Use of groundwater by the site will not affect off-site users in terms of either water availability or water quality.

Relatively small levels of nonradioactive and radioactive effluents will be introduced into the lake. Water quality impacts of chemical effluents discharged during Unit 3 operations are discussed in Section 5.2.2 and will be SMALL. FEIS Section 5.9.3.3 resolved that effects upon humans as a result of liquid radiological effluents released from new units would be SMALL. Cooling water blowdown that discharges to the North Anna Reservoir results in a thermal plume. FEIS Section 5.4.2.4 resolved that effects of a thermal plume on Lake Anna would be SMALL and localized.

10.4.2.2.3 **Terrestrial and Aquatic Biology**

Ecological effects, related to plant construction and operation, are described in Section 4.3 and in ESP-ER Sections 4.3 and 5.3, respectively. Some cost due to mortality of wildlife during construction is anticipated. These losses are not expected to be large enough to affect the long term stability of wildlife populations. FEIS Section 5.4.1 resolved that effects on terrestrial ecosystems would be SMALL. The cooling system, in addition to the makeup water intake structures, is designed to reduce loss of aquatic biota as a result of impingement and entrainment. The construction of the new intake structure will result in only minor and temporary effects to aquatic biology. In FEIS Section 5.4.2.8, the NRC determined that effects upon aquatic ecosystems as a result of operations of new nuclear units would be SMALL.

Relatively small amounts of air emissions from gas turbine and diesel generators, auxiliary boilers and equipment, and vehicles are generated from nuclear power plant operation.

Cooling tower drift deposits some salt on the surrounding vicinity, but the level is unlikely to result in any measurable impact on plants and vegetation. The Unit 3 cooling towers are designed to abate atmospheric vapor plume produced.

Small amounts of hazardous effluents are components of the Unit 3 plant discharges into Lake Anna. Relatively small amounts of hazardous wastes will be generated that need to be managed and disposed of pursuant to the Resource Conservation and Recovery Act (RCRA). Section 3.6 and ESP-ER Section 3.6 discuss nonradioactive waste systems.

10.4.2.2.4 **Hazardous and Radioactive Emissions, Effluents, and Wastes**

Operation of proposed Unit 3 will include minor radioactive air emissions to the atmosphere. Relatively small levels of radioactive effluents will be generated and discharged into Lake Anna.

Low-Level radioactive wastes will be generated that need to be stored, treated, and disposed of in a licensed landfill. High-level radioactive spent fuel will be generated that will need to be isolated (or possibly reprocessed) in a geological repository for thousands or tens of thousands of years. FSAR Chapter 11 describes the radioactive waste management systems.

10.4.2.2.5 **Materials, Energy, and Uranium**

Construction of proposed Unit 3 will result in an irreversible and irretrievable commitment of materials and energy (see Section 10.2 and ESP-ER Section 10.2). Operation of the new reactor will contribute to the depletion of uranium.

10.4.2.2.6 **Potential for Nuclear Accident**

The potential effects of various types of nuclear accidents are described in FEIS Section 5.10. In Section 5.10.3, the NRC concluded that the potential environmental impacts from a postulated accident from the operation of two additional advanced light water reactor (LWR) nuclear units at NAPS would be SMALL.

10.4.2.2.7 **Socioeconomic Costs**

Sections 4.4 and 5.8 and ESP-ER Sections 4.4 and 5.8 describe socioeconomic costs related to construction and operation of new units at NAPS. Additional public and social services may be required to meet the demands of people moving into the area during construction and operation of the new unit at NAPS. Increased tax revenues from those individuals and from NAPS should offset these costs.

10.4.3 **Summary**

As described in Section 8.4, there is a growing baseload demand and growing baseload supply shortfall for the region of interest. Without additional capacity, Dominion's electricity network will fail to maintain an adequate power reserve margin, will fail to meet its public service obligations to provide adequate power, and will jeopardize Dominion's commitment to provide power to other electric service providers within the region. Proposed Unit 3 will help meet growing baseload shortfall in the region by supplying an average annual electrical-energy generation of about 12,000,000 MW-hrs.

Proposed Unit 3 is designed to generate electricity that results in significant reduction in CO_2 emissions with respect to comparably-sized coal- or gas-fired alternatives. As described in this section, proposed Unit 3 would also have important strategic implications in terms of lessening the dependence of the U.S. on foreign energy supplies, and their potential interruption, as well as vulnerability to volatile price changes or political whims. While the additional direct and indirect creation of jobs places some temporary burden on local services and infrastructure, the annual taxes and revenue generated by the new workers contribute to the local economy and fuels future growth.

On balance, the benefits of the new plant would significantly outweigh the economic, environmental, and social costs.

Section 10.4 References

1. Organisation for Economic Co-operation and Development (OECD) and Nuclear Energy Agency, "Projected Costs of Generating Electricity, 2005 Update," In Proceedings of GLOBAL 2005, report, October 9-13, 2005.

2. U.S. Department of Energy, "Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs," Volume 1, May 27, 2004.

Table 10.4-1 Monetary and Non-Monetary Benefits of Proposed Unit 3

Category of Benefit	Description of Benefit
Net Electrical Generating Benefits	
Net Generating Capacity	~1,500 MWe
Electricity Generated	~12,000,000 MW-hrs (operating at 90% capacity)
Taxes and Revenue During Plant Operation Period (Transfer Payments – Not Independent Benefits)	
Annual State Taxes	NAPS Unit 3 pays $14.8 million.
Annual Property Taxes	NAPS Unit 3 pays $3.5 million.
Annual Sales Taxes	NAPS Unit 3 pays $24.2 million.
Effects on Regional Productivity	
Land Use	Co-location of additional generating capacity on land already designated as industrial use and dedicated to power generation results in no acres of land-use conversion, thus leaving other land for continued current use or conversion for other projects that would benefit the region's productivity.
Hydrological	Co-location of additional generating capacity on existing water source already used for power generation eliminates impacts to other water resources and watersheds. Annual minimum Lake Anna elevation will average 0.26 feet lower[a] than existing conditions and 0.31 acres of non-tidal wetlands and 757 linear feet of stream bed are expected to be permanently disturbed for construction of Unit 3. Thus, the region's existing water resources and watersheds would remain largely as-is, which would conserve the resource or make it available for other uses deemed necessary for the region's productivity.
Construction Workers	Approximately 2,500 workers create an incremental increase of 1,550 indirect jobs within the region for the duration of the construction period. The increase in population would result in positive impacts to the local economy. Peak construction workforce is estimated at 4,100.
Operational Workers	500 operations workers would create an additional 1,035 indirect permanent jobs within the region for a total of approximately 1,500 additional jobs, for at least 40 years of plant operations. These people and their families would reside in the area, purchase homes, goods and services, and pay property and sales taxes, increasing the economic base of the region.

Table 10.4-1 Monetary and Non-Monetary Benefits of Proposed Unit 3

Category of Benefit	Description of Benefit
Socioeconomics	Increased tax revenue from NAPS payments as well as property and sales taxes paid by workers supports improvements, expansions, or additions to public infrastructure and social services, making the region attractive for future growth and development. Influx of money from workers' wages spurs future growth and development in the private sector. Influx of money from workers' wages will be in addition to current tourist dollars because Lake Anna recreational opportunities will not be adversely affected by Unit 3. (The annual minimum Lake Anna elevation will average 0.26 feet[a] lower than existing conditions and there will be indistinguishable biological impacts to the general aquatic community of the North Anna River and the striped bass spawning and early rearing areas of the Pamunkey River.)
Technical and Other Non-Monetary Benefits	
Fuel Diversity	Reduces exposure to supply and price risk associated with reliance on any single fuel source.
Price Volatility	Dampens potential for fuel price volatility.
Fossil Fuel Supplies	Offsets usage of finite fossil fuel supplies.
Electrical Reliability	Enhances electrical reliability.
Emissions Reduction	Significant beneficial impact in terms of avoidance of air emissions.
Carbon Dioxide Emissions	Baseload generation with no carbon dioxide emissions.
Wastes	Compared with fossil-fueled plants, nuclear plants produce less nonradioactive waste products. A comparable coal-fired plant would generate 5.6 to 31.9 tons of ash per hour.

a. The 0.26 ft difference between the annual minimum lake elevations with Unit 3 in operation and the existing condition was a prediction from the water budget model described in the ESP, which simulated lake levels from October 1978 to October 2003. The model has been extended to October 2007 to evaluate the 3-inch pool level rise mitigating action based on results of the IFIM study. The 0.26 ft value from the ESP model would be conservative if the IFIM lake mitigating action is adopted when Unit 3 begins operation because, with the potential 3-inch increase in normal pool level, the difference in the average annual minimum lake levels from the existing condition would be less than 0.26 ft.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Internal Costs	
Construction (Overnight Cost)	$8,206 per kW
Operation	$6.83 per MW-hr for O&M $4.64 per MW-hr for fuel cycle
Decommissioning (NRC Minimum)	$672,826,269
External Costs	
Land and Land Use	SMALL. Unit 3 occupies approximately 133 acres of the approximately 1043 acres (422 ha.) of the existing NAPS site. Unit 3 would require no acres for new transmission corridors (existing transmission corridor would be used for the new transmission line).
Hydrological and Water Use	SMALL for most years; MODERATE during drought years. There are some costs associated with providing water for various needs during construction and operation. Cooling water would be taken from Lake Anna at the rate of 15,376 gpm (Maximum Water Conservation (MWC) mode) or 22,260 gpm (Energy Conservation Mode (EC) mode.) The blowdown return to the WHTF would be 3,837 gpm in the MWC mode and 5,558 gpm in the EC mode. The cooling water consumption rate (withdrawal minus blowdown) would be 11,532 gpm in the MWC mode and 16,695 gpm in the EC mode. The effect of consumption of cooling water is relatively small. Small concentrations of hazardous chemicals and radioactive effluents would be introduced into Lake Anna. Concentrations of chemicals and solids would be below applicable VPDES permit limits at the point of compliance. Blowdown discharge would be at a maximum temperature of 100°F and at a rate of 12.4 cfs. The small increase in velocity and volume would not increase scour or erosion problems. There would be no perceptible impact on the water temperature (estimated temperature increase attributable to Unit 3 would be a maximum of one-tenth of a degree Fahrenheit) or stratification in Lake Anna. Annual minimum lake elevations with Unit 3 will be 0.01 to 0.89 feet lower than existing conditions, with this difference averaging 0.26 feet.[a] Relatively small levels of hazardous and/or radioactive effluents introduced into Lake Anna. Thermal plume resulting from cooling water blowdown discharged to Lake Anna. The effect of consumption of cooling water is relatively small.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Terrestrial and Aquatic Species	SMALL. Some cost to wildlife due to mortality during construction operations is anticipated. However, these costs do not affect long term wildlife populations. Construction activities would impact North Anna Reservoir due to increased turbidity and the potential for sedimentation as a result of the modification of the cofferdam. Construction would permanently disturb approximately 0.31 acres of non-tidal wetlands and 757 linear feet of ephemeral streams. No federal or state-listed protected fish species occur in Lake Anna, its tributary streams, or North Anna River. No critical habitats for aquatic or terrestrial species occur in the area. Wildlife mortality, including aquatic biota, during operations is expected to be minimal. The addition of Unit 3 would increase total impingement for three units by <3%. A new station water system for Unit 3 in combination with the current once-through system for Units 1 and 2 would remove approximately the following portions of Lake Anna's standing crop by impingement: 0.33% by weight of gizzard shad annually, 3.9% of black crappie, just over 1.4% of yellow perch, 0.02% of bluegill, and 0.1% of white perch. The addition of Unit 3 would increase total estimated entrainment by <3%. The Lake Anna fishes are prolific, exhibit high reproductive potential, and have compensatory responses that would offset these losses. Lake Anna minimal average lake level during non-drought years would be 248.6 ft msl. There will be no measurable biological impacts to the aquatic community of the North Anna River or the striped bass spawning and early rearing areas of the Pamunkey River from reductions in freshwater inflows due to the additional evaporative water loss from a new Unit 3. The increase in discharge flow would range from 0.2% (the MWC mode maximum blowdown rate of 3,844 gpm added to two-unit, open-cycle flow of approximately 1,900,000 gpm) to 0.6% (maximum blowdown rate of 5,565 gpm added to one-unit, open-cycle flow of approximately 950,000 gpm). Discharge flow would range from 3,844 gpm (Units 1 and 2 offline; Unit 3 operating and discharging blowdown at maximum MWC mode rate) to 1,905,565 gpm (Units 1, 2, and 3 operating; Unit 3 discharging blowdown at maximum rate). Blowdown discharge's velocity would have negligible impact. Concentrations of chemicals and solids would be below applicable VPDES permit limits at the point of compliance and would have a small impact on aquatic ecology.

(continued)

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Terrestrial and Aquatic Species *(continued)*	There would be no perceptible impact on the temperature (estimated temperature increase attributable to Unit 3 would be a maximum of one-tenth of a degree Fahrenheit at the end of the discharge canal) and there would be no impact on aquatic communities of Lake Anna.
Radioactive Effluents and Emissions, Radioactive Dose	SMALL. Radioactive waste is generated. The plant would produce radioactive air emissions. Low concentrations of radioactive liquid effluents are introduced into Lake Anna. The estimated radioactive doses from all sources would be as follows: • occupational dose: 84.5 person-rem/yr • total body dose to the MEI: 5.5 mrem/yr • collective total body dose to population within 50 miles: 5.3 person-rem/yr • dose to biota: 0.5 to 18 mrad/yr (liquid), 3.4 mrad/yr (gaseous)
Hazardous and Radioactive Waste	SMALL. Storage, treatment, and disposal of high-level radioactive spent nuclear fuel would occur, with a commitment of underground geological resources for disposal of radioactive spent fuel. Generation of 16,742 ft^3/yr of solid radioactive wastes with activity of 1,718 Curies would be expected. Generation of 15 ft^3/yr mixed liquid waste and 5 ft^3/yr mixed solid waste, and maximum generation of 30 ft^3/yr mixed liquid waste and 10 ft^3/yr of mixed solid waste would also be expected.
Air Emissions	SMALL. Air emissions from gas turbine and diesel generators, auxiliary boilers and equipment, and vehicles that have a small impact on workers and local residents would occur. Cooling tower drift would deposit some salt in the immediate vicinity, but the level is unlikely to result in any measurable impact on vegetation. Cooling tower atmospheric plume discharge would be abated by cooling tower design.
Meteorological	SMALL. Heated air from Unit 3's cooling towers would not increase the atmospheric and ground temperature beyond the NAPS site boundary. Blowdown from Unit 3 to the WHTF would lead to negligible additional steam fog. Cooling tower atmospheric plume discharge would be abated by cooling tower design.
Noise	SMALL. Construction activities would have a noise level of 60–80 dBA at 120 m (400 ft) from the Unit 3 construction site. Noise levels from cooling tower operation will be confirmed to be < 65 dBA at the EAB. Other noises would be as they are currently for Units 1 and 2.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Non-Radiological Human Health	SMALL. Estimated temperature increase attributable to Unit 3 would be a maximum of one-tenth of a degree Fahrenheit at the end of the discharge canal, which would dissipate to an undetectable level within a short distance of travel in the WHTF. Further, the blowdown from the Unit 3 wet cooling towers would contain a biocide. Therefore, Unit 3 would not contribute to an environment conducive to the growth of thermophilic organisms in the WHTF. Unit 3's sewage would be treated in a new sewage treatment facility and the discharge would meet local and state regulations for effluent quality in accordance with the VPDES permit. Noise levels from cooling tower operation will be confirmed to be < 65 dBA at the EAB.
Socioeconomics	SMALL, with the exception that transportation impacts would be MODERATE. Peak construction workforce is estimated at 2,500 to 4,100. The temporary in-migration to the region of interest is estimated to be 20% of the construction workforce. Traffic during peak employment of 4,100 construction workers would be divided into two 10-hour shifts, and the current existing workforce of approximately 1,000 would continue to be divided into two 12-hour shifts, so the shift changes would be staggered. Using an average of 1.8 persons per vehicle, the number of vehicles attributable to NAPS during the peak hour of traffic (shift change for construction workforce) would be about 2,300 vehicles and the total traffic attributable to NAPS would be about 2,850 vehicles per day. This increase in traffic could increase congestion from a Level of Service (LOS) of B to a LOS of D, even with the application of mitigation measures. During outages with an additional 1,000 outage workers on two 12-hour shifts that also would be staggered, the number of vehicles attributable to NAPS during the peak hour of traffic would continue to be the 2,300 vehicles associated with the construction workforce shift change. However, the total traffic attributable to NAPS during an outage day would be about 3,400 vehicles (assuming 1.8 persons per vehicle for the outage workers as well). Operation of Unit 3 would require approximately 500 workers or an increase in the population in the region of interest by 2,000, assuming each new employee represents a family of four and relocates to the region. This increased population due to the operations workers and their families would be a small fraction of the expected population growth in the vicinity and region around the NAPS site, therefore no unforeseen demands for educational, medical, fire, or police services would result from the operation of Unit 3. The visual impact study indicates that the impact to the public from Unit 3 would be similar to the visual impact from the existing units, therefore small.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Materials, Energy, and Uranium	SMALL. There would be irreversible and irretrievable commitments of materials and energy, including uranium. Construction of Unit 3 would require an estimated 12,239 cubic yards of concrete for the Reactor Building, 3,107 tons of rebar for the Reactor Building, 6,500,000 linear feet of cable, and 275,000 linear feet of piping greater than 2.5 inches in diameter.
Decommissioning	SMALL. The estimated radioactive doses would be substantially less than the estimated doses for operations.

a. The annual minimum lake elevation with Unit 3 in operation and the differences from the existing condition were predictions of the water budget model described in the ESP, which simulated lake levels from October 1978 to October 2003. The model has been extended to October 2007 to evaluate the 3-inch pool level rise mitigating action based on results of the IFIM study. These values from the ESP model would be conservative if the IFIM lake mitigating action is adopted when Unit 3 begins operation because, with the potential 3-inch increase in normal pool level, the difference in the average annual minimum lake levels from the existing condition would be less than 0.26 ft and the non-drought year average minimum lake level would be higher than Elevation 248.6 ft msl.

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North Anna 3 Combined License Application

Part 4: Technical Specifications

Revision 7

June 2016

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REVISION SUMMARY

Revision 7

Section	Changes	Reason for Change
B 2.1.2, ..B 3.4.4, ..B 3.7.2	Adjusted formatting	Consistency with TSTF-GG-05-01

Revision 6

Section	Changes	Reason for Change
Global	Adjusted content alignment; revised/added/deleted borders and separator rules; added missing continuation headings, adjusted page breaks; conformed case; no change bars	Editorial; DCD R10
1.4	Changed page header from “1.1” to “1.4”	Editorial
3.1.7	Added period at end of APPLICABILITY	DCD R10
3.3.1.2	Added colon after APPLICABILITY	DCD R10
3.3.1.3 & 3.3.1.5	Added colon after APPLICABILITY; added period at end of statement	DCD R10
3.3.3.2	Added periods at end of C.2.1 & C.2.2	DCD R10
3.3.5.2	Changed page header from “ESSC” to “ECCS”	Editorial
3.3.5.3	Changed Surveillance Requirements from “NOTES” to “NOTE”	DCD R10
3.3.5.4	Moved Surveillance Requirements note above table	DCD R10
3.3.8.1	Added colon after APPLICABILITY; added period at end of statement; added period at end of SR 3.3.8.1.1	DCD R10
3.4.1	Added period after second Condition B statement	DCD R10
3.5.3	Changed SR 3.5.3.3 & SR 3.5.3.5 from “NOTE” to “NOTES”	DCD R10
3.5.5	Added period to B.2	DCD R10
3.6.3.1	Changed SR 3.6.3.1.3 from “NOTES” to “NOTE”	DCD R10
3.7.5	Added period to SR 3.7.5.2	DCD R10
3.9.5	Changed “A.1.1” to “A.1”	DCD R10

Revision 6 *(continued)*

Section	Changes	Reason for Change
3.10.3 & 3.10.4	Added period to A.1 Note 1	DCD R10
5.5.6	Changed end of item b. from "...; and" to period	Editorial
B 3.1.2	Editorial	DCD R10
B 3.1.3	Editorial and typographic corrections	DCD R10
B 3.1.5	Editorial	DCD R10
B 3.3.1.3	Editorial	DCD R10
B 3.3.3.2	Changed page numbers and added revision number	Editorial
B 3.4.3 & B 3.3.5.4	Changed "REFERENCE" to "REFERENCES"	DCD R10
B 3.3.5.1	Corrected numbering of references	Editorial
B 3.3.5.2	Editorial	DCD R10
B 3.3.7.2	Editorial	DCD R10
B 3.4.4	Editorial	DCD R10
B 3.5.5	Editorial	DCD R10
B 3.6.2.2	Editorial	DCD R10
Table B 3.7.2-1	Deleted "No" from Group 2, N-DCIS	DCD R10
B 3.7.6	Editorial	DCD R10
B 3.8.1	Editorial	DCD R10
B 3.9.1	Editorial	DCD R10
B 3.9.2	Editorial	DCD R10
B 3.10.3 & B 3.10.4	Changed "Control Room Withdrawal" to "Control Rod Withdrawal"	DCD R10
B 3.10.8	Changed title from "SHUTDOWN MARGIN - (SDM) Test Refueling" to "SHUTDOWN MARGIN (SDM) Test - Refueling"	DCD R10

Revision 5

Section	Changes	Reason for Change
5.6.4.b.1, B 3.4.4, Reference 6	Changed “Revision 5, February 2011” to “Revision 6, November 2013”	Topical Report updated

Revision 4

Section	Changes	Reason for Change
Introduction	Deleted reference to COL Holder items	The term “COL-Holder” was removed from the DCD/GTS and the former COL Holder items moved to Table 16.0-1-A for COL applicant items.
Introduction Item 3 (deleted)	Deleted. Following items have been renumbered; deleted COL Items 3.3.3.2-1 and 5.6.6.1.	PAM Instrumentation has been added to the GTS in Section 3.3.3.2. DCD/GTS text and DCD COL items associated with this PAM Instrumentation item, which required bracketed information for plant-specific TS, have been deleted. See Fermi R-COLA RAI EF3 RAI Q16-1 response.
Introduction Item 4 (previous Item 5)	Changed COL Item 16.0-2-H 1.1-1 to 16.0-1-A 1.1-1. Changed COL Item 16.0-2-H 5.6.4-1 to 16.0-1-A 5.6.4-1.	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
	Revised Plant-Specific TS action to add approved PTLR methodology document to TS 5.6.4.	The PTLR has been issued and approved by NRC.
	Revised Justification to add NEDC 33441P.	The PTLR has been issued and approved by NRC.
Introduction Item 5 (previous Item 6)	Corrected typo	Typo
Introduction Item 18 (previous Item 19)	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.

Revision 4 *(continued)*

Section	Changes	Reason for Change
Previous Introduction Item 22	Deleted	Allowable Values no longer in GTS; NEDE-33304P addresses AVs. COL Items associated with AVs have been deleted since they are no longer required to be included in the GTS.
Previous Introduction Item 23	Deleted	Minimum SRNM count rate is now included in the GTS and no longer a COL Item. COL Item associated with SRNM Count Rate has been deleted because it is now included in the GTS.
Introduction Item19 (previous Item 22)	Deleted charger rated current	COL item revised in DCD
	Deleted last sentence of Justification	Battery charger current now included in SR 3.8.1.2
	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
Introduction Item 20 (previous Item 23)	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
	Deleted COL Item 3.8.1-2	COL item deleted from DCD
	Revised GTS, Plant-Specific TS, and Justification text to reflect DCD changes regarding the method to verify that the battery is fully charged	Method to verify a fully changed battery changed to be based on float current
	Deleted battery model from Justification	Changed to battery manufacturer’s recommendations
Previous Introduction Item 24	Deleted	Optional test and COL item deleted from DCD

Revision 4 *(continued)*

Section	Changes	Reason for Change
Introduction Item 21 (previous Item 25)	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
	Revised GTS discussion to reflect revised COL item requirement regarding bracketed information	Bracketed information for COL item revised in DCD
	Deleted battery model from Justification	Revised to refer only to battery manufacturer
Introduction Item 22 (previously Item 26)	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
	Revised GTS and Justification discussion to reflect revised COL item requirement regarding bracketed information	Bracketed information for COL item revised in DCD
	Deleted battery model from Justification	Revised to refer only to battery manufacturer
Introduction Item 23 (previously Item 27)	Changed COL Item STD COL 16.0-2-H to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
	Revised Plant-Specific TS and Justification discussions to reflect that the GEH Setpoint Methodology (NEDE-3304P-A) has been approved by NRC)	Bracketed information for COL item revised in DCD
Previous Introduction Item 28	Deleted	The CRHAVS EFU Differential Pressure is now included in the DCD and the COL item has been deleted.
Technical Specifications	Updated to match DCD Chapter 16 Rev. 9 for the incorporated by reference sections. These changes are not identified by revision bars because the information is incorporated by reference.	DCD R9

Revision 4 *(continued)*

Section	Changes	Reason for Change
TS 1.1, Pressure and Temperature Limits Reports (PTLR)	Changed COL Item STD COL 16.0-2-H 1.1-1 to STD COL 16.0-1-A 1.1-1	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS SR 3.1.5.1	Changed COL Item STD COL 16.0-2-H 3.1.5-1 to STD COL 16.0-1-A 3.1.5-1	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS 3.4.4; SR 3.4.4.1 thru SR 3.4.4.5	Changed COL Item STD COL 16.0-2-A 3.4.4-1 to STD COL 16.0-1-A 3.4.4-1	COL item number revised in DCD
TS 3.7.2 RA B.2	Changed COL Item STD COL 16.0-1-A to NAPS COL 16.0-1-A	Typographical error
SR 3.8.1.2	Changed COL Item STD COL 16.0-2-A to STD COL 16.0-1-A	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS SR 3.8.1.2	Changed COL Item STD COL 16.0-2-H 3.8.1-1 to STD COL 16.0-1-A 3.8.1-1	COL item number revised in DCD
TS 3.8.3 Condition A	Changed COL Item STD COL 16.0-2-H 3.8.3-3 to STD COL 16.0-1-A 3.8.3-3	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS 3.8.3 Condition A; RA A.3; SR 3.8.3.2, SR 3.8.3.5	Changed bracketed float voltage from 2.11 V to 2.09 V	Changed float voltage to agree with EF3 because NA3 will use the same battery as EF3
TS 3.8.3 Conditions B, C & G (previous Condition F)	Added COL Item 16.0-1-A 3.8.3-1	DCD R9
TS 3.8.3 Condition B, RA B.2, Condition C, RA C.2, Condition G (previous Condition F)	Removed brackets from “float current ≤ 30 amps”	Retained DCD Rev. 9 value to agree with EF3 because NA3 will use the same battery as EF3
TS SR 3.8.3.1	Changed COL Item STD COL 16.0-2-H 3.8.3-1 to STD COL 16.0-1-A 3.8.3-1	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.

Revision 4 *(continued)*

Section	Changes	Reason for Change
TS SR 3.8.3.2, 3.8.3.5	Changed COL Item STD COL 16.0-2-A 3.8.3-3 to STD COL 16.0-1-A 3.8.3-3	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS SR 3.8.3.6	Changed COL Item STD COL 16.0-2-A 3.8.3-4 to STD COL 16.0-1-A 3.8.3-4	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS SR 3.9.5.2	Changed COL Item STD COL 16.0-2-H 3.9.5-1 to STD COL 16.0-1-A 3.9.5-1	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A.
TS 4.1	Revised Site Location description	To match the description used for the US-APWR TS
TS 5.3.1	Revised description regarding conformance with RG 1.8, Revision 3 and changed COL Item STD COL 16.0-1-A to NAPS COL 16.0-1-A	To be consistent with wording in US-APWR TS
TS 5.5.10.a	Changed 2.15 V to 2.13 V	Changed float voltage to agree with EF3 because NA3 will use the same battery as EF3
TA 5.5.11.b	Changed COL Item STD COL 16.0-2-H 5.5.11-1 to STD COL 16.0-1-A 5.5.11-1	The term “COL Holder” has been deleted from the DCD/GTS and the former COL Holder items moved to DCD Table 16.0-1-A. This change addresses SER Open Item 16.0-1.
	Replaced bracketed information for NEDE-33304P-A	GEH Setpoint Methodology (NEDE-33304P-1-A)
TS 5.6.4	Changed COL Item STD COL 16.0-2-A 5.6.4-1 to STD COL 16.0-1-A 5.6.4-1	DCD R9 This change addresses SER Open Item 16.0-1.
	Replaced bracketed information for PTLR methodology with NEDC-3341P	PTLR methodology (NEDC-33441P) has been approved by the NRC.

Revision 4 *(continued)*

Section	Changes	Reason for Change
Bases	Updated to match DCD Appendix 16B for incorporated-by-reference content. Change bars are not applied for such content.	DCD R9
Bases SR 3.1.5.1, 3.8.1 Background, SR 3.8.1.1, SR 3.8.1.2, 3.8.3 Background, 3.8.3 Actions A.1, A.2 and A.3, 3.8.3 Actions B.1, B.2, C.1 and C.2 (two places), 3.8.3 Action G.1, SR 3.8.3.1 (two places), SR 3.8.3.2 and SR 3.8.3.5, SR 3.8.3.6, 3.9.5 LCO, SR 3.9.5.1 and SR 3.9.5.2	Changed COL Item “STD COL 16.0-2-H” to STD COL 16.0-1-A”	The term “COL-Holder” has been removes from the DCD/GTS Bases, and the former COL-Holder items moved to Table 16.0-1-A for COL Applicant Items.
Bases 3.4.4 Background, 3.4.4 LCO (three places) SR 3.4.4.3, SR 3.4.4.4, and SR 3.4.4.5 (two places)	Changed COL Item “STD COL 16.0-2-A” to STD COL 16.0-1-A”	COL Item number revised in DCD
Bases 3.4.4 References	Changed COL Item “STD COL 16.0-1-A 3.4.4-3” to “CWR COL 16.0-1-A 3.4.4-3”	EF3 has a typo in reference 6, “February” is misspelled
	Replaced bracketed Reference 6 for PTLR topical report with NEDC-33441P	NRC has approved NEDC-33441P
Bases SR 3.8.1.1	Changed bracketed minimum float voltage from “2.21 Vpc or 268.8 V” to “2.22 Vpc or 266.4 V”	Based on battery manufacturer’s recommendations
Bases SR 3.8.1.2	Changed bracketed battery charger test duration from “≥ 8 hours” to “8 hours”	Based on battery manufacturer’s recommendations
Bases 3.8.3 Background, SR 3.8.3.2 and SR 3.8.3.5	Revised bracketed battery cell parameters related to battery OPERABILITY including nominal specific gravity (1.240), fully charged open circuit battery voltage (249.6 V for 120 cell battery, i.e., cell voltage of 2.07 to 2.09 Vpc), optimum long-term float voltage (2.22 to 2.24 Vpc), nominal cell float voltage (2.23 Vpc), and total float voltage output (267.6 V).	Based on battery manufacturer’s recommendations
Bases 3.8.3 Background	Changed “Ref. 2” to “Ref. 1” in last sentence of last paragraph	DCD R9

Revision 4 *(continued)*

Section	Changes	Reason for Change
Bases 3.8.3 Actions A.1, A.2 and A.3, 3.8.3, Actions B.1, B.2, C.1 and C.2, 3.8.3, Action G.1, SR 3.8.3.2 and SR 3.8.3.5	Changed bracketed minimum battery cell voltage from “2.11 V” to 2.09 V”	Revised as suggested
Bases 3.8.3 Actions B.1, B.2, C.1, C.2, and G.1	Added LMA COL Item 16.0-1-A	DCD R9
Bases 3.8.3 Actions B.1, B.2, C.1, C.2, and G.1, SR 3.8.3.1	Incorporated bracketed information for determining if battery is partially discharged (i.e., float current > 30 amps)	DCD revised method for determining if battery is partially discharged; values based on battery manufacturer’s recommendations.
Bases SR 3.8.3.1	Incorporated bracketed information regarding percent battery charge (i.e., 95%) and assumed design margin (5%)	DCD revised method and bases for determining if battery is fully charged; values based on battery manufacturer’s recommendations.
Bases SR 3.8.3.2 and SR 3.8.3.5	Incorporated bracketed float voltage range that requires action by Specification 5.5.10 from “2.15 Vpc at 25°C (77°F) but greater than 2.11 Vpc” to 2.13 Vpc at 25°C (77°F) but greater than 2.09 Vpc”	Based on battery manufacturer’s recommendations
Bases SR 3.8.3.4	Incorporated minimum battery electrolyte temperature bracketed information (i.e., 16°C (60°F))	DCD revised requirements for determining if battery can provide required current and voltage; value based on battery manufacturer’s recommendations.

Revision 1

Section	Changes
All	Updated to align with DCD R5
Introduction	Added LMAs and delimiters
Technical Specifications and Bases IBR and COL Information Item completion table	Deleted

TECHNICAL SPECIFICATIONS AND BASES

Introduction

NAPS COL 16.0-1-A

The ESBWR Generic Technical Specifications (GTS) and Bases of the referenced certified design are incorporated by reference into these plant-specific Technical Specifications (TS) with the following departures and/or supplements.

The GTS and Bases include brackets that are designated as COL-Applicant items. These bracketed items have left-margin annotation labels that correspond to items in GTS Table 16.0-1-A, "COL-Applicant Open Items."

The following information is provided to complete the COL-Applicant items.

STD COL 16.0-1-A 3.1.3-1 3.1.3-2 3.1.4-1

1. Flexibility for Slow Control Rod Scram Times

GTS and Bases:

GTS and Bases include provisions for optional "slow" scram time allowances based upon analysis as outlined in the LCO Bases for Specification 3.1.4.

Plant-Specific TS:

Remove the bracketed provisions for "slow" scram times in GTS and Bases 3.1.3 and 3.1.4.

Justification:

GTS provide an optional flexibility that is not supported at this time. The plant-specific TS require all scram times to meet the analytical time, which assures conservative reactivity insertion rates.

STD COL 16.0-1-A 3.1.7-1

2. Concentration of Sodium Pentaborate

GTS and Bases:

GTS and Bases 3.1.7 include a bracketed action (Action A) that allows up to 72 hours to restore the concentration of sodium pentaborate in solution in one or more accumulators to within limits.

Plant-Specific TS:

Remove the bracketed information in GTS and Bases 3.1.7, Action A.

Justification:

GTS provide an optional flexibility that is not supported at this time (i.e., removal of Action A is more restrictive).

NAPS COL 16.0-1-A
3.3.7.1-2
3.3.7.2-1
3.7.2-1
5.5.12-1

3. Hazardous Chemicals

GTS and Bases:

GTS and Bases 3.7.2 Action B.2, Bases 3.3.7.1 and 3.3.7.2 (Background sections), and GTS 5.5.12 include bracketed information on hazardous chemicals.

Plant-Specific TS:

Remove the bracketed information pertaining to hazardous chemicals.

Justification:

Hazardous chemical protection for the CRHAVS is not required based on the site-specific evaluation presented in FSAR Section 6.4.5.

STD COL 16.0-1-A
1.1-1
3.4.4-1
3.4.4-2
3.4.4-3
5.6.4-1

4. Pressure and Temperature Limits Report (PTLR)

GTS and Bases:

GTS 1.1, GTS and Bases 3.4.4, and GTS 5.6.4 include bracketed references to the PTLR.

Plant-Specific TS:

Retain PTLR. In TS 5.6.4, under item b, insert the title of the GEH PTLR methodology document.

Justification:

NEDC 33441P, “GE Hitachi Nuclear Energy Methodology for the Development of ESBWR Reactor Pressure Vessel Pressure-Temperature Curves,” (ML13346A654) provides an acceptable approach for developing a North Anna 3 Reactor Pressure Vessel pressure-temperature curve and providing initial and periodic reports to the NRC.

STD COL 16.0-1-A 3.7.4-1 5.6.3-1

5. Minimum Critical Power Ratio - Main Turbine Bypass System

GTS and Bases:

GTS and Bases 3.7.4 and GTS 5.6.3 include bracketed information on LCO 3.2.2, Minimal Critical Power Ratio (MCPR), that may be applied to allow continued operation with the Main Turbine Bypass System inoperable.

Plant-Specific TS:

Remove the bracketed information in TS 3.7.4, LCO 3.7.4. Remove the bracketed information in Bases 3.7.4, Applicable Safety Analysis, LCO, and Actions. Remove the bracketed information in TS 5.6.3.

Justification:

The GTS provide an optional flexibility that is not supported at this time.

STD COL 16.0-1-A 3.7.4-2

6. Main Turbine Bypass Valve

GTS and Bases:

GTS and Bases 3.7.4, SR 3.7.4.1, include a bracketed frequency for the surveillance to verify one complete cycle of each main turbine bypass valve.

Plant-Specific TS:

Remove the brackets from the frequency of SR 3.7.4.1 and use the stated frequency of 31 days.

Justification:

The Reviewer’s Note states that a frequency of 31 days will be used unless an evaluation is performed and approved by the NRC. This GTS optional flexibility is not supported at this time.

STD COL 16.0-1-A 3.7.6-1

7. Minimum Critical Power Ratio - SCRRI/SRI

GTS and Bases:

GTS and Bases 3.7.6 include bracketed information on the application of LCO 3.2.2, Minimum Critical Power Ratio (MCPR), in order to continue operation when the SCRRI or SRI Functions are inoperable.

Plant-Specific TS:

Remove the bracketed information in TS and Bases 3.7.6.

Justification:

The GTS provide an optional flexibility that is not supported at this time.

NAPS COL 16.0-1-A 4.1-1

8. Plant Location

GTS:

GTS 4.1 includes a bracketed requirement for the COL applicant to provide the plant-specific description of the plant location.

Plant-Specific TS:

The plant-specific TS 4.1 includes the description of the site in place of the bracketed information.

Justification:

The site description provided is consistent with the FSAR description of the site location.

STD COL 16.0-1-A 5.2.2-1

9. Non-licensed Operators for Two Units

GTS:

The Reviewer's Note associated with GTS 5.2.2 specifies the number of non-licensed operators required for two units when both units are shut down.

Plant-Specific TS:

Retain the standard wording applicable to single-unit manning requirements.

Justification:

The ESBWR is a single unit facility.

STD COL 16.0-1-A 5.3.1-1

10. Minimum Qualification Standards for Unit Staff

GTS:

GTS 5.3.1 includes bracketed information on the specification of minimum qualifications for members of the unit staff.

Plant-Specific TS:

Remove the bracketed information on TS 5.3.1. Add exception for cold license operator training.

Justification:

Unit staff qualification standards provided are consistent with the FSAR, including FSAR Section 13.2, for the stated exception.

STD COL 16.0-1-A 5.4.1-1 5.4.1-2

11. Guidance Documents for Procedures

GTS:

GTS 5.4 includes bracketed guidance documents for written procedures.

Plant-Specific TS:

Remove the brackets from the guidance documents.

Justification:

Written procedures are established, implemented, and maintained covering activities defined in the bracketed guidance documents.

STD COL 16.0-1-A 5.5.6-1

12. Temporary Outdoor Liquid Storage Tanks

GTS:

GTS 5.5.6 includes bracketed information for applicants incorporating unprotected outdoor liquid radioactive storage tanks in their design.

Plant-Specific TS:

Remove the bracketed information in TS 5.5.6.

Justification:

The plant-specific design does not include temporary outdoor liquid radioactive waste storage tanks.

STD COL 16.0-1-A 5.5.9-1

13. Exemptions for Regulatory Guide 1.163

GTS:

GTS 5.5.9 includes bracketed information for applicants requiring additional exemptions to Regulatory Guide (RG) 1.163.

Plant-Specific TS:

Remove bracketed information in TS 5.5.9.

Justification:

No further exemptions to RG 1.163 are requested in the COLA.

NAPS COL 16.0-1-A 5.6.1-1 5.6.2-1

14. Multi-Unit Site Reporting Options

GTS:

GTS 5.6.1 and 5.6.2 include bracketed information in Notes for applicants with a multi-unit site.

Plant-Specific TS:

Remove the brackets from the Notes in TS 5.6.1 and 5.6.2.

Justification:

The multi-unit site options and standard reporting format apply to the plant-specific site.

STD COL 16.0-1-A 5.6.1-2

15. Annual Radiological Environmental Operating Report Format

GTS:

GTS 5.6.1 includes bracketed allowance to specify the format of the Annual Radiological Environmental Operating Report.

Plant-Specific TS:

Remove the brackets and retain the standard option in TS 5.6.1.

Justification:

The standard format applies to the plant-specific site.

STD COL 16.0-1-A 5.6.3-2

16. Additional Core Operating Limits for COLR

GTS:

GTS 5.6.3 includes bracketed option to list additional specifications that may reference the COLR.

Plant-Specific TS:

Remove the bracketed option in TS 5.6.3.

Justification:

There are no additional Specifications addressing COLR.

**STD COL 16.0-1-A
3.3.1.1-2
3.3.1.2-1
3.3.1.4-2
3.3.1.5-2
3.3.5.1-2
3.3.5.2-1
3.3.5.3-2
3.3.5.4-1
3.3.6.1-2
3.3.6.2-1
3.3.6.3-2
3.3.6.4-1
3.3.7.1-3
3.3.7.2-2**

17. Response Time Testing

GTS Bases:

GTS Bases for Instrumentation Specifications include an allowance to exclude certain sensors or other instrumentation and actuation components from response time testing.

Plant-Specific TS:

Remove the bracketed provision for the response time testing relaxation.

Justification:

The GTS provides an optional flexibility that is not supported at this time.

**STD COL 16.0-1-A
3.1.5-1
3.9.5-1**

18. Minimum and Nominal Control Rod Scram Accumulator Pressure

GTS:

GTS and Bases for SR 3.1.5.1 and SR 3.9.5.2, and GTS Bases for TS 3.9.5 LCO include bracketed control rod scram accumulator pressures for the minimum pressure to support assumed scram times. Also, GTS Bases for SR 3.1.5.1 provides bracketed expected pressure.

Plant-Specific TS:

Complete the bracketed item for minimum scram accumulator pressure and remove the bracketed detail reflecting the expected pressure.

Include supplemental information reflecting the basis for the minimum scram accumulator pressure.

Justification:

As detailed in the Bases for SR 3.1.5.1, the minimum accumulator pressure reflects a bounding value based on the ABWR CRD HCU accumulator minimum pressure value.

Removal of the expected pressure detail does not eliminate any information required to support the applicable requirement (i.e., the HCU minimum pressure for control rod scram capability). The unavailability of this detail reflects the preliminary design of the system, which has not progressed sufficiently to define the expected pressure. Inclusion of the expected pressure in the Bases does not serve the underlying purpose of identifying the minimum accumulator pressure, and is not necessary to achieve the underlying purpose of the Technical Specifications.

STD COL 16.0-1-A 3.8.1-1

19. Acceptance Criteria for Battery Charger Testing

GTS:

GTS and Bases for SR 3.8.1.2 includes bracketed specifics on the safety-related battery charger test duration.

Plant-Specific TS:

Complete the bracketed values.

Justification:

Values are bounding based on GUTOR manufacturer's recommendations for battery charger test duration.

STD COL 16.0-1-A 3.8.3-1

20. Acceptance Criteria for Verification of Fully Charged Battery

GTS:

GTS Bases for TS 3.8.3 Actions B, C and G, and GTS and Bases for SR 3.8.3.1 include bracketed method for determining the state-of-charge for the battery.

Plant-Specific TS:

Complete the brackets with float current.

Justification:

Values for battery float current acceptance criteria and battery capacity margin for state of charge are based on the battery manufacturer's recommendations.

STD COL 16.0-1-A 3.8.1-4 3.8.3-3 5.5.10-1

21. Battery Cell Parameters

GTS:

GTS Bases for SR 3.8.1.1 and TS 3.8.3 Background; the GTS and Bases for TS 3.8.3 Actions, SR 3.8.3.2, and SR 3.8.3.5; and GTS 5.5.10.a, include bracketed battery cell voltage values and bracketed basis for the values. GTS Bases for SR 3.8.1.1 includes a bracketed location for monitoring the applicable battery temperature for battery voltage compensation. GTS Bases for TS 3.8.3

Background includes bracketed values for nominal specific gravity and number of battery cells. GTS Bases for SR 3.8.3.4 includes bracketed value for battery pilot cell electrolyte minimum temperature.

Plant-Specific TS:

Complete the brackets.

Justification:

Various values for battery parameters are based on the battery manufacturer's recommendations. Total number of battery cells is supported in ESBWR DCD Tier 2 Table 8.3-4.

STD COL 16.0-1-A 3.8.1-5 3.8.3-4

22. Battery Margin for Aging Factor and State of Charge Uncertainty

GTS:

GTS Bases for TS 3.8.1 Background and GTS and Bases for SR 3.8.3.6, include bracketed battery end-of-life capacity limit.

Plant-Specific TS:

Complete the brackets.

Justification:

Values are based on the battery manufacturer's recommendations.

STD COL 16.0-1-A 5.5.11-1

23. Setpoint Control Program Methodology and Implementation

GTS:

GTS 5.5.11.b includes bracketed references to the approved GEH setpoint methodology revision and the corresponding NRC Safety Evaluation date, as well as applicable ADAMS accession numbers.

Plant-Specific TS:

The approved GEH setpoint methodology revision and the corresponding NRC Safety Evaluation date, as well as applicable ADAMS accession numbers are included.

Justification:

Reviewed and approved by the NRC in NEDE-33304P-A, “GEH ESBWR Setpoint Methodology,” Revision 4, dated May 2010, (Public Version ML101450251), and the conditions stated in the associated NRC safety evaluation, Letter to GEH from NRC, “Final Safety Evaluation Report for the Economic Simplified Boiling Water Reactor Design,” dated March 9, 2011, (ML110050215, specifically Chapter 7 FSER ML110030049 and Chapter 16 FSER ML110030064).

TECHNICAL SPECIFICATIONS

FOR NORTH ANNA UNIT 3

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1.0 USE AND APPLICATION

1.1 Definitions

NOTE

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an in place qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL FUNCTIONAL TEST	A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

1.1 Definitions

CONTROL ROOM HABITABILITY AREA (CRHA) HEATING, VENTILATION, AND AIR CONDITIONING (HVAC) SUBSYSTEM (CRHAVS) RESPONSE TIME	The CRHAVS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its CRHAVS initiation setpoint at the channel sensor until the CRHAVS equipment is capable of performing its safety function (i.e., the dampers travel to their required positions, fans start, etc.). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. The following exceptions are not considered to be CORE ALTERATIONS: a. Movement of startup range neutron monitors, local power range monitors, fixed in-core calibration detectors, or special movable detectors (including undervessel replacement); and b. Control rod movement, provided there are no fuel assemblies in the associated core cell. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific limits shall be determined for each reload cycle in accordance with Specification 5.6.3. Plant operation within these limits is addressed in individual Specifications.

1.1 Definitions

DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same Committed Effective Dose Equivalent as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The dose conversion factors used for this calculation shall be those listed in Federal Guidance Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," 1988.
EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME	The ECCS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS initiation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, etc.). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
ISOLATION CONDENSER SYSTEM (ICS) RESPONSE TIME	The ICS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ICS initiation setpoint at the channel sensor until the ICS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, etc.). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

1.1 Definitions

ISOLATION SYSTEM RESPONSE TIME	The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation initiation setpoint at the channel sensor until the isolation valves travel to their required positions. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

1.1 Definitions

LEAKAGE	LEAKAGE shall be: a. Identified LEAKAGE 1. LEAKAGE into the drywell such as that from pump seals or valve packing that is captured and conducted to a sump or collecting tank; or 2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; b. Unidentified LEAKAGE All LEAKAGE into the drywell that is not identified LEAKAGE; c. Total LEAKAGE Sum of the identified and unidentified LEAKAGE; and d. Pressure Boundary LEAKAGE LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.
LINEAR HEAT GENERATION RATE (LHGR)	The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components required for OPERABILITY of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.

1.1 Definitions

MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest Critical Power Ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, train, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.4.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 4500 MWt.

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1.1 Definitions

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 20°C (68°F); and c. All control rods are fully inserted except for the control rod or control rod pair of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.1 Definitions

TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. The response time may be measured by means of any series of sequential, overlapping, or total steps such that the entire response time is measured.

1.1 Definitions

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTOR MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE °C(°F)
1	Power Operation	Run	NA
2	Startup	Refuel[a] or Startup	NA
3	Hot Shutdown[a]	Shutdown	> 215.6 (420)
4	Stable Shutdown[a]	Shutdown	≤ 215.6 (420) and > 93.3 (200)
5	Cold Shutdown[a]	Shutdown	≤ 93.3 (200)
6	Refueling[b]	Shutdown or Refuel	NA

(a) All reactor vessel head closure bolts fully tensioned.

(b) One or more reactor vessel head closure bolts less than fully tensioned.

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1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances and Frequencies. The only logical connectors that appear in TS are <u>AND</u> and <u>OR</u>. The physical arrangement of these connectors constitutes logical conventions with specific meanings.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentions of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance or Frequency.

1.2 Logical Connectors

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify ... AND A.2 Restore ...	

In this example, the logical connector AND is used to indicate that, when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip ... OR A.2.1 Verify ... AND A.2.2.1 Reduce ... OR A.2.2.2 Perform ... OR A.3 Align ...	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

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1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).
DESCRIPTION	The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability. If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition. Once a Condition has been entered, subsequent trains, divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

1.3 Completion Times

DESCRIPTION (continued)

However, when a subsequent train, division, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, division, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery…"

1.3 Completion Times

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to be in MODE 3 within 12 hours AND in MODE 5 within 36 hours. A total of 12 hours is allowed for reaching MODE 3 and a total of 36 hours (not 48 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 6 hours, the time allowed for reaching MODE 5 is the next 30 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One valve inoperable.	A.1 Restore valve to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

When a valve is declared inoperable, Condition A is entered. If the valve is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable valve is restored to OPERABLE status after Condition B is entered, Conditions A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second valve is declared inoperable while the first valve is still inoperable, Condition A is not re-entered for the second valve. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable valve. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable valves is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

While in LCO 3.0.3, if one of the inoperable valves is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

1.3 Completion Times

EXAMPLES (continued)

On restoring one of the valves to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. This Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second valve being inoperable for > 7 days.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

1.3 Completion Times

EXAMPLES (continued)

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

<u>EXAMPLE 1.3-4</u>

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

1.3 Completion Times

EXAMPLES (continued)

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (plus the extension) expires while one or more valves are still inoperable, Condition B is entered.

EXAMPLE 1.3-5

ACTIONS

----------------------------NOTE----------------------------
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valves to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If

1.3 Completion Times

EXAMPLES (continued)

subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of

1.3 Completion Times

EXAMPLES (continued)

Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

<u>EXAMPLE 1.3-7</u>

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated. <u>AND</u> A.2 Restore subsystem to OPERABLE status.	1 hour <u>AND</u> Once per 8 hours thereafter 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

1.3 Completion Times

EXAMPLES (continued)	If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.
IMMEDIATE COMPLETION TIME	When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

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1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0.2, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria.

1.4 Frequency

DESCRIPTION (continued)

Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discuss these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, 3, and 4.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an

1.4 Frequency

EXAMPLES (continued)

extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The Surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the MODE or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

<u>EXAMPLE 1.4-2</u>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter

1.4 Frequency

EXAMPLES (continued)

Example 1.4-2 has two Frequencies. The first is a one-time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------ Not required to be performed until 12 hours after ≥ 25% RTP. ---	
Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day interval (plus the extension allowed by SR 3.0.2), but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the

1.4 Frequency

EXAMPLES (continued)

LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------- Only required to be met in MODE 1. -- Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------- Only required to be performed in MODE 1. ---	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, 3, or 4 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day interval (plus the extension allowed by SR 3.0.2), but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------- Not required to be met in MODES 3 and 4. --	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 or 4 (the assumed Applicability of the associated LCO is MODES 1, 2, 3, and 4). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODES 3 and 4, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODES 3 or 4, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

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2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 5.412 MPaG (785 psig):

THERMAL POWER shall be ≤ 25% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 5.412 MPaG (785 psig):

Greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition.

All MCPRs shall be greater than or equal to 1.18 during steady-state operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor vessel bottom pressure shall be ≤ 9.481 MPaG (1375 psig).

2.2 SL VIOLATIONS

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

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3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 2 within 7 hours;

b. MODE 3 within 13 hours;

c. MODE 4 within 25 hours; and

d. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO APPLICABILITY

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time;

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications; or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

LCO 3.0.5 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

LCO 3.0.6 When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.8, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO APPLICABILITY

LCO 3.0.6 (continued)	When a support system's Required Action directs a supported system to be declared inoperable or directs entry in Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.
LCO 3.0.7	Special Operations LCOs in Section 3.10 allow specified Technical Specifications (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Special Operations LCOs is optional. When a Special Operations LCO is desired to be met but is not met, the ACTIONS of the Special Operations LCO shall be met. When a Special Operations LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1	SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.
SR 3.0.2	The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met. For Frequencies specified as "once," the above interval extension does not apply. If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance. Exceptions to this Specification are stated in the individual Specifications.
SR 3.0.3	If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed. If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Conditions must be entered.

SR APPLICABILITY

SR 3.0.4	Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their Specified Frequency, except as provided by SR 3.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4. This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be:

a. ≥ 0.38% Δk/k, with the highest worth control rod or rod pair analytically determined; or

b. ≥ 0.28% Δk/k, with the highest worth control rod or rod pair determined by test.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limits in MODE 1 or 2.	A.1 Restore SDM to within limits.	6 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	12 hours
C. SDM not within limits in MODE 3 or 4.	C.1 Initiate action to fully insert all insertable control rods.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. SDM not within limits in MODE 5.	D.1 Initiate action to fully insert all insertable control rods.	Immediately
	AND	
	D.2.1 Initiate action to isolate reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas.	Immediately
	OR	
	D.2.2 Initiate action to establish reactor building REPAVS and CONAVS area automatic isolation capability on respective exhaust high radiation signals.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. SDM not within limits in MODE 6.	E.1	Suspend CORE ALTERATIONS except for control rod insertion and fuel assembly removal.	Immediately
	<u>AND</u>		
	E.2	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
	<u>AND</u>		
	E.3.1	Initiate action to isolate reactor building REPAVS and CONAVS areas.	Immediately
	<u>OR</u>		
	E.3.2	Initiate action to establish reactor building REPAVS and CONAVS area automatic isolation capability on respective exhaust high radiation signals.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within limits.	Prior to each in vessel fuel movement during fuel loading sequence <u>AND</u> Once within 4 hours after criticality following fuel movement within the reactor pressure vessel or control rod replacement

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Reactivity Anomalies

LCO 3.1.2 The reactivity difference between the monitored core k_{eff} and the predicted core k_{eff} shall be within ± 1% Δk/k.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Core reactivity difference not within limit.	A.1 Restore core reactivity difference to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	Verify core reactivity difference between the monitored core k_{eff} and the predicted core k_{eff} is within ± 1% Δk/k.	Once within 24 hours after reaching equilibrium conditions following startup after fuel movement within the reactor pressure vessel or control rod replacement <u>AND</u> 1000 MWD/T thereafter during operations in MODE 1

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Control Rod OPERABILITY

LCO 3.1.3 Each control rod shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each control rod.

2. Enter applicable Conditions and Required Actions of LCO 3.7.6, "Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions," when inoperable control rods result in inoperability of the SRI function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One withdrawn control rod stuck.	----------NOTE---------- A stuck control rod may be bypassed in the Rod Control & Information System (RC&IS) in accordance with SR 3.3.2.1.9, if required to allow continued operation. ------------------------------	
STD COL 16.0-1-A 3.1.3-1	A.1 Disarm the associated control rod drive (CRD).	2 hours
	<u>AND</u>	
STD COL 16.0-1-A 3.1.3-1	A.2 Perform SR 3.1.3.2 and SR 3.1.3.3 for each withdrawn OPERABLE control rod.	24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP)
	<u>AND</u>	
	A.3 Perform SR 3.1.1.1.	72 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two or more withdrawn control rods stuck.	B.1 Be in MODE 3.	12 hours
C. One or more control rods inoperable for reasons other than Condition A or B.	C.1 --------NOTE--------- Inoperable control rods may be bypassed in the RC&IS in accordance with SR 3.3.2.1.9, if required, to allow insertion of inoperable control rod and continued operation. ---------------------	
	Fully insert inoperable control rod.	3 hours
	AND	
	C.2 Disarm the associated CRD.	4 hours
D. --------NOTE--------- Not applicable when THERMAL POWER > 10% RTP. ---------------------	D.1 Restore compliance with Ganged Withdrawal Sequence Restrictions (GWSR).	4 hours
	OR	
Two or more inoperable control rods not within separation limits.	D.2 Restore control rod to OPERABLE status.	4 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition A, C, or D not met. OR Nine or more control rods inoperable.	E.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Determine the position of each control rod.	24 hours
SR 3.1.3.2	----------NOTE---------- Not required to be performed until 7 days after the control rod is withdrawn and THERMAL POWER is greater than the LPSP. ------------------------------ Insert each fully withdrawn control rod two notches.	7 days
SR 3.1.3.3	----------NOTE---------- Not required to be performed until 31 days after the control rod is withdrawn and THERMAL POWER is greater than the LPSP. ------------------------------ Insert each partially withdrawn control rod two notches.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.4	Perform applicable SRs of LCO 3.1.4.	In accordance with SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4
SR 3.1.3.5	Verify each control rod does not go to the withdrawn overtravel position.	Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect coupling

STD COL 16.0-1-A
3.1.3-2

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Control Rod Scram Times

LCO 3.1.4 Each control rod scram time shall be within limits of Table 3.1.4-1.

STD COL 16.0-1-A 3.1.4-1

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control rod scram time not within limits of Table 3.1.4-1. (STD COL 16.0-1-A 3.1.4-1)	A.1 Declare affected control rod inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
During single or control rod pair scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 6.55 MPaG (950 psig).	Prior to exceeding 40% RTP after each reactor shutdown ≥ 120 days
SR 3.1.4.2	Verify, for a representative sample, each tested control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 6.55 MPaG (950 psig).	200 days cumulative operation in MODE 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.3	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with any reactor steam dome pressure.	Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect scram time
SR 3.1.4.4	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 6.55 MPaG (950 psig).	Prior to exceeding 40% RTP after fuel movement within the affected core cell <u>AND</u> Prior to exceeding 40% RTP after work on control rod or CRD System which could affect scram time

STD COL 16.0-1-A
3.1.4-1

Table 3.1.4-1 (page 1 of 1)
Control Rod Scram Times

CONTROL ROD PERCENT INSERTION	SCRAM TIME LIMITS[a][b] (seconds)	
	REACTOR VESSEL STEAM DOME PRESSURE[c] 7.340 MPaG (1065 psig)	REACTOR VESSEL STEAM DOME PRESSURE[c] 8.463 MPaG (1227 psig)
10	0.34	0.37
40	0.80	0.96
60	1.15	1.36
100	2.23	2.95

(a) Maximum scram time from fully withdrawn position, based on de-energization of scram pilot valve solenoids as time zero.

(b) Scram times as a function of reactor steam dome pressure, when < 7.340 MPaG (1065 psig), are within established limits.

(c) For intermediate reactor steam dome pressures, the scram time criteria are determined by linear interpolation.

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3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Control Rod Scram Accumulators

LCO 3.1.5 Each control rod scram accumulator shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

- - - - - - - - - - - - - - - - - - NOTE - - - - - - - - - - - - - - - - - -
Separate Condition entry is allowed for each control rod scram accumulator.
- -

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One control rod scram accumulator inoperable.	A.1 Declare the associated control rod(s) inoperable.	8 hours
B. Two or more control rod scram accumulators inoperable.	B.1 Declare the associated control rods inoperable.	1 hour
C. Required Action and associated Completion Time not met.	C.1 --------NOTE--------- Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. --------------------- Place the reactor mode switch in the shutdown position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1 STD COL 16.0-1-A 3.1.5-1	Verify each control rod scram accumulator pressure is ≥ 12.75 MPaG (1849 psig).	7 days

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Rod Pattern Control

LCO 3.1.6 The position of OPERABLE control rods shall comply with the requirements of the Ganged Withdrawal Sequence Restrictions (GWSR).

APPLICABILITY: MODES 1 and 2 with THERMAL POWER ≤ 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more OPERABLE control rod positions not in compliance with GWSR.	------NOTE------ Affected control rods may be bypassed in the Rod Control & Information System (RC&IS) in accordance with SR 3.3.2.1.9. -----------------	
	A.1 Move associated control rod(s) to correct position.	8 hours
	<u>OR</u>	
	A.2 Declare associated control rod(s) inoperable.	8 hours
B. Nine or more OPERABLE control rod positions not in compliance with GWSR.	------NOTE------ Affected control rods may be bypassed in RC&IS in accordance with SR 3.3.2.1.9 for insertion only. -----------------	
	B.1 Suspend withdrawal of control rods.	Immediately
	<u>AND</u>	
	B.2 Place the reactor mode switch in the shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify position of all OPERABLE control rods comply with GWSR.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 The SLC System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One injection squib valve flow path inoperable in one or more trains. [STD COL 16.0-1-A 3.1.7-1]	A.1 Restore injection squib valve flow path(s) to OPERABLE status.	7 days
B. One accumulator isolation valve inoperable for closing in one or more trains.	B.1 Restore accumulator isolation valve(s) to OPERABLE status.	7 days
C. SLC system inoperable for reasons other than Condition A or B. OR Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.7.1 Verify available volume of sodium pentaborate solution in each accumulator is ≥ 7.8 m^3 (2061 gallons) and ≤ 9.7 m^3 (2562 gallons).	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.2	Verify temperature of the areas containing accumulator, piping, and valves containing sodium pentaborate solution is within limits of Figure 3.1.7-1.	24 hours
SR 3.1.7.3	Verify SLC accumulator pressure is ≥ 14.72 MPaG (2135 psig).	24 hours
SR 3.1.7.4	---------- NOTE --------- Not required to be met for one initiator intermittently disabled under administrative controls. --------------------- Verify continuity of one safety-related initiator associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for each injection squib valve.	31 days
SR 3.1.7.5	---------- NOTE --------- SLC flow paths may be isolated intermittently under administrative controls. --------------------- Verify each SLC System manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days

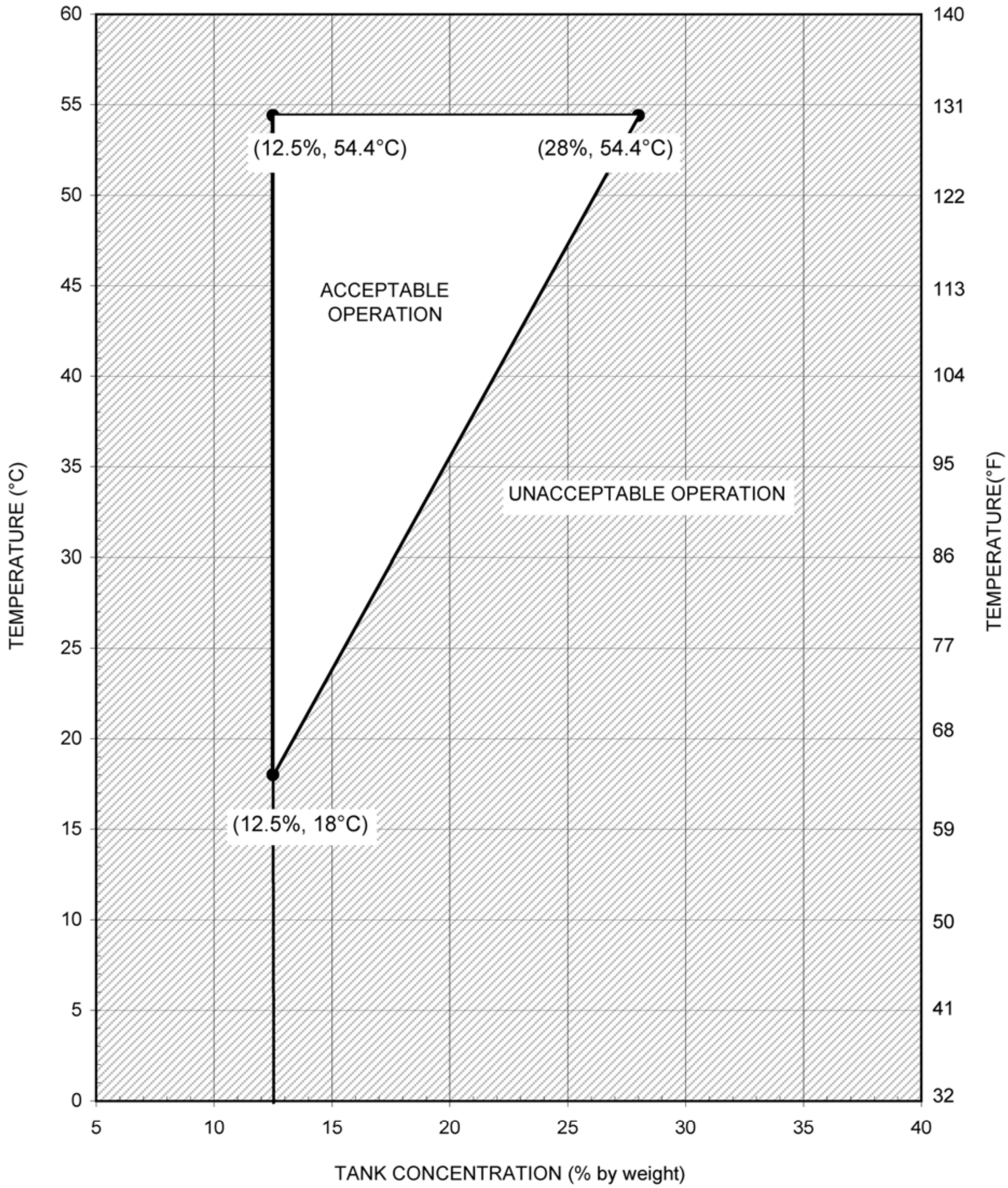
SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.6	Verify the concentration of sodium pentaborate in solution is within the limits of Figure 3.1.7-1.	31 days AND Once within 24 hours after water or sodium pentaborate is added to solution AND Once within 24 hours after solution temperature is restored within limit
SR 3.1.7.7	------------NOTE------------ Valve actuation may be excluded. ---------------------------- Verify SLC System actuates on an actual or simulated initiation signal.	24 months
SR 3.1.7.8	Perform CHANNEL CALIBRATION of accumulator level instrumentation channels consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.1.7.9	------------NOTE------------ Valve actuation may be excluded. ---------------------------- Verify flow through one flow path on one SLC train from accumulator into reactor pressure vessel.	24 months on a STAGGERED TEST BASIS for each flow path

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.10	Verify sodium pentaborate enrichment is ≥ 94.0 atom percent B-10.	Prior to addition to SLC accumulator

Figure 3.1.7-1
Sodium Pentaborate Solution Temperature/Concentration Requirements



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3.2 POWER DISTRIBUTION LIMITS

3.2.1 LINEAR HEAT GENERATION RATE (LHGR)

LCO 3.2.1 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter

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3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.2.1 Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter

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3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 Three RPS instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

NOTE

Separate Condition entry is allowed for each RPS instrumentation channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Verify associated instrument channel in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with RPS trip capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.1.1-1 for the associated Function.	Immediately
C. As required by Required Action B.1 and referenced in Table 3.3.1.1-1.	C.1 Reduce THERMAL POWER to < 40% RTP.	4 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action B.1 and referenced in Table 3.3.1.1-1.	D.1 Reduce THERMAL POWER to < 25% RTP.	4 hours
E. As required by Required Action B.1 and referenced in Table 3.3.1.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action B.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 3.	12 hours
G. As required by Required Action B.1 and referenced in Table 3.3.1.1-1.	G.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

NOTE

Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.1.1.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.3.1.1.4	Verify RPS RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.1.1-1 (page 1 of 2)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1. Neutron Monitor System Input - Startup Range Neutron Monitors	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2
	6[(a)]	G	SR 3.3.1.1.1 SR 3.3.1.1.2
2. Neutron Monitor System Input - Average Power Range Monitors/ Oscillation Power Range Monitors	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2
3. Scram Accumulator Charging Water Header Pressure - Low-Low	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3
	6[(a)]	G	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3
4. Reactor Vessel Steam Dome Pressure - High	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
5. Reactor Vessel Water Level - Low, Level 3	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
6. Reactor Vessel Water Level - High, Level 8	≥ 25% RTP	D	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
7. Main Steam Isolation Valve - Closure (Per Steam Line)	1	E	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
8. Drywell Pressure - High	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

Table 3.3.1.1-1 (page 2 of 2)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
9. Suppression Pool Temperature - High	1,2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
10. Turbine Stop Valve Closure Trip	≥ 40% RTP	C	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
11. Turbine Control Valve Fast Closure Trip Oil Pressure - Low	≥ 40% RTP	C	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
12. Main Condenser Pressure - High	1	E	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
13. Power Generation Bus Loss	1	E	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.4
14. Feedwater Temperature Biased Simulated Thermal Power – High	≥ 25% RTP	D	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3
15. Simulated Thermal Power Biased Feedwater Temperature - High	≥ 25% RTP	D	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3
16. Simulated Thermal Power Biased Feedwater Temperature - Low	≥ 25% RTP	D	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3

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3.3 INSTRUMENTATION

3.3.1.2 Reactor Protection System (RPS) Actuation

LCO 3.3.1.2 Three Reactor Protection System (RPS) automatic actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

------------------------------------ NOTE ------------------------------------
Separate Condition entry is allowed for each RPS automatic actuation division.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RPS automatic actuation division inoperable.	A.1 Verify required division in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met in MODE 1 or 2. <u>OR</u> RPS automatic actuation capability not maintained in MODE 1 or 2.	B.1 Be in MODE 3.	12 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met in MODE 6. OR RPS automatic actuation capability not maintained in MODE 6.	C.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.1.2.2	Verify RPS RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS

3.3 INSTRUMENTATION

3.3.1.3 Reactor Protection System (RPS) Manual Actuation

LCO 3.3.1.3 The RPS manual actuation channels for each Function in Table 3.3.1.3-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.3-1.

ACTIONS

------------------------------------ NOTE ------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One manual actuation channel inoperable in one Function.	A.1 Verify affected channel in trip.	12 hours
B. One manual actuation channel inoperable in both Functions.	B.1 Verify affected channels in trip.	Immediately
C. Both manual actuation channels inoperable in one or both Functions in MODE 1 or 2. <u>OR</u> Required Action and associated Completion Time of Condition A or B not met in MODE 1 or 2.	C.1 Be in MODE 3.	12 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Both manual actuation channels inoperable in one or both Functions in MODE 6. OR Required Action and associated Completion Time of Condition A or B not met in MODE 6.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.3.1	Perform CHANNEL FUNCTIONAL TEST for each RPS Manual Scram Function channel.	7 days
SR 3.3.1.3.2	Perform CHANNEL FUNCTIONAL TEST for Reactor Mode Switch - Shutdown Position Function.	24 months

Table 3.3.1.3-1 (page 1 of 1)
Reactor Protection System Manual Actuation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS
1. Manual Scram	1,2,6[(a)]	2
2. Reactor Mode Switch - Shutdown Position	1,2,6[(a)]	2

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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3.3 INSTRUMENTATION

3.3.1.4 Neutron Monitoring System (NMS) Instrumentation

LCO 3.3.1.4 The NMS instrumentation channels of the three NMS instrumentation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.1.4-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.4-1.

ACTIONS

NOTE

Separate Condition entry is allowed for each NMS instrument channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with instrumentation channel(s) inoperable in one required division.	A.1 Verify associated instrument channel in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with NMS trip capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.1.4-1 for the associated Function.	Immediately
C. As required by Required Action B.1 and referenced in Table 3.3.1.4-1.	C.1 Be in MODE 2.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action B.1 and referenced in Table 3.3.1.4-1.	D.1 Be in MODE 3.	12 hours
E. As required by Required Action B.1 and referenced in Table 3.3.1.4-1.	E.1 Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	<u>AND</u>	
	E.2 Restore required channels to OPERABLE status.	120 days
F. Required Action and associated Completion Time of Condition E not met.	F.1 Reduce THERMAL POWER to < 25% RTP.	4 hours
G. As required by Required Action B.1 and referenced in Table 3.3.1.4-1.	G.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

--- NOTE ---
Refer to Table 3.3.1.4-1 to determine which SRs apply for each NMS Instrumentation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.4.1	Perform CHANNEL CHECK on each required channel.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.4.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ------------------------------ Verify absolute difference between the average power range monitor (APRM) channels and calculated power ≤ 2% RTP while operating at ≥ 25% RTP for each required channel.	7 days
SR 3.3.1.4.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ------------------------------ Perform CHANNEL FUNCTIONAL TEST on each required channel.	7 days
SR 3.3.1.4.4	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.1.4.5	Calibrate local power range monitors on each required channel.	750 MWD/T average core exposure
SR 3.3.1.4.6	----------NOTES---------- 1. For Functions 1.a, 1.b and 2.a not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 2. Neutron detectors may be excluded. ------------------------------ Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.4.7	Verify APRM Simulated Thermal Power – High time constant is within limit for each required channel.	24 months
SR 3.3.1.4.8	------------------NOTE------------------ Neutron detectors are excluded. -- Verify RPS RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.1.4.9	Verify Oscillation Power Range Monitor (OPRM) is not bypassed when THERMAL POWER is ≥ 25% RTP.	24 months

Table 3.3.1.4-1 (page 1 of 2)
Neutron Monitoring System (NMS) Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER REQUIRED DIVISION	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1.	Startup Range Neutron Monitors (SRNM)				
	a. Neutron Flux - Short Period	2	2	D	SR 3.3.1.4.1 SR 3.3.1.4.3 SR 3.3.1.4.6 SR 3.3.1.4.8
		6[(a)]	2	G	SR 3.3.1.4.1 SR 3.3.1.4.3 SR 3.3.1.4.6 SR 3.3.1.4.8
	b. Inop	2	2	D	SR 3.3.1.4.3
		6[(a)]	2	G	SR 3.3.1.4.3
2.	Average Power Range Monitors				
	a. Fixed Neutron Flux - High, Setdown	2	1	D	SR 3.3.1.4.1 SR 3.3.1.4.3 SR 3.3.1.4.5 SR 3.3.1.4.6 SR 3.3.1.4.8
	b. APRM Simulated Thermal Power - High	1	1	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6 SR 3.3.1.4.7 SR 3.3.1.4.8
	c. Fixed Neutron Flux - High	1	1	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6 SR 3.3.1.4.8
	d. Inop	1,2	1	D	SR 3.3.1.4.4

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

Table 3.3.1.4-1 (page 2 of 2)
Neutron Monitoring System (NMS) Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER REQUIRED DIVISION	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
3. Oscillation Power Range Monitor - Upscale	≥ 25% RTP	1	E	SR 3.3.1.4.4 SR 3.3.1.4.6 SR 3.3.1.4.8 SR 3.3.1.4.9

3.3 INSTRUMENTATION

3.3.1.5 Neutron Monitoring System (NMS) Automatic Actuation

LCO 3.3.1.5 Three NMS automatic actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for the Functions in Table 3.3.1.5-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.5-1.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each NMS automatic actuation division.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required division inoperable.	A.1 Verify required division in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with NMS actuation capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.1.5-1 for the associated actuation Function.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action B.1 and referenced in Table 3.3.1.5-1.	C.1 Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	AND	
	C.2 Restore required channels to OPERABLE status.	120 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Reduce THERMAL POWER to < 25% RTP.	4 hours
E. As required by Required Action B.1 and referenced in Table 3.3.1.5-1.	E.1 Be in MODE 3.	12 hours
F. As required by Required Action B.1 and referenced in Table 3.3.1.5-1.	F.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.5.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.1.5.2	Verify RPS RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.1.5-1 (page 1 of 1)
Neutron Monitoring System (NMS) Instrumentation

FUNCTION		APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1
1.	Startup Range Neutron Monitors	2	E
		6[a]	F
2.	Average Power Range Monitors	1,2	E
3.	Oscillation Power Monitors	$\geq$ 25% RTP	C

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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3.3 INSTRUMENTATION

3.3.1.6 Startup Range Neutron Monitor (SRNM) Instrumentation

LCO 3.3.1.6 The SRNM instrumentation in Table 3.3.1.6-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.6-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRNMs inoperable in MODE 3, 4, or 5.	A.1 Fully insert all insertable control rods.	1 hour
	<u>AND</u>	
	A.2 Place reactor mode switch in the shutdown position.	1 hour
B. One or more required SRNMs inoperable in MODE 6.	B.1 Suspend CORE ALTERATIONS except for control rod insertion.	Immediately
	<u>AND</u>	
	B.2 Initiate action to insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

- - - - - - - - - - - - - - - - - - - NOTE - - - - - - - - - - - - - - - - - - -

Refer to Table 3.3.1.6-1 to determine which SRs apply for each applicable MODE or other specified conditions.

- -

SURVEILLANCE		FREQUENCY
SR 3.3.1.6.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.1.6.2	- - - - - - - - - - NOTES - - - - - - - - - - 1. Only required to be met during CORE ALTERATIONS. 2. One SRNM may be used to satisfy more than one of the following. - Verify an OPERABLE SRNM detector is located in: a. The fueled region; b. The core quadrant where CORE ALTERATIONS are being performed when the associated SRNM is included in the fueled region; and c. A core quadrant adjacent to where CORE ALTERATIONS are being performed, when the associated SRNM is included in the fueled region.	12 hours
SR 3.3.1.6.3	Perform CHANNEL CHECK on each required channel.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.6.4	---------- NOTE ---------- Not required to be met with less than or equal to four fuel assemblies adjacent to the SRNM and no other fuel assemblies in the associated core quadrant. ------------------------------ Verify count rate is ≥ 3.0 cps.	12 hours during CORE ALTERATIONS <u>AND</u> 24 hours
SR 3.3.1.6.5	Perform CHANNEL FUNCTIONAL TEST on each required channel.	7 days
SR 3.3.1.6.6	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.1.6.7	---------- NOTE ---------- Neutron detectors may be excluded. ------------------------------ Perform CHANNEL CALIBRATION on each required channel.	24 months

Table 3.3.1.6-1 (page 1 of 1)
Startup Range Neutron Monitor Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS
1. Startup Range Neutron Monitor	3,4,5	2	SR 3.3.1.6.3 SR 3.3.1.6.4 SR 3.3.1.6.6 SR 3.3.1.6.7
	6	2[(a)]	SR 3.3.1.6.1 SR 3.3.1.6.2 SR 3.3.1.6.4 SR 3.3.1.6.5 SR 3.3.1.6.7

(a) Only one SRNM channel is required to be OPERABLE during spiral offload or reload when the fueled region includes only that SRNM detector.

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

LCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required Automated Thermal Limit Monitor (ATLM) channel inoperable.	A.1 Restore the inoperable required ATLM channel to OPERABLE status.	7 days
B. One required Rod Worth Minimizer (RWM) channel inoperable.	B.1 Restore the inoperable required RWM channel to OPERABLE status.	7 days
C. One required Multi-Channel Rod Block Monitor (MRBM) channel inoperable.	C.1 Restore the inoperable required MRBM channel to OPERABLE status.	7 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met. <u>OR</u> Two required ATLM channels inoperable. <u>OR</u> Two required RWM channels inoperable. <u>OR</u> Two required MRBM channels inoperable.	D.1 Suspend control rod withdrawal.	Immediately
E. One or more required Reactor Mode Switch - Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal. <u>AND</u> E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.2.1-1 to determine which SRs apply for each Control Rod Block Function.

2. When a required ATLM, RWM, or MRBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	----------NOTE---------- Not required to be performed until one hour after THERMAL POWER is ≥ 30% RTP. ----------------------------- Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.2.1.2	----------NOTE---------- Not required to be performed until one hour after any control rod is withdrawn in MODE 2. ----------------------------- Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.2.1.3	----------NOTE---------- Not required to be performed until one hour after THERMAL POWER is ≤ 10% RTP. ----------------------------- Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.4	---------- NOTE ---------- Not required to be performed until one hour after THERMAL POWER is ≥ 30% RTP. ------------------------------- Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.2.1.5	Verify required RWM channels are not bypassed when THERMAL POWER is ≤ 10% RTP.	24 months
SR 3.3.2.1.6	Verify required ATLM channels are not bypassed when THERMAL POWER is ≥ 30% RTP.	24 months
SR 3.3.2.1.7	Verify required MRBM channels are not bypassed when THERMAL POWER is ≥ 30% RTP.	24 months
SR 3.3.2.1.8	---------- NOTE ---------- Not required to be performed until one hour after reactor mode switch is in shutdown position. ------------------------------- Perform CHANNEL FUNCTIONAL TEST on each required channel.	24 months
SR 3.3.2.1.9	Verify the bypassing and movement of control rods required to be bypassed in the Rod Action Control Subsystem (RACS) cabinets by a second licensed operator or other qualified member of the technical staff.	Prior to and during the movement of control rods bypassed in RACS

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS
1. Rod Control and Information System			
a. Automated Thermal Limit Monitor	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.6
b. Rod Worth Minimizer	1(b),2(b)	2	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.5 SR 3.3.2.1.9
c. Multi-Channel Rod Block Monitor	(a)	2	SR 3.3.2.1.4 SR 3.3.2.1.7
2. Reactor Mode Switch - Shutdown Position	(c)	2	SR 3.3.2.1.8

(a) THERMAL POWER ≥ 30% RTP.

(b) THERMAL POWER ≤ 10% RTP.

(c) Reactor mode switch in the shutdown position.

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3.3 INSTRUMENTATION

3.3.3.1 Remote Shutdown System

LCO 3.3.3.1 The Remote Shutdown System Functions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

------------------------------------ NOTE ------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable.	A.1 Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL FUNCTIONAL TEST on each required actuation channel.	24 months

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3.3 INSTRUMENTATION

3.3.3.2 Post-Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.2 Two channels of each Type A, B, and C PAM Instrumentation Function associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

NOTE

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required PAM Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.5.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more required PAM Functions with two required channels inoperable.	C.1 Restore one required channel to OPERABLE status.	7 days
	<u>OR</u>	
	C.2.1 Verify preplanned alternate method of monitoring the affected Function is available.	7 days
	<u>AND</u>	
	C.2.2 Initiate action in accordance with Specification 5.6.5.	7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.1	Perform CHANNEL CHECK on each required channel.	31 days
SR 3.3.3.2.2	Perform CHANNEL CALIBRATION on each required channel.	24 months

3.3 INSTRUMENTATION

3.3.4.1 Reactor Coolant System (RCS) Leakage Detection Instrumentation

LCO 3.3.4.1 The following RCS leakage detection instrumentation shall be OPERABLE:

a. Drywell floor drain high conductivity waste (HCW) sump monitoring system;

b. Particulate channel of the drywell fission product monitoring system; and

c. Drywell air coolers condensate flow monitoring system.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell floor drain HCW sump monitoring system inoperable.	A.1 Restore drywell floor drain HCW sump monitoring system to OPERABLE status.	30 days
B. Drywell fission product monitoring system particulate channel inoperable.	B.1 Analyze samples of drywell atmosphere.	Once per 12 hours
C. Drywell air coolers condensate flow monitoring systems inoperable.	----- NOTE ----- Not applicable when the drywell fission product monitoring system particulate channel is inoperable. -------------------	
	C.1 Perform SR 3.3.4.1.1.	8 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Drywell fission product monitoring system particulate channel inoperable.	D.1 Restore drywell fission product monitoring system particulate channel to OPERABLE status.	30 days
AND	OR	
Drywell air coolers condensate flow monitoring system inoperable.	D.2 Restore drywell air cooler condensate flow rate monitoring system to OPERABLE status.	30 days
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3.	12 hours
OR	AND	
All required LEAKAGE detection systems inoperable.	E.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL CHECK on required leakage detection instrumentation.	12 hours
SR 3.3.4.1.2	Perform CHANNEL FUNCTIONAL TEST on required leakage detection instrumentation.	31 days
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION on required leakage detection instrumentation.	24 months

3.3 INSTRUMENTATION

3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

LCO 3.3.5.1 Three ECCS instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.5.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5.1-1.

ACTIONS

NOTE

Separate Condition entry is allowed for each ECCS instrumentation channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Restore required channel to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with ECCS actuation capability not maintained.	B.1 Declare affected ECCS components inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

NOTE

Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Instrumentation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.3.5.1.4	Verify ECCS RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.5.1-1 (page 1 of 1)
Emergency Core Cooling System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	SURVEILLANCE REQUIREMENTS
1.	Reactor Vessel Water Level - Low, Level 1	1,2,3,4,5,6[(a)]	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.4
2.	Reactor Vessel Water Level - Low, Level 0.5	1,2,3,4,5,6[(a)]	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.4
3.	Drywell Pressure - High	1,2,3,4	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.4

(a) Except with the buffer pool gate removed and water level ≥ 7.01 meters (23.0 feet) over the top of the reactor pressure vessel flange.

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3.3 INSTRUMENTATION

3.3.5.2 Emergency Core Cooling System (ECCS) Actuation

LCO 3.3.5.2 Three ECCS actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.5.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5.2-1.

ACTIONS

------------------------------------NOTE------------------------------------

Separate Condition entry is allowed for each ECCS actuation Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required actuation division inoperable.	A.1 Restore required division to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with two or more required actuation divisions inoperable.	B.1 Declare affected actuation device(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.2.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.5.2.2	Verify ECCS RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.5.2-1 (page 1 of 1)
Emergency Core Cooling System Actuation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS
1.	Automatic Depressurization System (ADS)	1,2,3,4,5,6[(a)]
2.	Gravity-Driven Cooling System (GDCS) Injection Lines	1,2,3,4,5,6[(b)]
3.	Gravity-Driven Cooling System (GDCS) Equalizing Lines	1,2,3,4,5,6[(b)]
4.	Standby Liquid Control (SLC)	1,2,3,4

(a) Prior to removal of the reactor pressure vessel head.

(b) Except with the buffer pool gate removed and water level ≥ 7.01 meters (23.0 feet) over the top of the reactor pressure vessel flange.

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3.3 INSTRUMENTATION

3.3.5.3 Isolation Condenser System (ICS) Instrumentation

LCO 3.3.5.3 Three ICS instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for the Functions in Table 3.3.5.3-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.5.3-1.

ACTIONS

NOTE

Separate Condition entry is allowed for each ICS instrumentation channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Restore required channel to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with ICS actuation capability not maintained.	B.1 Declare ICS trains inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

NOTE
Refer to Table 3.3.5.3-1 to determine which SRs apply for each ICS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.3.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.5.3.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.5.3.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.3.5.3.4	Verify ICS RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.5.3-1 (page 1 of 1)
Isolation Condenser System (ICS) Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	SURVEILLANCE REQUIREMENTS
1.	Reactor Vessel Steam Dome Pressure - High	1,2,3,4,5	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4
2.	Reactor Vessel Water Level - Low, Level 2	1,2,3,4,5	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4
3.	Reactor Vessel Water Level - Low, Level 1	1,2,3,4,5	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4
4.	Main Steam Isolation Valve - Closure	1	SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4
5.	Power Generation Bus Loss	1	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4
6.	Condensate Return Valve - Open (per Isolation Condenser)	1,2,3,4,5	SR 3.3.5.3.2 SR 3.3.5.3.3

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3.3 INSTRUMENTATION

3.3.5.4 Isolation Condenser System (ICS) Actuation

LCO 3.3.5.4 Three ICS actuation logic divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.5.4-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each ICS actuation division.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required actuation division inoperable.	A.1 Restore required division to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with ICS actuation capability not maintained.	B.1 Declare affected actuation device(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

NOTE

Refer to Table 3.3.5.4-1 to determine which SRs apply for each ICS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.4.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.5.4.2	Verify ICS RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.5.4-1 (page 1 of 1)
Isolation Condenser System Actuation

FUNCTION	SURVEILLANCE REQUIREMENTS
1. ICS Initiation Actuation	SR 3.3.5.4.1 SR 3.3.5.4.2
2. ICS Vent Actuation	SR 3.3.5.4.1

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3.3 INSTRUMENTATION

3.3.6.1 Main Steam Isolation Valve (MSIV) Instrumentation

LCO 3.3.6.1 Three MSIV instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for the trip Functions in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

------------------------------------ NOTE ------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Verify associated instrument channel in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with MSIV isolation capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.6.1-1 for the associated Function.	Immediately
C. As required by Required Action B.1 and referenced in Table 3.3.6.1-1.	C.1 Be in MODE 2.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action B.1 and referenced in Table 3.3.6.1-1.	D.1 Declare associated MSIV(s) and main steam line drain isolation valve(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.6.1-1 to determine which SRs shall be performed for each isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.6.1.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.3.6.1.4	Verify ISOLATION SYSTEM RESPONSE TIME for each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.6.1-1 (page 1 of 1)
MSIV Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1.	Reactor Vessel Water Level - Low, Level 2	1,2,3,4	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
2.	Reactor Vessel Water Level - Low, Level 1	1,2,3,4	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
3.	Main Steam Line Pressure - Low	1	C	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
4.	Main Steam Line Flow - High (per Steam Line)	1,2,3,4	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
5.	Condenser Pressure – High (per condenser)	1	C	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
6.	Main Steam Tunnel Ambient Temperature - High	1,2,3,4	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4
7.	Main Steam Turbine Area Ambient Temperature - High	1,2,3,4	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.4

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3.3 INSTRUMENTATION

3.3.6.2 Main Steam Isolation Valve (MSIV) Actuation

LCO 3.3.6.2 Three MSIV actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each MSIV actuation division.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required MSIV actuation division inoperable.	A.1 Verify required MSIV actuation division in trip.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> MSIV actuation capability not maintained.	B.1 Declare affected actuation device(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.6.2.2	Verify ISOLATION SYSTEM RESPONSE TIME for each required division is within limits.	24 months on a STAGGERED TEST BASIS

3.3 INSTRUMENTATION

3.3.6.3 Isolation Instrumentation

LCO 3.3.6.3 Three isolation instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for the Functions in Table 3.3.6.3-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.3-1.

ACTIONS

- - - - - - - - - - - - - - - - - - NOTES - - - - - - - - - - - - - - - - - -

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each channel.

- -

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Restore required channel to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with isolation capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.6.3-1 for the associated Function.	Immediately
C. As required by Required Action B.1 and referenced in Table 3.3.6.3-1.	C.1 Declare associated containment isolation valves inoperable.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action B.1 and referenced in Table 3.3.6.3-1.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	12 hours 36 hours
E. As required by Required Action B.1 and referenced in Table 3.3.6.3-1.	E.1 Initiate action to restore required channel to OPERABLE status. <u>OR</u> E.2 Initiate action to isolate Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) isolation valves.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

NOTE

Refer to Table 3.3.6.3-1 to determine which SRs shall be performed for each isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.6.3.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.6.3.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.4	----------NOTE--------- Radiation detectors may be excluded. ---------------------- Verify ISOLATION SYSTEM RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.6.3-1 (page 1 of 2)
Isolation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1.	Reactor Vessel Water Level - Low, Level 2	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
		5,6	E	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
2.	Reactor Vessel Water Level - Low, Level 1	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
3.	Drywell Pressure - High	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
4.	Main Steam Tunnel Ambient Temperature - High	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
5.	RWCU/SDC Differential Mass Flow - High (per subsystem)	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
		5,6	E	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
6.	Isolation Condenser Steam Line Flow - High (per Isolation Condenser)	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
7.	Isolation Condenser Condensate Return Line Flow - High (per Isolation Condenser)	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
8.	Isolation Condenser Pool Vent Discharge Radiation - High (per Isolation Condenser)	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4

Table 3.3.6.3-1 (page 2 of 2)
Isolation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
9.	Depressurization Valve - Open	1,2,3,4	C	SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
10.	Feedwater Lines Differential Pressure - High	1,2,3,4	D	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
11.	Reactor Building Exhaust Radiation - High	1,2,3,4	C	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
12.	Drywell Water Level - High	1,2,3,4	D	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
13.	Reactor Vessel Water Level Low - Level 0.5	1,2,3,4	D	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
14.	Drywell Pressure High-High	1,2,3,4	D	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4
15.	Gravity-Driven Cooling System Pool Water Level - Low	1,2,3,4	D	SR 3.3.6.3.1 SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.4

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3.3 INSTRUMENTATION

3.3.6.4 Isolation Actuation

LCO 3.3.6.4 Three isolation actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for the Functions in Table 3.3.6.4-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.4-1.

ACTIONS

------------------------------------NOTES------------------------------------

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each isolation actuation division.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required isolation actuation divisions inoperable.	A.1 Restore required actuation division(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Isolation actuation capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.6.4-1 for the associated Function.	Immediately
C. As required by Required Action B.1 and referenced in Table 3.3.6.4-1.	C.1 Declare affected actuation device(s) inoperable.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action B.1 and referenced in Table 3.3.6.4-1.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	12 hours 36 hours
E. As required by Required Action B.1 and referenced in Table 3.3.6.4-1.	E.1 Initiate action to restore required division to OPERABLE status. OR E.2 Initiate action to isolate RWCU/SDC.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

NOTE

Refer to Table 3.3.6.4-1 to determine which SRs shall be performed for each isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.4.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.6.4.2	Verify ISOLATION SYSTEM RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.6.4.3	Perform a system functional test.	24 months

Table 3.3.6.4-1 (page 1 of 1)
Isolation Actuation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1.	Reactor Water Cleanup/Shutdown Cooling System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
		5,6	E	SR 3.3.6.4.1 SR 3.3.6.4.2 SR 3.3.6.4.3
2.	Isolation Condenser System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
3.	Process Radiation Monitoring System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
4.	Equipment and Floor Drain System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
5.	Containment Inerting System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
6.	Chilled Water System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
7.	Fuel and Auxiliary Pools Cooling System Process Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
8.	Reactor Building Heating, Ventilation and Air Conditioning System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
9.	High Pressure Nitrogen Gas Supply System Isolation	1,2,3,4	C	SR 3.3.6.4.1 SR 3.3.6.4.2
10.	Feedwater Isolation Valves Isolation	1,2,3,4	D	SR 3.3.6.4.1 SR 3.3.6.4.2 SR 3.3.6.4.3
11.	High Pressure Control Rod Drive Isolation	1,2,3,4	D	SR 3.3.6.4.1 SR 3.3.6.4.2 SR 3.3.6.4.3

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3.3 INSTRUMENTATION

3.3.7.1 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Instrumentation

LCO 3.3.7.1 Three CRHAVS instrumentation channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems – Shutdown," for each Function in Table 3.3.7.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

NOTE

Separate Condition entry is allowed for each CRHAVS instrumentation channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required instrumentation channel inoperable.	A.1 Restore required channel to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more functions with CRHAVS actuation capability not maintained.	B.1 Enter the Condition referenced in Table 3.3.7.1-1 for the associated function.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action B.1 and referenced in Table 3.3.7.1-1.	C.1.1 Isolate CRHA boundary.	Immediately
	<u>AND</u>	
	C.1.2 Place OPERABLE CRHAVS train in isolation mode.	Immediately
	<u>OR</u>	
	C.2 Declare CRHAVS train inoperable.	Immediately
D. As required by Required Action B.1 and referenced in Table 3.3.7.1-1.	D.1 Declare standby CRHAVS train inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.7.1-1 to determine which SRs apply for each CRHAVS Instrumentation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1.1	Perform CHANNEL CHECK on each required channel.	12 hours
SR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST on each required channel.	31 days
SR 3.3.7.1.3	Perform CHANNEL CALIBRATION on each required channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.7.1.4	----------NOTE--------- Radiation detectors may be excluded. --------------------- Verify CRHAVS RESPONSE TIME of each required channel is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.7.1-1 (page 1 of 1)
Control Room Habitability Area Heating, Ventilation, and Air Conditioning Subsystem (CRHAVS) Instrumentation

	FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION B.1	SURVEILLANCE REQUIREMENTS
1.	Control Room Air Intake Radiation – High-High	C	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4
2.	Extended Loss of AC Power	C	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4
3.	Emergency Filter Unit (EFU) Discharge Flow - Low (primary train)	D	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4
4.	EFU Outlet Radiation - High-High (primary train)	D	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4

3.3 INSTRUMENTATION

3.3.7.2 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Actuation

LCO 3.3.7.2 Three CRHAVS actuation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems – Shutdown," shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required actuation division inoperable.	A.1 Restore required division to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> CRHAVS actuation capability not maintained.	B.1.1 Isolate CRHA boundary. <u>AND</u> B.1.2 Place OPERABLE CRHAVS train in isolation mode. <u>AND</u> B.1.3 Declare remaining CRHAVS train inoperable. <u>OR</u> B.2 Declare affected actuation device(s) inoperable.	Immediately Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.7.2.1	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division.	24 months
SR 3.3.7.2.2	Verify CRHAVS RESPONSE TIME of each required division is within limits.	24 months on a STAGGERED TEST BASIS

3.3 INSTRUMENTATION

3.3.8.1 Diverse Protection System (DPS)

LCO 3.3.8.1 The DPS Functions in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

--------------------------------- NOTE ---------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DPS Functions inoperable.	A.1 Restore required DPS Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months

Table 3.3.8.1-1 (page 1 of 1)
Diverse Protection System

	FUNCTION	SURVEILLANCE REQUIREMENTS
1.	Automatic Depressurization System - Actuation	
	a. Reactor Vessel Level - Low, Level 1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
	b. Drywell Pressure - High (Manual Actuation)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
2.	Gravity–Driven Cooling System Injection Lines - Actuation	
	a. Reactor Vessel Level - Low, Level 1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
	b. Drywell Pressure - High (Manual Actuation)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
3.	Gravity–Driven Cooling System Equalizing Lines - Actuation	
	a. Reactor Vessel Level - Low (Manual Actuation)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
4.	Reactor Water Cleanup/Shutdown Cooling System Lines - Isolation	
	a. Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow - High	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4
5.	Isolation Condenser/Passive Containment Cooling System Expansion Pool to Equipment Pool Cross-Connect - Actuation	
	a. Isolation Condenser/Passive Containment Cooling System Pool Level - Low	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Safety Relief Valves (SRVs)

LCO 3.4.1 The safety mode of two SRVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required SRV inoperable.	A.1 Restore required SRV to OPERABLE status.	14 days
B. Required Action and associated Completion Time not met. <u>OR</u> Two required SRVs inoperable.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify the safety mode lift setpoints of the required SRVs are within 8.366 ± 0.251 MPaG (1213 ± 36.39 psig). Following testing, lift settings shall be within ± 1%.	In accordance with Inservice Testing Program

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3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Operational LEAKAGE

LCO 3.4.2 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. ≤ 19 L/min (5 gpm) unidentified LEAKAGE; and

c. ≤ 114 L/min (30 gpm) total LEAKAGE averaged over the previous 24-hour period.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS unidentified and total LEAKAGE are within limits.	12 hours

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3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Specific Activity

LCO 3.4.3 The specific activity of the reactor coolant shall be limited to DOSE EQUIVALENT I-131 specific activity ≤ 7400 Bq/gm (0.2 μCi/gm).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor coolant specific activity > 7400 Bq/gm (0.2 μCi/gm) and ≤ 148,000 Bq/gm (4.0 μCi/gm) DOSE EQUIVALENT I-131.	------NOTE------ LCO 3.0.4.c is applicable. ---------------	
	A.1 Determine DOSE EQUIVALENT I-131.	Once per 4 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limits.	48 hours
B. Required Action and associated Completion Time of Condition A not met. OR Reactor coolant specific activity > 148,000 Bq/gm (4.0 μCi/gm) DOSE EQUIVALENT I-131.	B.1 Determine DOSE EQUIVALENT I-131.	Once per 4 hours
	AND	
	B.2 Be in MODE 3.	12 hours
	AND	
	B.3 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTE---------- Only required to be performed in MODE 1. -------------------------------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is ≤ 7400 Bq/gm (0.2 μCi/gm).	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.4 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

STD COL 16.0-1-A 3.4.4-1

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
---------NOTE--------- Required Action A.2 shall be completed whenever this Condition is entered. ------------------------- A. Requirements of the LCO not met in MODES 1, 2, 3, and 4.	A.1 Restore parameter(s) to within limits. <u>AND</u> A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours
---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. ------------------------- C. Requirements of the LCO not met in other than MODES 1, 2, 3, and 4.	C.1 Initiate action to restore parameter(s) to within limits. <u>AND</u> C.2 Determine RCS is acceptable for operation.	Immediately Prior to entering MODE 2 or 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	---------- NOTE ---------- Only required to be met during RCS heatup and cooldown operations, and RCS inservice leak and hydrostatic testing. ----------------------	
STD COL 16.0-1-A 3.4.4-1	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes
SR 3.4.4.2 STD COL 16.0-1-A 3.4.4-1	Verify RCS pressure and RCS temperature are within the criticality limits specified in the PTLR.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.4.3	---------- NOTE ---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ----------------------	
STD COL 16.0-1-A 3.4.4-1	Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes
SR 3.4.4.4 STD COL 16.0-1-A 3.4.4-2	---------- NOTE ---------- Not required to be performed until 30 minutes after RCS temperature ≤ 26.7°C (80°F) in MODE 5. ----------------------	
STD COL 16.0-1-A 3.4.4-1	Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.4.5 STD COL 16.0-1-A 3.4.4-2 STD COL 16.0-1-A 3.4.4-1	----------NOTE---------- Not required to be performed until 12 hours after RCS temperature ≤ 37.8°C (100°F) in MODE 5. ------------------------------ Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	12 hours

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3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 Reactor Steam Dome Pressure

LCO 3.4.5 The reactor steam dome pressure shall be ≤ 7.17 MPaG (1040 psig).

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify reactor steam dome pressure is ≤ 7.17 MPaG (1040 psig).	12 hours

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3.5 Emergency Core Cooling Systems (ECCS)

3.5.1 Automatic Depressurization System (ADS) - Operating

LCO 3.5.1 The ADS function of ten Safety Relief Valves (SRVs) and eight Depressurization Valves (DPVs) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ADS valve with Diverse Protection System (DPS) initiator inoperable	A.1 Restore DPS initiator to OPERABLE status.	Prior to entering MODE 2 or 4 from MODE 5
B. Two or more ADS valves with DPS initiator inoperable.	B.1 Restore DPS initiator(s) to OPERABLE status.	30 days
C. One ADS valve inoperable for reasons other than Condition A.	C.1 Restore ADS valve to OPERABLE status.	14 days
D. Two or more ADS valves inoperable for reasons other than Condition A or B. OR Required Action and associated Completion Time of Condition A, B or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify High Pressure Nitrogen Supply System (HPNSS) supply pressure to SRVs is ≥ 2.41 MPaG (350 psig).	31 days
SR 3.5.1.2	----------NOTE--------- Not required to be met for one initiator intermittently disabled under administrative controls. ------------------------- Verify continuity of DPS initiator and two initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."	31 days
SR 3.5.1.3	----------NOTE--------- Valve actuation may be excluded. ------------------------- Verify the function of each SRV actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.1.4	----------NOTE--------- Squib actuation may be excluded. ------------------------- Verify each DPV actuates on an actual or simulated automatic initiation signal.	24 months

3.5 Emergency Core Cooling Systems (ECCS)

3.5.2 Gravity-Driven Cooling System (GDCS) - Operating

LCO 3.5.2 The following GDCS subsystems shall be OPERABLE:

a. Eight branch lines of the injection subsystem; and

b. Four trains of the equalizing subsystem.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more GDCS subsystems with one Diverse Protection System (DPS) initiator inoperable.	A.1 Restore DPS initiator(s) to OPERABLE status.	Prior to entering MODE 2 or 4 from MODE 5
B. One or more GDCS subsystems with two or more DPS initiators inoperable.	B.1 Restore DPS initiators to OPERABLE status.	30 days
C. One branch line of the injection subsystem inoperable for reasons other than Condition A or B.	C.1 Restore branch line of the injection subsystem to OPERABLE status.	14 days
D. One equalizing train inoperable for reasons other than Condition A or B.	D.1 Restore equalizing train to OPERABLE status.	14 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two or more branch lines of the injection subsystem inoperable for reasons other than Condition A or B. OR Two or more equalizing trains inoperable for reasons other than Condition A or B. OR Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify water level in each GDCS pool is ≥ 6.5 meters (21.3 feet).	12 hours
SR 3.5.2.2	------------NOTE------------ Not required to be met for one initiator intermittently disabled under administrative controls. ---------------------------- Verify continuity of DPS initiator and two initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	----------NOTE---------- Valve actuation may be excluded. ------------------------ Verify GDCS actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.2.4	----------NOTE---------- Valve actuation may be excluded. ------------------------ Verify the flow path for each GDCS injection branch line is not obstructed.	24 months on a STAGGERED TEST BASIS for each pair of injection branch lines.
SR 3.5.2.5	----------NOTE---------- Valve actuation may be excluded. ------------------------ Verify the flow path for each GDCS equalizing line is not obstructed.	24 months on a STAGGERED TEST BASIS for each equalizing line.

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3.5 Emergency Core Cooling Systems (ECCS)

3.5.3 Gravity-Driven Cooling System (GDCS) - Shutdown

LCO 3.5.3 The following GDCS subsystems shall be OPERABLE:

a. Two injection subsystem branch lines associated with each GDCS pool; and

b. Two equalizing subsystem trains.

APPLICABILITY: MODE 5,
MODE 6 except with the buffer pool gate removed and water level ≥ 7.01 meters (23.0 feet) over the top of the reactor pressure vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required injection subsystem branch line inoperable. <u>OR</u> One required equalizing subsystem train inoperable. <u>OR</u> One required Automatic Depressurization System (ADS) valve inoperable.	A.1 Restore required subsystems to OPERABLE status.	14 days
B. Two or more required injection subsystem branch lines inoperable.	B.1 Ensure capability of two methods of injecting a combined water volume equivalent to required GDCS pool volume.	4 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two required equalizing subsystem trains inoperable.	C.1 Ensure capability of two methods of injecting a combined water volume equivalent to required suppression pool volume.	4 hours
D. GDCS inoperable due to two or more required ADS valves inoperable.	D.1.1 Establish RCS vent path(s) with relief capacity equivalent to required ADS valves.	4 hours
	<u>OR</u>	
	D.1.2 Ensure capability of two methods of injecting a combined water volume equivalent to required GDCS and suppression pool volumes.	4 hours
	<u>AND</u>	
	D.2 Restore compliance with the LCO.	72 hours
E. GDCS inoperable for reasons other than Condition A, B, or C.	E.1 Ensure capability of two methods of injecting a combined water volume equivalent to required GDCS and suppression pool volumes.	4 hours from discovery of each Condition E entry
	<u>AND</u>	
	E.2 Restore compliance with the LCO.	72 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time not met.	F.1 Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
	<u>AND</u>	
	F.2.1 Initiate action to isolate reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas.	Immediately
	<u>OR</u>	
	F.2.2 Initiate action to establish reactor building REPAVS and CONAVS area automatic isolation capability on respective exhaust high radiation signals.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify water level in each GDCS pool is ≥ 6.5 meters (21.3 feet).	24 hours
SR 3.5.3.2	Verify suppression pool level is ≥ 5.4 meters (17.7 feet).	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.3	---------- NOTES ---------- 1. Only required to be met in MODE 5 and in MODE 6 prior to removal of the reactor pressure vessel head. 2. Only required to be met for safety relief valves (SRVs) as required to support relief capacity equivalent to 6 depressurization valves (DPVs). ------------------------------ Verify SRV accumulator supply pressure is ≥ 2.41 MPaG (350 psig).	31 days
SR 3.5.3.4	---------- NOTE ---------- Not required to be met for one initiator intermittently disabled under administrative controls. ------------------------------ Verify continuity of two initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems - Shutdown," for each required GDCS valve and for ADS valves required to support relief capacity equivalent to 6 DPVs.	31 days
SR 3.5.3.5	---------- NOTES ---------- 1. For ADS valves, only required to be met in MODE 5 and in MODE 6 prior to removal of the reactor pressure vessel head. 2. Valve actuation may be excluded. ------------------------------ Verify each required GDCS valve and ADS valve required to support relief capacity equivalent to 6 DPVs actuates on an actual or simulated automatic initiation signal.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.6	For GDCS injection branch lines and equalizing lines required to be OPERABLE, SRs 3.5.2.4 and 3.5.2.5 are applicable.	In accordance with applicable SRs

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3.5 Emergency Core Cooling Systems (ECCS)

3.5.4 Isolation Condenser System (ICS) - Operating

LCO 3.5.4 Four ICS trains shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODES 3 and 4 when < 2 hours since reactor was critical.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ICS train inoperable.	A.1 Restore ICS train to OPERABLE status.	14 days
B. Two or more ICS trains inoperable. <u>OR</u> Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	Verify each ICS train manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secure in position is in the correct position.	31 days
SR 3.5.4.2	Verify High Pressure Nitrogen Supply System (HPNSS) pressure to each nitrogen operated ICS valve is ≥ 1.13 MPaG (164 psig).	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.3	---------- NOTE ---------- Not required to be met for one initiator intermittently disabled under administrative controls. ------------------------------- Verify continuity of two initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."	31 days
SR 3.5.4.4	Verify each ICS subcompartment manual isolation valve is locked open.	24 months
SR 3.5.4.5	Verify ICS actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.4.6	Verify each ICS train is capable of removing the required heat load.	Prior to exceeding 25% RTP if not performed in the previous 24 months on a STAGGERED TEST BASIS

3.5 Emergency Core Cooling Systems (ECCS)

3.5.5 Isolation Condenser System (ICS) - Shutdown

LCO 3.5.5 Two ICS trains shall be OPERABLE.

APPLICABILITY: MODES 3 and 4 when ≥ 2 hours since reactor was critical,
MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required ICS trains inoperable.	A.1 Initiate action to restore required ICS trains to OPERABLE status.	Immediately
	<u>AND</u>	
	A.2 Verify an alternate method of decay heat removal is available for each inoperable required ICS train.	1 hour <u>AND</u> Once per 24 hours thereafter
	<u>AND</u>	
	A.3 Verify at least one method of decay heat removal is in operation.	1 hour <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	A.4 Monitor reactor coolant temperature and pressure.	Once per hour

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Initiate action to isolate reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas.	Immediately
	<u>OR</u>	
	B.2 Initiate action to establish reactor building REPAVS and CONAVS area automatic isolation capability on respective exhaust high radiation signals.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	Verify each ICS train manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secure in position is in the correct position or can be aligned to the correct position.	31 days
SR 3.5.5.2	Verify High Pressure Nitrogen Supply System (HPNSS) pressure to each nitrogen operated ICS valve is ≥ 1.13 MPaG (164 psig).	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.3	----------NOTE---------- Not required to be met for one initiator intermittently disabled under administrative controls. ----------------------------- Verify continuity of two initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown."	31 days
SR 3.5.5.4	Verify required ICS pool subcompartment manual isolation valves are locked open.	24 months
SR 3.5.5.5	Verify ICS actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.5.6	For ICS trains required to be OPERABLE, SR 3.5.4.6 is applicable.	In accordance with SR 3.5.4.6

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3.6 CONTAINMENT SYSTEMS

3.6.1.1 Containment

LCO 3.6.1.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with Containment Leakage Rate Testing Program.	In accordance with Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify combined feedwater flow isolation valve pathway inleakage is $<$ 900 cc per min (0.238 gpm) when tested at $\geq$ 450 and $\leq$ 500 kPa ($\geq$ 66 and $\leq$ 73 psi).	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.3	----------NOTE---------- Performance of SR 3.6.1.1.5 satisfies this surveillance. ------------------------------ Verify each wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve leakage is ≤ 15% of design basis $A/\sqrt{K}$.	24 months
SR 3.6.1.1.4	----------NOTE---------- Performance of SR 3.6.1.1.5 satisfies this surveillance. ------------------------------ Verify total wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve pathway leakage is ≤ 35% of design basis $A/\sqrt{K}$.	24 months
SR 3.6.1.1.5	Verify overall suppression pool bypass leakage is ≤ 50% of design basis $A/\sqrt{K}$.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.1.2 Containment Air Lock

LCO 3.6.1.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTES------------------------------------

1. Entry and exit are permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate acceptance criteria.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	-----NOTES----- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit are permissible under the control of a dedicated individual. ---------------	
	A.1 Verify the OPERABLE door is closed in the affected air lock.	1 hour
	AND	
	A.2 Lock the OPERABLE door closed in the affected air lock.	24 hours
	AND	
	A.3 -----NOTE----- Air Lock Doors in high radiation areas may be verified locked closed by administrative means. ------------ Verify the OPERABLE door is locked closed in the affected airlock.	Once per 31 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	- - - - - NOTES - - - - - 1. Required Actions B.1, B.2 and B.3 are not applicable if both doors in the same airlock are inoperable and Condition C entered. 2. Entry and exit are permissible under the control of a dedicated individual. - - - - - - - - - - - - - -	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	B.3 - - - - NOTE - - - - - Air Lock Doors in high radiation areas may be verified locked closed by administrative means. - - - - - - - - - - - -	
	Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate containment overall leakage rate per LCO 3.6.1.1, using current air lock test results.	Immediately
	<u>AND</u>	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	C.3 Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	D.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	------------NOTES------------ 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1.1. ------------------------------ Perform required containment air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.1.2.2	Verify only one door in the containment air lock can be opened at a time.	24 months

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3.6 CONTAINMENT SYSTEMS

3.6.1.3 Containment Isolation Valves (CIVs)

LCO 3.6.1.3 Each CIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTES------------------------------------

1. Penetration flow paths may be opened intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for supported systems made inoperable by CIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Containment," when CIV leakage results in exceeding overall containment leakage rate acceptance criteria in MODES 1, 2, 3, and 4.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more reactor water cleanup/ shutdown cooling (RWCU/SDC) system penetration flow path(s) diverse protection system (DPS) initiator inoperable.	A.1 Restore DPS initiator to OPERABLE status.	30 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more penetration flow paths with one CIV inoperable for reasons other than Condition A or D.	B.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, check valve with flow secured, or blind flange.	4 hours except for main steam line AND 8 hours for main steam line
	AND	
	B.2 Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment AND Prior to entering MODE 2 or 4 from MODE 5, if containment was de-inerted while in MODE 5, if not performed within the previous 92 days, for isolation devices inside containment
C. One or more penetration flow paths with two or more CIVs inoperable for reasons other than Condition A or D.	C.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, or blind flange.	1 hour
D. MSIV leakage rate or feedwater line leakage rate not within limit.	D.1 Restore leakage rate to within limit.	8 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	---------- NOTE ---------- Not required to be met when the containment purge valves are open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. ------------------------------- Verify each containment purge valve is closed.	31 days
SR 3.6.1.3.2	---------- NOTE ---------- Not required to be met on CIVs that are open under administrative controls. ------------------------------- Verify each manual CIV and blind flange that is located outside containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.3	----------NOTE---------- Not required to be met for one initiator circuit intermittently disabled under administrative controls. ---------------------- Verify continuity for each automatic CIV of: a. Required safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for each CIV; and b. DPS initiator for each RWCU/SDC CIV.	31 days
SR 3.6.1.3.4	----------NOTE---------- Not required to be met on CIVs that are open under administrative controls. ---------------------- Verify each manual CIV and blind flange that is located inside containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	Prior to entering MODE 2 or 4 from MODE 5 if containment was de-inerted while in MODE 5, if not performed within the previous 92 days
SR 3.6.1.3.5	Verify the isolation time of each power operated automatic CIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program
SR 3.6.1.3.6	Verify the full closure isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.7	Verify each automatic CIV actuates to the isolation position on an actual or simulated isolation signal.	24 months
SR 3.6.1.3.8	Verify a representative sample of reactor instrumentation line excess flow check valves actuate on a simulated instrument line break to restrict flow.	24 months
SR 3.6.1.3.9	Verify combined MSIV leakage rate through all four main steam lines is ≤ 1.57 E-03 standard m^3/sec (200 scfh) when tested at ≥ P_a.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.1.3.10	Verify combined feedwater isolation valve leakage rate through both feedwater lines is ≤ 7.00E-04 standard m^3/min (2.47E-02 scfm) when tested at P_a.	In accordance with the Containment Leakage Rate Testing Program

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3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Pressure

LCO 3.6.1.4 Drywell pressure shall be ≤ 106.9 kPa (15.5 psia).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell pressure not within limit.	A.1 Restore drywell pressure to within limit.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.4.1	Verify drywell pressure is within limit.	12 hours

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3.6 CONTAINMENT SYSTEMS

3.6.1.5 Drywell Air Temperature

LCO 3.6.1.5 Drywell average air temperature shall be ≤ 65.5°C (150°F).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1 Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.5.1 Verify drywell average air temperature is within limit.	24 hours

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3.6 CONTAINMENT SYSTEMS

3.6.1.6 Wetwell-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Two wetwell-to-drywell vacuum breaker flow paths shall be OPERABLE for opening.

AND

Three wetwell-to-drywell vacuum breaker flow path isolation functions shall be OPERABLE, with each vacuum breaker closed except when performing its intended function.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required wetwell-to-drywell vacuum breaker inoperable for opening. OR One required wetwell-to-drywell vacuum breaker isolation valve not open.	A.1 Restore required wetwell-to-drywell vacuum breaker flow path to OPERABLE for opening status.	7 days
B. One wetwell-to-drywell vacuum breaker not closed. OR One wetwell-to-drywell vacuum breaker flow path isolation function inoperable.	B.1 Isolate affected wetwell-to-drywell vacuum breaker flow path.	8 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One wetwell-to-drywell vacuum breaker not closed. AND Associated wetwell-to-drywell vacuum breaker flow path isolation function inoperable	C.1 Isolate the affected wetwell-to-drywell vacuum breaker flow path.	1 hour
D. Two required wetwell-to-drywell vacuum breaker flow paths inoperable.	D.1 Restore one required wetwell-to-drywell vacuum breaker flow path to OPERABLE status.	1 hour
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	Verify each vacuum breaker is closed.	14 days
SR 3.6.1.6.2	Verify each required vacuum breaker isolation valve is open.	31 days
SR 3.6.1.6.3	Verify each required vacuum breaker opens at ≤ 3.07 kPaD (0.445 psid).	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.4	Perform CHANNEL CALIBRATION of each vacuum breaker flow path isolation function consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.6.1.6.5	Perform a system functional test of each vacuum breaker flow path isolation function.	24 months

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3.6 CONTAINMENT SYSTEMS

3.6.1.7 Passive Containment Cooling System (PCCS)

LCO 3.6.1.7 Six PCCS condensers shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PCCS condensers inoperable.	A.1 Restore PCCS condensers to OPERABLE status.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	Verify that the spectacle flanges for the vent and drain line for each PCCS condenser are in the free flow position.	Prior to entering MODE 2 or 4 from MODE 5 if containment was de-inerted while in MODE 5, if not performed within the previous 92 days
SR 3.6.1.7.2	Verify each PCCS subcompartment manual isolation valve is locked open.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.3	Verify that both modules in each PCCS condenser have an unobstructed path from the drywell inlet through the condenser tubes to the following: a. the GDCS pool through the drain line; and b. the suppression pool through the vent line.	24 months on a STAGGERED TEST BASIS for each PCCS condenser
SR 3.6.1.7.4	Visually examine each PCCS vent catalyst module and verify there is no evidence of abnormal conditions.	24 months on a STAGGERED TEST BASIS for each PCCS condenser
SR 3.6.1.7.5	Verify performance of a representative sample of PCCS vent catalyst module plates.	24 months on a STAGGERED TEST BASIS for each PCCS condenser

3.6 CONTAINMENT SYSTEMS

3.6.1.8 Containment Oxygen Concentration

LCO 3.6.1.8 Containment oxygen concentration shall be < 4.0 volume percent.

APPLICABILITY: During the time period:

a. From 24 hours after THERMAL POWER > 15% RTP following startup,

b. Until 24 hours prior to THERMAL POWER ≤ 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment oxygen concentration not within limit.	A.1 Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.8.1 Verify containment oxygen concentration is within limit.	7 days

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3.6 CONTAINMENT SYSTEMS

3.6.2.1 Suppression Pool Average Temperature

LCO 3.6.2.1 Suppression pool average temperature shall be:

a. ≤ 43.3°C (110°F) with THERMAL POWER > 1% of RTP, and no testing that adds heat to the suppression pool is being performed.

b. ≤ 46.1°C (115°F) with THERMAL POWER > 1% of RTP and testing that adds heat to the suppression pool is being performed.

c. ≤ 48.9°C (120°F) with THERMAL POWER ≤ 1% of RTP.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool average temperature > 43.3°C (110°F) but ≤ 48.9°C (120°F). <u>AND</u> THERMAL POWER > 1% RTP. <u>AND</u> Not performing testing that adds heat to the suppression pool.	A.1 Verify suppression pool average temperature is ≤ 48.9°C (120°F). <u>AND</u> A.2 Restore suppression pool average temperature to ≤ 43.3°C (110°F).	Once per hour 24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to ≤ 1% RTP.	12 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Suppression pool average temperature > 46.1°C (115°F). AND THERMAL POWER > 1% RTP. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 48.9°C (120°F).	D.1 Place the reactor mode switch in the shutdown position. AND D.2 Determine suppression pool average temperature. AND D.3 Be in MODE 5.	Immediately Once per 30 minutes 36 hours
E. Suppression pool average temperature > 54.4°C (130°F).	E.1 Be in MODE 5.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 5.4 meters (17.7 feet) and ≤ 5.5 meters (18.0 feet).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool water level not within limits.	A.1 Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.2.2.1 Verify suppression pool water level is within limits.	24 hours

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3.6 CONTAINMENT SYSTEMS

3.6.3.1 Reactor Building (Contaminated Area Ventilation Subsystem (CONAVS) Area)

LCO 3.6.3.1 The Reactor Building (CONAVS area) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTES------------------------------------

1. Reactor Building (CONAVS area) boundary may be opened intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one Reactor Building (CONAVS area) boundary isolation damper inoperable.	A.1 Isolate the affected flow path by use of at least one closed and de-activated automatic damper, closed manual damper, or blind flange.	7 days
	<u>AND</u>	
	A.2 Verify the affected penetration flow path is isolated.	Once per 31 days
B. One or more penetration flow paths with two Reactor Building (CONAVS area) boundary isolation dampers inoperable.	B.1 Isolate the affected flow path by use of at least one closed and de-activated automatic damper, closed manual damper, or blind flange.	48 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Reactor Building (CONAVS area) inoperable for reasons other than Condition A or B.	C.1 Restore Reactor Building to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify all Reactor Building (CONAVS area) equipment hatches are closed.	31 days
SR 3.6.3.1.2	Verify one Reactor Building (CONAVS area) access door in each access opening is closed, except when the access opening is being used for entry and exit.	31 days
SR 3.6.3.1.3	---------- NOTE ---------- Not required to be met for one initiator circuit intermittently disabled under administrative controls. ------------------------- Verify continuity of required safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for each Reactor Building boundary isolation damper.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.4	Verify Reactor Building (CONAVS area) boundary isolation dampers actuate on an actual or simulated isolation signal.	24 months
SR 3.6.3.1.5	Verify Reactor Building (CONAVS area) exfiltration rate within limits.	24 months

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3.7 PLANT SYSTEMS

3.7.1 Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools

LCO 3.7.1 The IC/PCCS pools shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both IC/PCCS expansion pools with one equipment pool cross-connect valve Diverse Protection System (DPS) initiator inoperable.	A.1 Restore DPS initiator(s) to OPERABLE status.	Prior to entering MODE 2 or 4 from MODE 5
B. One or both IC/PCCS expansion pools with both equipment pool cross-connect valve DPS initiators inoperable.	B.1 Restore DPS initiator(s) to OPERABLE status.	30 days
C. One or both IC/PCCS expansion pools with one equipment pool connection line inoperable for reasons other than Condition A.	C.1 Restore IC/PCCS expansion pool-to-equipment pool line(s) to OPERABLE status.	30 days
D. One required IC/PCCS expansion pool level instrumentation channel inoperable.	D.1 Restore required channel to OPERABLE status.	20 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One required IC/PCCS expansion pool-to equipment pool cross-connect actuation logic division inoperable.	E.1 Restore required division to OPERABLE status.	20 hours
F. IC/PCCS pool inoperable for reasons other than Condition A, B, C, D, or E.	F.1 Restore IC/PCCS pools to OPERABLE status.	8 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Perform CHANNEL CHECK on each required IC/PCCS expansion pool level instrumentation channel.	12 hours
SR 3.7.1.2	Verify water levels in the IC/PCCS expansion pools are ≥ 4.8 meters (15.75 feet).	24 hours
SR 3.7.1.3	- - - - - - - - - NOTE - - - - - - - - - Not required to be met in Modes 3 and 4. - Verify water levels in the equipment pool and reactor well are ≥ 6.7 meters (22.0 feet).	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.4	Verify average water temperature in available IC/PCCS pools is ≤ 43.3°C (110°F).	24 hours
SR 3.7.1.5	Verify supply pressure to each IC/PCCS expansion pool-to-equipment pool cross-connect valve accumulator is ≥ 0.62 MPaG (90 psig).	31 days
SR 3.7.1.6	---------- NOTE ---------- Not required to be met for one initiator intermittently disabled under administrative controls. ------------------------------ Verify continuity of DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for each IC/PCCS expansion pool-to-equipment pool cross-connect valve.	31 days
SR 3.7.1.7	Perform CHANNEL FUNCTIONAL TEST on each required IC/PCCS expansion pool level instrumentation channel.	31 days
SR 3.7.1.8	Verify the manual isolation valve on each expansion pool-to-equipment pool line and between each IC/PCCS expansion pool partition is locked open.	24 months
SR 3.7.1.9	---------- NOTE ---------- Not required to be met in MODES 3 and 4. ------------------------------ Verify the reactor well-to-equipment pool gate is not installed.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.10	---------- NOTES ---------- 1. Valve actuation may be excluded. 2. Not required to be met in MODES 3 and 4. -------------------------- Verify each IC/PCCS expansion pool-to-equipment pool cross-connect valve actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.7.1.11	Perform CHANNEL CALIBRATION on each required IC/PCCS expansion pool level instrumentation channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.7.1.12	Perform LOGIC SYSTEM FUNCTIONAL TEST on each required division of the IC/PCCS expansion pool-to-equipment pool cross-connect actuation logic.	24 months
SR 3.7.1.13	Verify each IC/PCCS pool subcompartment has an unobstructed path through moisture separator to the atmosphere.	48 months on a STAGGERED TEST BASIS for the flow path associated with each moisture separator

3.7 PLANT SYSTEMS

3.7.2 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)

LCO 3.7.2 Two CRHAVS trains associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating," and LCO 3.8.7, "Distribution Systems – Shutdown," shall be OPERABLE.

- - - - - - - - - - - - - - NOTE - - - - - - - - - - - - - -
The control room habitability area (CRHA) boundary may be opened intermittently under administrative control.
- -

APPLICABILITY: MODES 1, 2, 3, and 4,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more CRHA heat sink(s) with average temperature not within limit.	A.1 Restore each CRHA heat sink average air temperature to within limit.	8 hours
	<u>AND</u>	
	A.2 Restore each CRHA heat sink average temperature to within limits.	24 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more CRHAVS trains inoperable due to inoperable CRHA boundary.	B.1 Initiate action to implement mitigating actions. AND B.2 Verify mitigating actions ensure CRHA occupant exposures to radiological and smoke hazards will not exceed limits. AND B.3 Restore CRHA boundary to OPERABLE status.	Immediately 24 hours 90 days
C. One CRHAVS train inoperable for reasons other than Condition A or B.	C.1 Restore CRHAVS train to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition A, B, or C not met in MODE 1, 2, 3, or 4. OR Two CRHAVS trains inoperable in MODE 1, 2, 3, or 4 for reasons other than Condition A or B.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	12 hours 36 hours

NAPS COL 16.0-1-A
3.7.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition A or B not met during OPDRVs. OR Two CRHAVS trains inoperable during OPDRVs for reasons other than Condition A or B.	E.1 Initiate action to suspend OPDRVs.	Immediately
F. Required Action and associated Completion Time of Condition C not met during OPDRVs.	F.1 Place OPERABLE CRHAVS train in isolation mode. OR F.2 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify average temperature of each CRHA heat sink is within established design limits.	24 hours
SR 3.7.2.2	Operate each CRHAVS train for ≥ 15 minutes.	31 days
SR 3.7.2.3	Perform required CRHAVS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.4	Verify each CRHAVS train actuates on an actual or simulated initiation signal.	24 months
SR 3.7.2.5	Verify de-energization of the main control room Nonsafety-Related Distributed Control and Information System (N-DCIS) electrical loads on an actual or simulated initiation signal.	24 months
SR 3.7.2.6	Perform CHANNEL CALIBRATION of main control room temperature instrumentation channels consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months
SR 3.7.2.7	Perform required CRHA unfiltered air inleakage testing in accordance with the Control Room Habitability Area (CRHA) Boundary Program.	In accordance with the CRHA Boundary Program

3.7 PLANT SYSTEMS

3.7.3 Main Condenser Offgas

LCO 3.7.3 The gross gamma activity rate of the noble gases measured at the offgas recombiner effluent shall be ≤ 16700 MBq/s (450 mCi/second) after decay of 30 minutes.

APPLICABILITY: MODE 1,
MODES 2, 3, and 4 with any main steam line not isolated and steam jet air ejector (SJAE) in operation.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Gross gamma activity rate of the noble gases not within limit.	A.1 Restore gross gamma activity rate of the noble gases to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Isolate all main steam lines.	12 hours
	<u>OR</u>	
	B.2 Isolate SJAE.	12 hours
	<u>OR</u>	
	B.3.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	B.3.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	---------- NOTE ---------- Not required to be performed until 31 days after any main steam line not isolated and SJAE in operation. ----------------------------- Verify the gross gamma activity rate of the noble gases is ≤ 16700 MBq/s (450 mCi/second) after decay of 30 minutes.	31 days AND Once within 4 hours after a ≥ 50% increase in the nominal steady state fission gas release after factoring out increases due to changes in THERMAL POWER level

3.7 PLANT SYSTEMS

3.7.4 Main Turbine Bypass System

LCO 3.7.4 The Main Turbine Bypass System shall be OPERABLE.

STD COL 16.0-1-A 3.7.4-1

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each main turbine bypass valve.	31 days
SR 3.7.4.2	Perform a system functional test.	24 months
SR 3.7.4.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	24 months

STD COL 16.0-1-A 3.7.4-2

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3.7 PLANT SYSTEMS

3.7.5 Fuel Pool Water Level and Temperature

LCO 3.7.5 The fuel pool water level and temperature shall be within limits.

APPLICABILITY: During movement of irradiated fuel assemblies in the associated fuel storage pool,
When irradiated fuel assemblies are stored in the associated fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel pool water level or temperature not within limit.	------NOTE------ LCO 3.0.3 is not applicable. ---------------	
	A.1 Suspend movement of irradiated fuel assemblies in the associated fuel storage pool(s).	Immediately
	AND	
	A.2 Initiate action to restore water level and temperature to within limit.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify the fuel pool water level is ≥ 10.26 m (33.7 ft) over the top of irradiated fuel assemblies seated in the storage racks.	7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.2	Verify the fuel pool average water temperature is ≤ 60°C (140°F).	7 days

3.7 PLANT SYSTEMS

3.7.6 Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions

LCO 3.7.6 The Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) functions shall be OPERABLE.

STD COL 16.0-1-A 3.7.6-1

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify each SCRRI and SRI control rod required in accordance with the COLR is OPERABLE in accordance with the SRs for LCO 3.1.3, "Control Rod OPERABILITY."	According to the SRs for LCO 3.1.3
SR 3.7.6.2	Verify correct breaker alignment and indicated power availability for each SCRRI control rod fine motion control rod drive (FMCRD) required in accordance with the COLR.	7 days
SR 3.7.6.3	Perform a system functional test for the SCRRI function.	24 months

SURVEILLANCE REQUIREMENTS

SR 3.7.6.4	Perform a system functional test for the SRI function.	24 months
SR 3.7.6.5	Verify FMCRD electrical insertion rate over the required insertion range for each SCRRI control rod required in accordance with the COLR is within limits.	24 months
SR 3.7.6.6	Perform CHANNEL CALIBRATION of loss-of-feedwater-heating instrumentation channels consistent with Specification 5.5.11, "Setpoint Control Program (SCP)."	24 months

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 DC Sources - Operating

LCO 3.8.1 DC Sources shall be OPERABLE to support the three Divisions of DC and Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution Systems – Operating."

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC source on one required division inoperable.	A.1 Restore required DC source to OPERABLE status.	72 hours
B. Two DC Sources on one required division inoperable.	B.1 Restore one required DC Source to OPERABLE status.	8 hours
C. One or more DC Sources inoperable on two or more required divisions. OR Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify each required battery terminal voltage is greater than or equal to the minimum established float voltage.	7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.2	Verify each required battery charger supplies ≥ 500 amps at greater than or equal to the minimum established float voltage for ≥ 8 hours. <u>OR</u> Verify each required battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	24 months
SR 3.8.1.3	Verify each required battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	24 months
SR 3.8.1.4	Verify the output diode for each required battery charger and safety-related rectifier connected to the Isolation Power Center bus prevents reverse current flow.	24 months
SR 3.8.1.5	Verify each required DC Source can supply the 120 VAC Uninterruptible AC Power inverter for ≥ 4 hours.	24 months

STD COL 16.0-1-A 3.8.1-1

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 DC Sources - Shutdown

LCO 3.8.2 DC Sources shall be OPERABLE to support the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC source on one required division inoperable.	A.1 Restore required DC Source to OPERABLE status.	72 hours
B. Two or more required DC Sources inoperable. OR Required Action and associated Completion Time of Condition A not met.	B.1 Declare affected required features inoperable.	Immediately
	OR	
	B.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	B.2.2 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	B.2.3 Initiate action to restore required DC Sources to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	For DC Sources required to be OPERABLE the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.2 SR 3.8.1.3 SR 3.8.1.4 SR 3.8.1.5	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Battery Parameters

LCO 3.8.3 Battery parameters shall be within limits.

APPLICABILITY: When associated DC Sources are required to be OPERABLE.

ACTIONS

-- NOTE --
Separate Condition entry allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
STD COL 16.0-1-A 3.8.3-3 A. One or two batteries on one required division with one or more battery cells float voltage < 2.09 V.	A.1 Perform SR 3.8.1.1. AND A.2 Perform SR 3.8.3.1. AND A.3 Restore affected cell voltage ≥ 2.09 V.	2 hours 2 hours 24 hours
STD COL 16.0-1-A 3.8.3-1 B. One battery on one required division with float current > 30 amps.	B.1 Perform SR 3.8.1.1. AND B.2 Restore battery float current ≤ 30 amps.	2 hours 24 hours
STD COL 16.0-1-A 3.8.3-1 C. Two batteries on one required division with float current > 30 amps.	C.1 Perform SR 3.8.1.1. AND C.2 Restore one battery float current ≤ 30 amps.	2 hours 8 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
---- NOTE ------ Required Action D.2 shall be completed if electrolyte level was below the top of plates. -------------	------ NOTE------ Required Actions D.1 and D.2 are only applicable if electrolyte level was below the top of plates. --------------	
D. One or two batteries on one required division with one or more cell electrolyte level(s) less than minimum established design limits.	D.1 Restore electrolyte level to above top of plates.	8 hours
	<u>AND</u>	
	D.2 Verify no evidence of leakage.	12 hours
	<u>AND</u>	
	D.3 Restore electrolyte level to greater than or equal to minimum established design limits.	31 days
E. One or two batteries on one required division with battery pilot cell electrolyte temperature less than minimum established design limit.	E.1 Restore battery pilot cell electrolyte temperature to greater than or equal to minimum established design limit.	12 hours
F. One or more required batteries in redundant required divisions with battery parameters not within limits.	F.1 Restore battery parameters in all but one required division to within limits.	2 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition A, B, C, D, E or F not met. OR Required battery with one or more battery cell float voltage < 2.09 V and float current > 30 amps. STD COL 16.0-1-A 3.8.3-3 STD COL 16.0-1-A 3.8.3-1	G.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	---NOTE--- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.1.1. ------ STD COL 16.0-1-A 3.8.3-1 Verify each required battery float current ≤ 30 amps.	7 days
SR 3.8.3.2 STD COL 16.0-1-A 3.8.3-3	Verify each required battery pilot cell float voltage is ≥ 2.09 V.	31 days
SR 3.8.3.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	31 days
SR 3.8.3.4	Verify each required battery pilot cell electrolyte temperature is greater than or equal to minimum established design limit.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.5 STD COL 16.0-1-A 3.8.3-3	Verify each required battery connected cell float voltage is ≥ 2.09 V.	92 days
SR 3.8.3.6 STD COL 16.0-1-A 3.8.3-4	Verify each required battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test.	60 months AND 12 months when battery shows degradation or has reached 85% of the expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 Inverters - Operating

LCO 3.8.4 Inverters shall be OPERABLE to support the three Divisions of Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution Systems – Operating."

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One inverter on one required division inoperable.	A.1 Restore required inverter to OPERABLE status.	72 hours
B. Two inverters on one required division inoperable.	B.1 Restore one required inverter to OPERABLE status.	8 hours
C. Two or more required divisions inoperable. OR Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify correct inverter voltage, frequency, and alignment to each required uninterruptible AC bus.	7 days

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3.8 ELECTRICAL POWER SYSTEMS

3.8.5 Inverters - Shutdown

LCO 3.8.5 Inverters shall be OPERABLE to support the Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One inverter on one required division inoperable.	A.1 Restore required inverter to OPERABLE status.	72 hours
B. Two or more required inverters inoperable. OR Required Action and associated Completion Time of Condition A not met.	B.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	B.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	B.2.2 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	B.2.3 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	Verify correct inverter voltage, frequency, and alignment to each required uninterruptible AC bus.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Distribution Systems - Operating

LCO 3.8.6 Three Divisions of DC and Uninterruptible AC Electrical Power Distribution shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC Electrical Power Distribution bus on one required division inoperable.	A.1 Restore required DC Electrical Power Distribution bus to OPERABLE status.	72 hours
B. Two DC Electrical Power Distribution buses on one required division inoperable.	B.1 Restore one required DC Electrical Power Distribution bus to OPERABLE status.	8 hours
C. One Uninterruptible AC Electrical Power Distribution bus on one required division inoperable.	C.1 Restore required Uninterruptible AC Electrical Power Distribution bus to OPERABLE status.	72 hours
D. Two Uninterruptible AC Electrical Power Distribution buses on one required division inoperable.	D.1 Restore one required Uninterruptible AC Electrical Power Distribution bus to OPERABLE status.	8 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Uninterruptible AC Electrical Power Distribution bus on one required division inoperable. AND DC Electrical Power Distribution bus associated with the redundant Uninterruptible AC Electrical Power Distribution bus on the same required division inoperable.	E.1 Restore required Uninterruptible AC Electrical Power Distribution bus to OPERABLE status. OR E.2 Restore required DC Electrical Power Distribution bus to OPERABLE status.	8 hours 8 hours
F. Two or more required divisions of DC and Uninterruptible AC Electrical Power Distribution inoperable. OR Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify correct breaker alignments and voltage to required DC and Uninterruptible AC Electrical Power Distribution buses.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems - Shutdown

LCO 3.8.7 The necessary portions of DC and Uninterruptible AC Electrical Power Distribution shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC Electrical Power Distribution bus on one required division inoperable.	A.1 Restore required DC Electrical Power Distribution bus to OPERABLE status.	72 hours
B. One Uninterruptible AC Electrical Power Distribution bus on one required division inoperable.	B.1 Restore required Uninterruptible AC Electrical Power Distribution bus to OPERABLE status.	72 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two or more required DC Electrical Power Distribution buses inoperable. OR Two or more required Uninterruptible AC Electrical Power Distribution buses inoperable. OR One interruptible AC Electrical Power Distribution bus and the DC Electrical Power Distribution bus associated with the redundant Uninterruptible AC Electrical Power Distribution bus on the same required division inoperable. OR Required Action and associated Completion Time of Condition A or B not met.	C.1 Declare associated supported required feature(s) inoperable.	Immediately
	OR	
	C.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	C.2.2 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	C.2.3 Initiate actions to restore required divisions of DC and Uninterruptible AC Electrical Power Distribution to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and voltage to required DC and Uninterruptible AC Electrical Power Distribution buses.	7 days

3.9 REFUELING OPERATIONS

3.9.1 Refueling Equipment Interlocks

LCO 3.9.1 The refueling equipment interlocks associated with the reactor mode switch Refuel position shall be OPERABLE.

APPLICABILITY: During in-vessel fuel movement with equipment associated with the interlocks when the reactor mode switch is in Refuel position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required refueling equipment interlocks inoperable.	A.1 Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s).	Immediately
	<u>OR</u>	
	A.2.1 Insert a control rod withdrawal block.	Immediately
	<u>AND</u>	
	A.2.2 Verify all control rods are fully inserted.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform a CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in; b. Refueling machine position; c. Refueling machine fuel grapple hoist, fuel loaded; and d. Refueling machine auxiliary hoist, fuel-loaded.	7 days

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod/Rod-Pair-Out Interlock

LCO 3.9.2 The refuel position one-rod/rod-pair-out interlock shall be OPERABLE.

APPLICABILITY: MODE 6 with the reactor mode switch in the refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refuel position one rod/rod-pair-out interlock inoperable.	A.1 Suspend control rod withdrawal.	Immediately
	AND	
	A.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in refuel position.	12 hours
SR 3.9.2.2	- - - - - - - - - - NOTE - - - - - - - - - - Not required to be performed until 1 hour after any control rod is withdrawn. - Perform a CHANNEL FUNCTIONAL TEST.	7 days

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3.9 REFUELING OPERATIONS

3.9.3 Control Rod Position

LCO 3.9.3 All control rods shall be fully inserted.

APPLICABILITY: When loading fuel assemblies into the core.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more control rods not fully inserted.	A.1 Suspend loading fuel assemblies into the core.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify all control rods are fully inserted.	12 hours

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3.9 REFUELING OPERATIONS

3.9.4 Control Rod Position Indication

LCO 3.9.4 One control rod "full-in" position indication channel for each control rod shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

--------------------NOTE--------------------
Separate Condition entry is allowed for each required channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required control rod position indication channels inoperable.	A.1.1 Suspend in-vessel fuel movement. AND	Immediately
	A.1.2 Suspend control rod withdrawal. AND	Immediately
	A.1.3 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. OR	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert the control rod associated with the inoperable position indicator.	Immediately
	<u>AND</u>	
	A.2.2 Initiate action to disarm the associated fully inserted control rod drive.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify the required channel has no "full-in" indication on each control rod that is not "full-in".	Each time the control rod is withdrawn from the "full-in" position

3.9 REFUELING OPERATIONS

3.9.5 Control Rod OPERABILITY - Refueling

LCO 3.9.5 Each withdrawn control rod shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more withdrawn control rods inoperable.	A.1 Initiate action to fully insert inoperable withdrawn control rods.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	----------NOTE--------- Not required to be performed until 7 days after any control rod is withdrawn. --------------------------- Verify each withdrawn control rod will insert at least two notches.	7 days
SR 3.9.5.2	Verify each withdrawn control rod scram accumulator pressure is ≥ 12.75 MPaG (1849 psig).	7 days

STD COL 16.0-1-A
3.9.5-1

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3.9 REFUELING OPERATIONS

3.9.6 Reactor Pressure Vessel (RPV) Water Level

LCO 3.9.6 RPV water level shall be ≥ 7.01 m (23.0 ft) over the top of the RPV flange.

APPLICABILITY: During movement of irradiated fuel assemblies within the RPV, During movement of new fuel assemblies or handling of control rods within the RPV, when irradiated fuel assemblies are seated within the RPV.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RPV water level not within limit.	A.1 Suspend movement of fuel assemblies and handling of control rods within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify RPV water level is ≥ 7.01 m (23.0 ft) above the top of the RPV flange.	24 hours

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3.9 REFUELING OPERATIONS

3.9.7 Decay Time

LCO 3.9.7 The reactor shall be subcritical for at least 24 hours.

APPLICABILITY: During movement of irradiated fuel assemblies within the reactor pressure vessel (RPV).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor not subcritical for at least 24 hours.	A.1 Suspend movement of irradiated fuel assemblies within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify reactor has been subcritical for at least 24 hours.	Prior to movement of irradiated fuel assemblies within the RPV

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3.10 SPECIAL OPERATIONS

3.10.1 Inservice Leak and Hydrostatic Testing Operation

LCO 3.10.1 The average reactor coolant temperature specified in Table 1.1-1 for MODE 5 may be changed to "N/A," and operation considered not to be in MODE 3 or 4 to allow reactor coolant temperature > 93.3°C (200°F):

- For performance of an inservice leak or hydrostatic test;
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test; or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the Reactor Building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas are isolated, or are capable of being isolated on high radiation signals.

APPLICABILITY: MODE 5 with average reactor coolant temperature > 93.3°C (200°F).

ACTIONS

NOTE

Separate Condition entry allowed for each requirement of the LCO.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend activities that could increase the average reactor coolant temperature or pressure.	Immediately
	<u>AND</u>	
	A.2 Reduce average reactor coolant temperature to ≤ 93.3°C (200°F).	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.1.1	----------NOTE--------- Not required to be met if SR 3.10.1.2 satisfied. ---------------------- Verify reactor building REPAVS and CONAVS areas are isolated.	24 hours
SR 3.10.1.2	----------NOTE--------- Not required to be met if SR 3.10.1.1 satisfied. ---------------------- Verify reactor building REPAVS and CONAVS areas are capable of automatic isolation on respective exhaust high radiation signals.	24 hours

3.10 SPECIAL OPERATIONS

3.10.2 Reactor Mode Switch Interlock Testing

LCO 3.10.2 The reactor mode switch position specified in Table 1.1-1 for MODES 3, 4, 5, and 6 operation may be changed to include the run, startup, and refuel position, and operation considered not to be in MODE 1 and 2 to allow testing of instrumentation associated with the reactor mode switch interlock functions, provided:

a. All control rods remain fully inserted in core cells containing one or more fuel assemblies; and

b. No CORE ALTERATIONS are in progress.

APPLICABILITY: MODES 3, 4, and 5 with the reactor mode switch in the run, startup, or refuel position,
MODE 6 with the reactor mode switch in the run or startup position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend CORE ALTERATIONS except for control rod insertion.	Immediately
	<u>AND</u>	
	A.2 Fully insert all insertable control rods in core cells containing one or more fuel assemblies.	1 hour
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Place the reactor mode switch in the shutdown position.	1 hour
	<u>OR</u>	
	A.3.2 ----- NOTE ----- Only applicable in MODE 6. ------------ Place the reactor mode switch in the refuel position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.2.1	Verify all control rods are fully inserted in core cells containing one or more fuel assemblies.	12 hours
SR 3.10.2.2	Verify no CORE ALTERATIONS are in progress.	24 hours

3.10 SPECIAL OPERATIONS

3.10.3 Control Rod Withdrawal – Hot/Stable Shutdown

LCO 3.10.3 The reactor mode switch position specified in Table 1.1-1 for MODES 3 and 4 operation may be changed to include the refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod or control rod pair, provided the following requirements are met:

a. LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock";

b. LCO 3.9.4, "Control Rod Position Indication";

c. All other control rods are fully inserted; and

d. 1. MODE 6 requirements for LCO 3.3.1.1 "Reactor Protection System (RPS) Instrumentation," Functions 1 and 3, of Table 3.3.1.1-1, LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," Functions 1.a and 1.b of Table 3.3.1.4-1, LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," Function 1 of Table 3.3.1.5-1, and LCO 3.9.5, "Control Rod OPERABILITY – Refueling,"

<u>OR</u>

2. All other control rods in a five-by-five array centered on each control rod being withdrawn are disarmed, and LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 6 requirements except the control rod or control rod pair to be withdrawn may be assumed to be the highest worth control rod or control rod pair.

APPLICABILITY: MODES 3 and 4 with the reactor mode switch in the refuel position.

ACTIONS

- - - - - - - - - - - - - - - - - - - NOTE - - - - - - - - - - - - - - - - - - -
Separate Condition entry allowed for each requirement of the LCO.
- -

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 - - - - NOTES - - - - - 1. Required Actions to fully insert all insertable control rods include placing the reactor mode switch in the shutdown position. 2. Only applicable if the requirement not met is a required LCO. - - - - - - - - - - - - Enter the applicable Condition of the affected LCO.	 Immediately
	<u>OR</u>	
	A.2.1 Initiate action to fully insert all insertable control rods.	Immediately
	<u>AND</u>	
	A.2.2 Place the reactor mode switch in the shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.3.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.3.2	- - - - - - - - - - NOTE - - - - - - - - - - Not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements. - Verify all other control rods, other than the control rod(s) being withdrawn, in a five-by-five array centered on each control rod being withdrawn, are disarmed.	24 hours
SR 3.10.3.3	Verify all other control rods, other than the control rod or control rod pair being withdrawn, are fully inserted.	24 hours

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3.10 SPECIAL OPERATIONS

3.10.4 Control Rod Withdrawal – Cold Shutdown

LCO 3.10.4 The reactor mode switch position specified in Table 1.1-1 for MODE 5 may be changed to include refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod or control rod pair, and subsequent removal of the associated control rod drive(s) (CRD) if desired, provided the following requirements are met:

a. All other control rods are fully inserted;

b. 1. LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock," and LCO 3.9.4, "Control Rod Position Indication,"

<u>OR</u>

2. A control rod withdrawal block is inserted; and

c. 1. MODE 6 requirements for LCO 3.3.1.1 "Reactor Protection System (RPS) Instrumentation," Functions 1 and 3 of Table 3.3.1.1-1, LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," Functions 1.a and 1.b of Table 3.3.1.4-1, LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," Function 1 of Table 3.3.1.5-1, and LCO 3.9.5, "Control Rod OPERABILITY – Refueling,"

<u>OR</u>

2. All other control rods in a five-by-five array centered on the control rod being withdrawn are disarmed and LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 6 requirements except the single control rod or control rod pair to be withdrawn may be assumed to be the highest worth control rod or control rod pair.

APPLICABILITY: MODE 5 with the reactor mode switch in the refuel position.

ACTIONS

- - - - - - - - - - - - - - - - - - - NOTE - - - - - - - - - - - - - - - - - - -
Separate Condition entry allowed for each requirement of the LCO.
- -

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met with the affected control rod(s) insertable.	A.1 - - - - NOTES - - - - - 1. Required Actions to fully insert all insertable control rods include placing the reactor mode switch in the shutdown position. 2. Only applicable if the requirement not met is a required LCO. - - - - - - - - - - - -	
	Enter the applicable Condition of the affected LCO.	Immediately
	OR	
	A.2.1 Initiate action to fully insert all insertable control rods.	Immediately
	AND	
	A.2.2 Place the reactor mode switch in the shutdown position.	1 hour

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more of the above requirements are not met with the affected control rod(s) not insertable.	B.1 Suspend withdrawal of the control rod(s) and removal of associated CRD(s).	Immediately
	AND	
	B.2.1 Initiate action to fully insert all control rods.	Immediately
	OR	
	B.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.4.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs
SR 3.10.4.2	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.c.1 requirements. ------------------------------ Verify all control rods, other than the control rod(s) being withdrawn, in a five-by-five array centered on each control rod being withdrawn, are disarmed.	24 hours
SR 3.10.4.3	Verify all other control rods, other than the control rod or control rod pair being withdrawn, are fully inserted.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.4.4	------------NOTE------------ Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.b.1 requirements. ---------------------------- Verify a control rod withdrawal block is inserted.	24 hours

3.10 SPECIAL OPERATIONS

3.10.5 Control Rod Drive (CRD) Removal - Refueling

LCO 3.10.5 The requirements of LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"; LCO 3.3.1.2 "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock"; LCO 3.9.4, "Control Rod Position Indication"; and LCO 3.9.5, "Control Rod OPERABILITY - Refueling," may be suspended during MODE 6 operation to allow the removal of a single CRD or CRD pair associated with control rod(s) withdrawn from core cell(s) containing one or more fuel assemblies, provided the following requirements are met:

a. All other control rods are fully inserted;

b. All other control rods in a five-by-five array centered on the withdrawn control rod(s) are disarmed;

c. A control rod withdrawal block is inserted and LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 6 requirements may be changed to allow the single control rod or control rod pair withdrawn to be assumed to be the highest worth control rod(s); and

d. No CORE ALTERATIONS are in progress.

APPLICABILITY: MODE 6 with LCO 3.9.5 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend removal of the CRD mechanism(s).	Immediately
	AND	
	A.2.1 Initiate action to fully insert all control rods.	Immediately
	OR	
	A.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.5.1	Perform SR 3.1.1.1.	According to SR 3.1.1.1
SR 3.10.5.2	Verify all control rods, other than the control rod(s) withdrawn for the removal of the associated CRD(s), are fully inserted.	24 hours
SR 3.10.5.3	Verify all control rods, other than the control rod or control rod pair withdrawn for the removal of the associated CRD(s), in a five-by-five array centered on each control rod(s) withdrawn for the removal of the associated CRD(s), are disarmed.	24 hours
SR 3.10.5.4	Verify a control rod withdrawal block is inserted.	24 hours
SR 3.10.5.5	Verify no CORE ALTERATIONS are in progress.	24 hours

3.10 SPECIAL OPERATIONS

3.10.6 Multiple Control Rod Withdrawal - Refueling

LCO 3.10.6 The requirements of LCO 3.9.3, "Control Rod Position"; LCO 3.9.4, "Control Rod Position Indication"; and LCO 3.9.5, "Control Rod OPERABILITY - Refueling," may be suspended and the "full-in" position indicators may be bypassed for any number of control rods during MODE 6 operation to allow withdrawal of these control rods, removal of associated control rod drives (CRDs), or both, provided the following requirements are met:

a. The four fuel assemblies are removed from the core cells associated with each control rod or CRD to be removed;

b. All other control rods in core cells containing one or more fuel assemblies are fully inserted; and

c. Fuel assemblies shall only be loaded in compliance with an approved spiral reload sequence.

APPLICABILITY: MODE 6 with LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the above requirements not met.	A.1 Suspend withdrawal of control rods and removal of associated CRDs.	Immediately
	<u>AND</u>	
	A.2 Suspend loading fuel assemblies.	Immediately
	<u>AND</u>	
	A.3.1 Initiate action to fully insert all control rods in core cells containing one or more fuel assemblies.	Immediately
	<u>OR</u>	
	A.3.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.1	Verify the four fuel assemblies are removed from core cells associated with each control rod or CRD removed.	24 hours
SR 3.10.6.2	Verify all other control rods in core cells containing one or more fuel assemblies are fully inserted.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.3	-----NOTE----- Only required to be met during fuel loading. ---------- Verify fuel assemblies being loaded are in compliance with an approved spiral reload sequence.	24 hours

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3.10 SPECIAL OPERATIONS

3.10.7 Control Rod Testing - Operating

LCO 3.10.7 The requirements of LCO 3.1.6, "Rod Pattern Control," may be suspended and control rods bypassed in the Rod Control and Information System (RC&IS) as allowed by SR 3.3.2.1.9, to allow performance of SDM demonstrations, control rod scram time testing, control rod friction testing, and the Startup Test Program, provided conformance to the approved control rod sequence for the specified test is verified by a second licensed operator or other qualified member of the technical staff.

APPLICABILITY: MODES 1 and 2 with LCO 3.1.6 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Suspend performance of the test and exception to LCO 3.1.6.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.7.1	Verify movement of control rods is in compliance with the approved control rod sequence for the specified test, by a second licensed operator or other qualified member of the technical staff.	During control rod movement

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3.10 SPECIAL OPERATIONS

3.10.8 SHUTDOWN MARGIN (SDM) Test - Refueling

LCO 3.10.8 The reactor mode switch position specified in Table 1.1-1 for MODE 6 operation may be changed to include the startup position, and operation considered not to be in MODE 2, to allow SDM testing, provided the following requirements are met:

a. MODE 2 requirements for LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2 of Table 3.3.1.1-1, LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.4 "Neutron Monitoring System (NMS) Instrumentation," Functions 2.a and 2.d of Table 3.3.1.4-1, and LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation, Function 2";

b. 1. LCO 3.3.2.1, "Control Rod Block Instrumentation," MODE 2 requirements for Function 1.b of Table 3.3.2.1-1;

<u>OR</u>

2. Conformance to the approved control rod sequence for the SDM test is verified by a second licensed operator or other qualified member of the technical staff;

c. Each withdrawn control rod shall be coupled to the associated CRD;

d. All control rod withdrawals during out-of-sequence control rod moves shall be made in notch movement mode;

e. No other CORE ALTERATIONS are in progress; and

f. Reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas shall be isolated, or shall be capable of being isolated on high radiation signals.

APPLICABILITY: MODE 6 with the reactor mode switch in startup position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
---- NOTE ------ A. Separate Condition entry is allowed for each control rod. ----------- One or more control rods not coupled to its associated CRD.	----- NOTE ----- Inoperable control rods may be bypassed in accordance with SR 3.3.2.1.9, if required, to allow insertion of inoperable control rod and continued operation. --------------- A.1 Fully insert inoperable control rod. AND A.2 Disarm the associated CRD.	 3 hours 4 hours
B. One or more of the above requirements not met for reasons other than Condition A.	B.1 Place the reactor mode switch in the shutdown or refuel position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.8.1	Perform the MODE 2 applicable SRs for LCO 3.3.1.1 Function 2 of Table 3.3.1.1-1, LCO 3.3.1.2, LCO 3.3.1.4, Functions 2.a and 2.d of Table 3.3.1.4-1, LCO 3.3.1.5, and Function 2 of Table 3.3.1.5-1.	According to the applicable SRs

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.8.2	-----------NOTE----------- Not required to be met if SR 3.10.8.3 satisfied. ------------------------------ Perform the MODE 2 applicable SRs for LCO 3.3.2.1, Function 1.b of Table 3.3.2.1-1.	According to the applicable SRs
SR 3.10.8.3	-----------NOTE----------- Not required to be met if SR 3.10.8.2 satisfied. ------------------------------ Verify movement of control rods is in compliance with the approved control rod sequence for the SDM test by a second licensed operator or other qualified member of the technical staff.	During control rod movement
SR 3.10.8.4	Verify no other CORE ALTERATIONS are in progress.	12 hours
SR 3.10.8.5	-----------NOTE----------- Not required to be met if SR 3.10.8.6 satisfied. ------------------------------ Verify reactor building REPAVS and CONAVS areas are isolated.	24 hours
SR 3.10.8.6	-----------NOTE----------- Not required to be met if SR 3.10.8.5 satisfied. ------------------------------ Verify reactor building REPAVS and CONAVS areas are capable of automatic isolation on respective exhaust high radiation signals.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.8.7	Verify each withdrawn control rod does not go to the withdrawn overtravel position.	Prior to satisfying LCO 3.10.8.c requirement after work on control rod or CRD system could affect coupling

3.10 SPECIAL OPERATIONS

3.10.9 Oxygen Concentration - Startup Test Program

LCO 3.10.9 The requirements of LCO 3.6.1.8, Containment Oxygen Concentration, may be suspended during performance of the Startup Test Program provided ≤ 120 Effective Full Power Days (EFPD) of operation from initial startup of the unit.

APPLICABILITY: THERMAL POWER > 15% RTP with LCO 3.6.1.8 not met.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The above requirement not met.	A.1 Enter the applicable Condition of LCO 3.6.1.8.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.10.9.1 Verify operation ≤ 120 EFPD.	7 days

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3.10 SPECIAL OPERATIONS

3.10.10 Oscillation Power Range Monitor (OPRM) - Initial Cycle

LCO 3.10.10 The requirements for OPERABILITY of the oscillation power range monitor (OPRM) in LCO 3.3.1.1, LCO 3.3.1.4, and LCO 3.3.1.5, may be suspended during the initial cycle of operation provided the alternate method to detect and suppress thermal hydraulic instability oscillations is established.

APPLICABILITY: THERMAL POWER ≥ 25% RTP with OPRM inoperable during initial cycle of operation.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The above requirement not met.	A.1 Reduce THERMAL POWER < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.10.1	Verify on-shift operations staff appropriately trained on alternate method to detect and suppress thermal hydraulic instability oscillations.	92 days

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4.0 DESIGN FEATURES

4.1 Site Location

NAPS COL 16.0-1-A 4.1-1

North Anna Power Station Unit 3 is located on a peninsula on the southern shore of Lake Anna in the north-central portion of Virginia in Louisa County. The site is about 40 miles north-northwest of Richmond, Virginia; 36 miles east of Charlottesville, Virginia; and 22 miles southwest of Fredericksburg, Virginia.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 1132 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy clad fuel rods with an initial composition of slightly enriched uranium dioxide (UO_2) as fuel material, and water rods. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 269 cruciform-shaped control rod assemblies. The control material shall be boron carbide or a combination of boron carbide and hafnium metal, as approved by the NRC.

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks in the Fuel Building spent fuel storage pool and in the Reactor Building buffer pool deep pit are designed and shall be maintained with:

a. Fuel assemblies having a maximum lattice k-infinity of 1.32 in the normal reactor core configuration at cold conditions;

4.0 DESIGN FEATURES

4.3.1.1 (continued)

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties and biases as described in Section 9.1 of the Final Safety Analysis Report; and

c. A nominal fuel assembly center-to-center storage spacing of 168 mm (6.61 inches), with a neutron poison material between storage spaces, in the high density storage racks in the Fuel Building spent fuel storage pool and in the Reactor Building buffer pool deep pit.

4.3.1.2 The new fuel storage racks in the Reactor Building buffer pool are designed and shall be maintained with:

a. Fuel assemblies having a maximum lattice k-infinity of 1.32 in the normal reactor core configuration at cold conditions; and

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties and biases as described in Section 9.1 of the Final Safety Analysis Report.

c. A nominal center-to-center storage spacing of 251 mm (9.88 inches) for fuel assemblies placed in the same row of a storage rack; a nominal center-to-center storage spacing of 244 mm (9.61 inches) for fuel assemblies placed in adjacent rows of a storage rack.

4.3.2 Drainage

4.3.2.1 The Fuel Building spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below an elevation of 14.3 m (46.9 ft) above the floor of the pool.

4.3.2.2 The Reactor Building buffer pool deep pit is designed and shall be maintained to prevent inadvertent draining of the pool below an elevation of 16.2 m (53.1 ft) above the floor of the deep pit area.

4.0 DESIGN FEATURES

4.3.3 Capacity

4.3.3.1 The Fuel Building spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 3504 fuel assemblies.

4.3.3.2 The Reactor Building buffer pool deep pit is designed and shall be maintained with a storage capacity limited to no more than 154 fuel assemblies.

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5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

NOTE

Organizational positions listed or described in the Administrative Controls Section shall have corresponding plant-specific staff titles specified in the Final Safety Analysis Report.

5.1.1 The plant manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The plant manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The Shift Supervisor (SS) shall be responsible for the control room command function. During any absence of the SS from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SS from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

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5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the FSAR;

b. The plant manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

STD COL 16.0-1-A 5.2.2-1 a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned for each control room from which a reactor is operating in MODE 1, 2, 3, or 4.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.e for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. The operations manager or assistant operations manager shall hold an SRO license.

e. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 3, 2000. Exceptions to Regulatory Guide 1.8, Revision 3 are specified in the Quality Assurance Program Description. Cold license operator candidates meet the equivalent requirements in the Nuclear Energy Institute Topical Report NEI-06-13A, Revision 2, "Template for an Industry Training Program Description."

NAPS COL 16.0-1-A 5.3.1-1

5.3.2 For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed Reactor Operator (RO) are those individuals who, in addition to meeting the requirements of Specification 5.3.1, perform the functions described in 10 CFR 50.54(m).

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5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

STD COL 16.0-1-A 5.4.1-1

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

STD COL 16.0-1-A 5.4.1-2

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and to NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

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5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 <u>Offsite Dose Calculation Manual (ODCM)</u>

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Reports required by Specification 5.6.1 and Specification 5.6.2.

c. Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   i. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   ii. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

2. Shall become effective after approval of the plant manager; and

3. Shall be submitted to the NRC in the form of a complete, legible copy of the changed portion of the ODCM as a part of, or concurrent with, the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include the Isolation Condenser System, Fuel and Auxiliary Pools Cooling System, Containment Monitoring System, and Reactor Water Cleanup/Shutdown Cooling System. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at least once per 24 months.

The provisions of SR 3.0.2 are applicable.

5.5.3 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001-20.2402;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

5.5 Programs and Manuals

5.5.3 Radioactive Effluent Controls Program (continued)

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

   1. For noble gases: a dose rate ≤ 5 mSv/yr (500 mrem/yr) to the whole body and a dose rate ≤ 30 mSv/yr (3000 mrem/yr) to the skin, and

   2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: a dose rate ≤ 15 mSv/yr (1500 mrem/yr) to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to release of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

5.5 Programs and Manuals

5.5.4 Component Cyclic or Transient Limit

This program provides controls to track the FSAR Table 3.9-1 cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.5 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code):

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and to other normal and accelerated Frequencies specified as 2 years or less in the Inservice Testing Program for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.5 Programs and Manuals

5.5.6 Explosive Gas and Radioactivity Monitoring Program

STD COL 16.0-1-A 5.5.6-1

This program provides controls for potentially explosive gas mixtures contained in the offgas treatment system and for the quantity of radioactivity fed into the offgas treatment system. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) 11-5, "Postulated Radioactive Releases Due to Waste Gas System Leak or Failure."

STD COL 16.0-1-A 5.5.6-1

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the offgas treatment system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity fed into the offgas treatment system is less than the amount that would result in a whole body exposure of ≥ 5 mSv (0.5 rem) to any individual in an unrestricted area, in the event of an uncontrolled release.

STD COL 16.0-1-A 5.5.6-1

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Radioactivity Monitoring Program surveillance frequencies.

5.5.7 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license, or

   2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

5.5 Programs and Manuals

5.5.7 Technical Specifications (TS) Bases Control Program (continued)

d. Proposed changes that meet the criteria of 5.5.7.b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.8 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross-division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, or no concurrent loss of onsite safety-related power, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable;

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

5.5 Programs and Manuals

5.5.8 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.9 Containment Leakage Rate Testing Program

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exceptions:

   1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, shall be performed in accordance with the requirements of and frequency specified by ASME Code Section XI, Subsection IWL, except where relief has been authorized by the NRC. The containment concrete visual examinations may be performed during either power operation or during a maintenance/refueling outage.

   2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing shall be performed in accordance with the requirements of and frequency specified by ASME Code Section XI, Subsection IWE, except where relief has been authorized by the NRC.

STD COL 16.0-1-A 5.5.9-1

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 310 kPaG (45 psig). The containment design pressure is 310 kPaG (45 psig).

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.35% of containment air weight per day.

d. Leakage rate acceptance criteria are:

   1. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$ for leakage from Containment. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests.

5.5 Programs and Manuals

5.5.9 Containment Leakage Rate Testing Program (continued)

2. Air lock testing acceptance criteria are:

   a. Overall air lock leakage rate is ≤ 0.05 L_a when tested at ≥ P_a.

   b. For each door, leakage rate is ≤ 0.01 L_a when pressurized to ≥ 10 psig.

3. Passive Containment Cooling System (PCCS) leakage rate acceptance criterion is ≤ 0.01% of containment air weight per day.

e. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

f. Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10 CFR 50, Appendix J.

5.5.10 Battery Monitoring and Maintenance Program

This Program provides for battery restoration and maintenance, which includes the following:

STD COL 16.0-1-A 5.5.10-1

a. With battery cell float voltage < 2.13 V, actions to restore cell(s) to ≥ 2.13 V and perform SR 3.8.3.5,

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the minimum established design limit;

c. Limits on average electrolyte temperature, battery connection resistance, and battery terminal voltage; and

d. A requirement to obtain specific gravity readings of all cells at each discharge test, consistent with manufacturer recommendations.

5.5.11 Setpoint Control Program (SCP)

a. The Setpoint Control Program (SCP) implements the regulatory requirement of 10 CFR 50.36(c)(1)(ii)(A) that technical specifications will include items in the category of limiting safety system settings (LSSS), which are settings for automatic protective devices related to those variables having significant safety functions.

b. The Limiting Trip Setpoint (LTSP), Nominal Trip Setpoint ($NTSP_F$), Allowable Value (AV), As-Found Tolerance (AFT), and As-Left Tolerance (ALT) for each Technical Specification required automatic

5.5 Programs and Manuals

5.5.11 Setpoint Control Program (SCP) (continued)

STD COL 16.0-1-A 5.5.11-1

protection instrumentation function shall be calculated in conformance with the instrumentation setpoint methodology previously reviewed and approved by the NRC in NEDE-33304P-A, "GEH ESBWR Setpoint Methodology," Revision 4, dated May 2010, (Public Version ML101450251), and the conditions stated in the associated NRC safety evaluation, Letter to GEH from NRC, "Final Safety Evaluation Report for the Economic Simplified Boiling Water Reactor Design," Dated March 9, 2011, (ML110050215, specifically Chapter 7 FSER ML110030049 and Chapter 16 FSER ML110030064).

c. For each Technical Specification required automatic protection instrumentation function, performance of a CHANNEL CALIBRATION surveillance shall include the following:

1. The as-found value of the instrument channel trip setting shall be compared with the previous as-left value or the specified $NTSP_F$.

   i. If the as-found value of the instrument channel trip setting differs from the previous as-left value or the specified $NTSP_F$ by more than the pre-defined test acceptance criteria band (i.e., the specified AFT), then the instrument channel shall be evaluated to verify that it is functioning in accordance with its design basis before declaring the surveillance requirement met and returning the instrument channel to service. This condition shall be dispositioned by the plant's corrective action program.

   ii. If the as-found value of the instrument channel trip setting is less conservative than the specified AV the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

2. The instrument channel trip setting shall be set to a value within the specified ALT around the specified $NTSP_F$ at the completion of the surveillance; otherwise, the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

d. The difference between the instrument channel trip setting as-found value and either the previous as-left value or the specified $NTSP_F$, for each Technical Specification required automatic protection instrumentation function shall be trended and evaluated to verify that the instrument channel is functioning in accordance with its design basis.

5.5 Programs and Manuals

5.5.11 Setpoint Control Program (SCP) (continued)

e. The SCP shall establish a document containing the current value of the specified LTSP, $NTSP_F$, AV, AFT, and ALT for each Technical Specification required automatic protection instrumentation function and references to the calculation documentation. Changes to this document shall be governed by the regulatory requirements of 10 CFR 50.59. In addition, changes to the specified LTSP, $NTSP_F$, AV, AFT, and ALT values shall be governed by the approved setpoint methodology. This document, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.5.12 Control Room Habitability Area (CRHA) Boundary Program

STD COL 16.0-1-A 5.5.12-1

A CRHA Boundary Program shall be established and implemented to ensure that CRHA habitability is maintained such that, with an OPERABLE CRHA Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS), CRHA occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRHA under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRHA and the CRHA boundary.

b. Requirements for maintaining the CRHA boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRHA boundary into the CRHA in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRHA habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRHA pressure relative to all external areas adjacent to the CRHA boundary during the pressurization mode of operation by one train of the CRHAVS, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 24 month assessment of the CRHA boundary.

5.5 Programs and Manuals

5.5.12 Control Room Habitability Area (CRHA) Boundary Program (continued)

e. The quantitative limits on unfiltered air inleakage into the CRHA. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences less the amount designated for ingress and egress.

NAPS COL 16.0-1-A
5.5.12-1

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRHA habitability, determining CRHA unfiltered inleakage, and measuring CRHA pressure and assessing the CRHA boundary as required by paragraphs c and d, respectively.

5.5.13 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 3, and in accordance with Regulatory Guide 1.52, Revision 3 and ASME AG-1-2003.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 3 and ASME AG-1-2003 at the system flowrate specified below ± 10%:

ESF Ventilation System	Flowrate
Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Emergency Filter Unit (EFU)	220 l/s (466 cfm)

b. Demonstrate for each of the ESF systems that an inplace test of the carbon adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 3 and ASME AG-1-2003 at the system flowrate specified below ± 10%:

ESF Ventilation System	Flowrate
CRHAVS EFU	220 l/s (466 cfm)

5.5 Programs and Manuals

5.5.13 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the carbon adsorber, when obtained as described in Regulatory Guide 1.52, Revision 3, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and the relative humidity specified below:

ESF Ventilation System	Penetration	RH
CRHAVS EFU	0.5%	95%

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the carbon adsorbers is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 3 and ASME AG-1-2003 at the system flowrate specified below ± 10%:

ESF Ventilation System	Delta P	Flowrate
CRHAVS EFU	500 Pa (2.0" w.g.)	220 l/s (466 cfm)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.14 Post-Accident Monitoring (PAM) Instrumentation Program

This program provides controls to establish accident monitoring instrumentation functions that are required by Specification 3.3.3.2, "Post-Accident Monitoring (PAM) Instrumentation." These instrumentation functions shall be those designated as Type A, B, and C, as defined in Regulatory Guide (RG) 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," Revision 4, June 2006, and shall be listed in the PAM function list document as described in Section 7.5.1. Changes to the list of Type A, B, and C functions shall be made in accordance with the provisions of 10 CFR 50.59 and RG 1.97, Revision 4.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Annual Radiological Environmental Operating Report

NOTE

NAPS COL 16.0-1-A 5.6.1-1

A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

STD COL 16.0-1-A 5.6.1-2

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.2 Radioactive Effluent Release Report

NOTE

NAPS COL 16.0-1-A 5.6.2-1

A single submittal may be made for a multiple unit station. The submittal shall combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit during the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be

5.6 Reporting Requirements

5.6.2 Radioactive Effluent Release Report (continued)

consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.3 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Specification 3.2.1, "LINEAR HEAT GENERATION RATE (LHGR)"

2. Specification 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"

3. Specification 3.3.1.1, Reactor Protection System (RPS) Instrumentation," Functions 14, 15, and 16

4. Specification 3.3.1.4, Neutron Monitoring System (NMS) Instrumentation, Function 3

STD COL 16.0-1-A 5.6.3-1

5. Specification 3.7.6, "Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions"

STD COL 16.0-1-A 5.6.3-2

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. MFN-036-85, C. O. Thomas (NRC) to J. S. Charnley (GE), Acceptance for Referencing of Licensing Topical Report NEDE-24011-P Amendment 7 to Revision 6, GE Standard Application for Reactor Fuel, March 1, 1985.

2. MFN-170-84, J. S. Charnley (GE) to R. Lobel (NRC), Fuel Property and Performance Model Revisions (Special Report MFN-170-84-0), December 14, 1984.

3. MFN-027-86, J. S. Charnley (GE) to G. C. Lainas (NRC), Special Report MFN-170-84-1 (Revision 1 to MFN-170-84-0), Fuel Property and Performance Model Revisions, April 7, 1986.

4. MFN-056-87, J. S. Charnley (GE) to M. W. Hodges (NRC), Revision 2 to Special Report MFN-170-84, Fuel Property and Performance Model Revisions, July 23, 1987.

5.6 Reporting Requirements

5.6.3 CORE OPERATING LIMITS REPORT (COLR) (continued)

5. MFN-037-98, G. A. Watford (GE) to J. H. Wilson (NRC), Completion of Program to Confirm Elevated Concentration Gadolinia Fuel Performance Prediction Capability, September 8, 1998.

6. MFN-031-99, G. A. Watford (GE) to S. Dembek (NRC), Fuel Property and Performance Model Revisions, August 20, 1999.

7. NEDE-33083 Supplement 3P-A, "TRACG Application for ESBWR Transient Analysis," Revision 1, September 2010.

8. NEDO-33338, "ESBWR Feedwater Temperature Operating Domain Transient and Accident Analysis," Revision 1, May 2009.

9. Chapter 4, "Reactor," Appendix 4D, "Stability Evaluation," Section 4D.3.2.2.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.4 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

STD COL 16.0-1-A 5.6.4-1

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

LCO 3.4.4, "RCS Pressure and Temperature (P/T) Limits."

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NEDC-33441P, "GE Hitachi Nuclear Energy Methodology for the Development of ESBWR Reactor Pressure Vessel Pressure-Temperature Curves," Revision 6, November 2013.

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6 Reporting Requirements

5.6.5 Post-Accident Monitoring Report

When a Special Report is required by Condition B or C of LCO 3.3.3.2, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 10 mSv (1.0 rem)/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area, or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 10 mSv (1.0 rem)/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

    i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

    ii. Be under the surveillance, as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 High Radiation Areas with Dose Rates Greater than 10 mSv (1.0 rem)/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 5 grays (500 rads)/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

    1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designee.

    2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 10 mSv (1.0 rem)/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 5 grays (500 rads)/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess one of the following:

   1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

   2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

   3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

      i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

      ii. Be under the surveillance, as specified in the RWP or equivalent, while in the area, by means of closed circuit television, or personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 10 mSv (1.0 rem)/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 5 grays (500 rads)/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. The dose rate determination, knowledge, and pre-job briefing do not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

TECHNICAL SPECIFICATIONS BASES

FOR NORTH ANNA UNIT 3

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3.3 Instrumentation (continued)

B 3.7 Plant Systems (continued)

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B 2.0 SAFETY LIMITS (SLS)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

Because fuel damage is not directly observable, a stepback approach is used to establish the SL specified in Specification 2.1.1.2. The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. These conditions represent a significant departure from the condition intended by design for planned operation. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. To ensure damage does not occur, the Fuel Cladding Integrity Safety Limit (FCISL) is established as greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the FCISL limit. The Safety Limit MCPR (SLMCPR) is a lower bound on the steady-state MCPR that ensures greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition.

2.1.1.1 Fuel Cladding Integrity

GE14 critical power correlations are applicable for all critical power calculations at pressures > 4.72 MPa (685 psig) (Ref. 2). However, for operation at low pressures, and low-power operation at higher pressures up to 25% RTP at rated pressure, such as may be seen during startup or shutdown, another basis applies: The full scale thermal hydraulic testing of prototypical ESBWR fuel assemblies at low pressure was performed at very low flows and over a range of inlet temperatures and pressures representative of startup conditions and the onset of Boiling Transition observed. The critical bundle powers at which the onset of Boiling Transition occurred in these experiments was a factor of 3, or more, higher than achievable bundle powers in reactor during low pressure, low power operation even when very conservative assumptions on reactor conditions are made. Adequate heat transfer is assured during low pressure and low power operation, including startup and operation up to 25% RTP at rated pressure.

2.1.1.2 FCISL and SLMCPR

The FCISL is set such that no significant fuel damage is calculated to occur for AOOs. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, a calculated fraction of rods expected to avoid boiling transition has been adopted as a convenient limit. The steady-state and transient uncertainties and the uncertainties in monitoring and simulating the core operating state are incorporated by the statistical model

BASES

APPLICABLE SAFETY ANALYSES (continued)

that calculates the fraction of rods. Therefore, an operating limit MCPR is defined such that the FCISL is not violated during normal operations and AOOs, considering the power distribution within the core and all uncertainties.

The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the FCISL calculation process are given in References 2, 3, 4, and 5. Reference 2 also describes the methodology for determining the transient uncertainties and the process for calculating the operating limit MCPR, and the steady state uncertainties used in the statistical analysis.

The Safety Limit MCPR (SLMCPR) is a lower bound on the steady-state MCPR. Details of the SLMCPR calculation process are given in Reference 2.

2.1.1.3 Reactor Vessel Water Level

During MODES 1 and 2, the reactor vessel water level is required to be above the top of the active fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level drops below the top of the active irradiated fuel. The reactor vessel water level SL has been established at the top of the active irradiated fuel to provide a point that can be monitored.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

BASES

APPLICABILITY	SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.
SAFETY LIMIT VIOLATIONS	Exceeding a SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 52.47(a)(2)(iv) (Ref. 6). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and the probability of an accident occurring during this period is minimal.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. NEDC-33237P-A, GE14 for ESBWR - Critical Power Correlation, Uncertainty, and OLMCPR Development, Revision 5, September 2010.
3. NEDE-10958-PA, General Electric Thermal Analysis Basis Data, Correlation and Design Application, January 1977.
4. NEDC-33083P-A, TRACG Application for ESBWR, Revision 1, September 2010.
5. NEDC-32601P-A, Methodology and Uncertainties for Safety Limit MCPR Evaluations, August 1999.
6. 10 CFR 52.47(a)(2)(iv).

B 2.0 SAFETY LIMITS (SLS)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on reactor vessel bottom pressure protects the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. Establishing an upper limit on reactor vessel bottom pressure ensures continued RCS integrity. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) shall be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation and anticipated operational occurrences (AOOs).

During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB, reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 52.47(a)(2)(iv) (Ref. 4). If this occurred in conjunction with a fuel cladding failure, the number of protective barriers designed to prevent radioactive releases from exceeding the limits would be reduced.

APPLICABLE SAFETY ANALYSES

The RCS safety relief valves and the Reactor Protection System Scram settings are established to ensure that the RCS pressure SL will not be exceeded.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to ASME, Boiler and Pressure Vessel Code, Section III, 2001 Edition, including Addenda through 2003 (Ref. 5), which permits a maximum pressure transient of 110% of the design pressure of 8.618 MPaG (1250 psig). Therefore, the SL is 9.481 MPaG (1375 psig) at the lowest elevation of the RCS. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.
SAFETY LIMITS	The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 110% of design pressures of 8.618 MPaG (1250 psig). The most limiting of these allowances is the 110% of the RCS design pressure; therefore, the SL on maximum allowable RCS pressure is established at 9.481 MPaG (1375 psig) at the lowest elevation of the RCS.
APPLICABILITY	SL 2.1.2 applies in all MODES.
SAFETY LIMIT VIOLATIONS	Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 52.47(a)(2)(iv) (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14 and GDC 15.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IW-5000.
4. 10 CFR 52.47(a)(2)(iv).
5. ASME, Boiler and Pressure Vessel Code, 2001 Edition, Addenda, 2003.

B 3.0 LIMITING CONDITIONS FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.7 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified Conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

BASES

LCO 3.0.2 (continued)

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.4, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions/trains of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

BASES

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, "Completion Times."

BASES

LCO 3.0.3 (continued)

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met;

b. A Condition exists for which the Required Actions have now been performed; or

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 2 is reached in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for reaching MODE 3 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.5, "Fuel Pool Water Level and Temperature." LCO 3.7.5 has an Applicability of "During movement of irradiated fuel assemblies in the associated fuel storage

BASES

LCO 3.0.3 (continued)

pool" and "When irradiated fuel assemblies are stored in the associated fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.5 are not met while in MODE 1, 2, 3, or 4, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Actions of LCO 3.7.5 of "Suspend movement of irradiated fuel assemblies in the associated fuel storage pool(s)" and "Initiate action to restore water level and temperature to within limit" are the appropriate Required Actions to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires

BASES

LCO 3.0.4 (continued)

that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, if a subset of systems and components are determined to be more important to risk, then

LCO 3.0.4 (continued)

use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components will contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant System Specific Activity), and may be applied to other Specifications based on NRC plant specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified

BASES

LCO 3.0.4 (continued)

limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowances for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

BASES

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.8, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and

BASES

LCO 3.0.6 (continued)

Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division/train checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division/train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained.

If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately address the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified,

BASES

LCO 3.0.7 (continued)

all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO ACTIONS may direct the other LCOs' ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

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B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs

BASES

SR 3.0.1 (continued)

whose performance is normally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed. An example of this process is Control Rod Drive maintenance during refueling that requires scram testing at reactor steam dome pressure ≥ 6.55 MPaG (950 psig). However, if other appropriate testing is satisfactorily completed and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach reactor steam dome pressure of 6.55 MPaG (950 psig) to perform other necessary testing.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Primary Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

SR 3.0.3 (continued)

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities

BASES

SR 3.0.3 (continued)

at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

BASES

SR 3.0.4 (continued)

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to a Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, train, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment.

When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or

BASES

SR 3.0.4 (continued)

other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, "Frequency."

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

SDM requirements are specified to ensure:

a. The reactor can be made subcritical from all operating conditions, transients, and design basis events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits; and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

These requirements are satisfied by the control rods, as described in GDC 26 (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE SAFETY ANALYSES

SDM is an explicit assumption in several of the evaluations in Chapter 15, Safety Analyses. SDM is assumed as an initial condition for the control rod removal error during refueling accident (Ref. 2). The analysis of these reactivity insertion events assumes the refueling interlocks are OPERABLE when the reactor is in the refueling mode of operation. These interlocks prevent the withdrawal of more than one control rod, or control rod pair, from the core during refueling. (Special consideration and requirements for multiple control rod withdrawal during refueling are covered in Special Operations LCO 3.10.6, "Multiple Control Rod Withdrawal - Refueling.") The analysis assumes this condition is acceptable since the core will be shutdown with the highest worth control rod or rod pair withdrawn, if adequate SDM has been demonstrated.

Prevention or mitigation of reactivity insertion events is necessary to limit energy deposition in the fuel to prevent significant fuel damage, which could result in undue release of radioactivity (see Bases for LCO 3.1.6, "Rod Pattern Control"). Adequate SDM ensures inadvertent criticalities will not cause significant fuel damage.

BASES

APPLICABLE SAFETY ANALYSES (continued)

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specified SDM limit accounts for the uncertainty in the demonstration of SDM by testing. Separate SDM limits are provided for testing where the highest worth control rod or rod pair is determined analytically or by measurement. This is due to the reduced uncertainty in the SDM test when the highest worth control rod or rod pair is determined by measurement. When SDM is demonstrated by calculations not associated with a test (e.g., to confirm SDM during the fuel loading sequence), additional margin must be added to the specified SDM limit to account for uncertainties in the calculation. To assure adequate SDM, a design margin is included to account for uncertainties in the design calculations (Ref. 3).

APPLICABILITY

In MODES 1 and 2, SDM must be provided because subcriticality with the highest worth control rod or rod pair withdrawn is assumed in the analysis. In MODES 3, 4, and 5, SDM is required to ensure the reactor will be held subcritical with margin for a single withdrawn control rod or rod pair. SDM is required in MODE 6 to prevent an inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies or of a control rod pair from loaded core cells during scram time testing.

ACTIONS

A.1

With SDM not within the limits of the LCO in MODE 1 or 2, SDM must be restored within 6 hours. Failure to meet the specified SDM may be caused by a control rod that cannot be inserted. The 6-hour Completion Time is acceptable considering that the reactor can still be shut down assuming no additional failures of control rods to insert, and the low probability of an event occurring during this interval.

B.1

If the SDM cannot be restored, the reactor must be in MODE 3 within 12 hours to prevent the potential for further reductions in available SDM (e.g., additional stuck control rods). The allowed Completion Time of 12 hours is

BASES

ACTIONS (continued)

reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

C.1

With SDM not within limits in MODE 3 or 4, the operator must immediately initiate action to fully insert all insertable control rods. This action results in the least reactive condition for the core.

D.1 and D.2

With SDM not within limits in MODE 5, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core. Action must also be initiated immediately to establish reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) area isolation boundary. This can be accomplished by isolating the REPAVS and CONAVS dampers or verifying the automatic capability of the respective exhaust high radiation function.

E.1, E.2, and E.3

With SDM not within limits in MODE 6, the operator must immediately suspend CORE ALTERATIONS that could reduce SDM (e.g., insertion of fuel in the core or withdrawal of control rods). Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Inserting control rods or removing fuel from the core will reduce the total reactivity and are therefore excluded from the suspended actions.

Action must also be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies have been fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore do not have to be inserted.

BASES

ACTIONS (continued)

Action must also be initiated immediately to establish reactor building REPAVS and CONAVS area isolation boundary. This can be accomplished by isolating the REPAVS and CONAVS dampers or verifying the automatic capability of the respective exhaust high radiation function.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

Adequate SDM is verified to ensure the reactor can be made subcritical from any initial operating condition. Adequate SDM must be demonstrated by testing before or during the first startup after fuel movement, shuffling within the reactor pressure vessel, or control rod replacement. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value of core reactivity must be increased by an adder, R, which is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated BOC core reactivity. If the value of R is negative (that is, BOC is the most reactive point in the cycle), no correction to the BOC measured value is required (Ref. 4). For the SDM demonstrations that rely solely on calculation of the highest worth control rod, additional margin (0.10% $\Delta k/k$) must be added to the SDM limit to account for uncertainties in the calculation.

The SDM may be demonstrated during an in-sequence control rod withdrawal, in which the highest worth control rod pair is analytically determined, or during local criticals, where the highest worth control rod pair is determined by testing. Local critical tests require the withdrawal of out of sequence control rods. This testing could therefore require bypassing of the Rod Pattern Control System to allow the out of sequence withdrawal, so additional requirements must be met (see LCO 3.10.7, "Control Rod Testing - Operating").

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable time to perform the required calculations and appropriate verification.

BASES

SURVEILLANCE REQUIREMENTS (continued)

During MODE 6, adequate SDM is also required to ensure the reactor does not reach criticality during control rod withdrawals. An evaluation of each in-vessel fuel movement during fuel loading (including shuffling fuel within the core) shall be performed to ensure adequate SDM is maintained during refueling. This ensures the intermediate loading patterns are bounded by the safety analyses for the final core loading pattern. For example, bounding analyses, which demonstrate adequate SDM for the most reactive configurations during the refueling, may be performed to demonstrate acceptability of the entire fuel movement sequence. For these SDM demonstrations, which rely solely on calculation, additional margin must be added to the specified SDM limit to account for uncertainties in the calculation. Spiral off-load or reload sequences inherently satisfy the SR provided the fuel assemblies are reloaded in the same configuration analyzed for the new cycle. Removing fuel from the core will always result in an increase in SDM.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. Section 15.3.7.
3. NEDC-33239P-A, GE14 for ESBWR Nuclear Design Report, Revision 5, October 2010.
4. Section 4.3.3.3.1.

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable such that subcriticality is maintained under cold conditions and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Reactivity anomaly is used as a measure of the predicted versus measured core reactivity during power operation. The continual confirmation of core reactivity is necessary to ensure that safety analyses of design basis transients and accidents remain valid. A large reactivity anomaly could be the result of unanticipated changes in fuel reactivity, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers, producing zero net reactivity.

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel loaded in the previous cycles provide excess positive reactivity beyond that required to sustain steady state operation at the beginning of cycle (BOC). When the reactor is critical at RTP and operating moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel.

BASES

BACKGROUND (continued)	The predicted core reactivity, as represented by k-effective (k_{eff}), is calculated by a 3D core simulator code as a function of cycle exposure. This calculation is performed for projected operating states and conditions throughout the cycle. The monitored k_{eff} is calculated by the core monitoring system for actual plant conditions and is then compared to the predicted value for the cycle exposure.
APPLICABLE SAFETY ANALYSES	Accurate prediction of core reactivity is either an explicit or implicit assumption in many of the safety analyses in Chapter 15 (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal error events are very sensitive to accurate prediction of core reactivity. These analyses rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity. The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted k_{eff} for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict k_{eff} may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the measured k_{eff} from the predicted k_{eff} that develop during fuel depletion may be an indication that the assumptions of the design basis transient and accident analyses are no longer valid, or that an unexpected change in core conditions has occurred. Reactivity Anomalies satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The reactivity anomaly limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. Large differences between monitored and predicted core reactivity may indicate that the assumptions of the design basis transient and accident analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the difference between the monitored core k_{eff} and the predicted

BASES

LCO (continued)

core k_{eff} of ± 1% Δk/k has been established based on engineering judgment. A > 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

APPLICABILITY

In MODE 1, most of the control rods are withdrawn and steady-state operation is typically achieved. Under these conditions, the comparison between predicted and monitored core reactivity provides an effective measure of the reactivity anomaly. In MODE 2, control rods are typically being withdrawn during a startup. In MODES 3, 4 and 5, all control rods are fully inserted, and, therefore, the reactor is in the least reactive state where monitoring core reactivity is not necessary. In MODE 6, fuel loading results in a continually changing core reactivity. SDM requirements (LCO 3.1.1) ensure that fuel movements are performed within the bounds of the safety analyses, and a SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling). The SDM test, required by LCO 3.1.1, provides a direct comparison of the predicted and monitored core reactivity at cold conditions, and, therefore, reactivity anomaly is not required during these conditions.

ACTIONS

A.1

Should an anomaly develop between measured and predicted core reactivity, the core reactivity difference must be restored within the limit to ensure continued operation is within the core design assumptions. Restoration to within the limit could be performed by an evaluation of the core design and safety analysis to determine the reason for the anomaly. This evaluation normally reviews the core conditions to determine their consistency with input to design calculations. Measured core and process parameters are also normally evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models may be reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is acceptable based on the low probability of a Design Basis Accident occurring during this interval and allows sufficient time to assess the physical condition of the reactor and to complete an evaluation of the core design and safety analysis.

BASES

ACTIONS (continued)

B.1

The unit must be placed in a MODE in which the LCO does not apply if the core reactivity cannot be restored to within the 1% Δk/k limit. This is done by placing the unit in at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Verifying the reactivity difference between the monitored and predicted core k_{eff} is within the limits of the LCO provides added assurance that plant operation is maintained within the assumptions of the design basis transient and accident analyses. The core monitoring system calculates the core k_{eff} for the reactor conditions obtained from plant instrumentation. A comparison of the monitored core k_{eff} to the predicted core k_{eff} at the same cycle exposure is used to calculate the reactivity difference. The comparison is required when the core reactivity has potentially changed by a significant amount. This may occur following a refueling in which new fuel assemblies are loaded, fuel assemblies are shuffled within the core, or control rods are replaced or shuffled. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Also, core reactivity changes during the cycle. The 24 hour interval after reaching equilibrium conditions following a startup was established based on the need for equilibrium xenon concentrations in the core such that an accurate comparison between the monitored and predicted core k_{eff} values can be made. For the purposes of this SR, the reactor is assumed to be at equilibrium conditions when steady state operations (no control rod movement) at ≥ 75% RTP have been obtained. The 1000 MWD/T Frequency was developed considering the relatively slow change in core reactivity with exposure and operating experience related to variations in core reactivity. This comparison requires the core to be operating at power levels which minimize the uncertainties and measurement errors, in order to obtain meaningful results. Therefore, the comparison is only done when in MODE 1.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.

2. Chapter 15.

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Control Rod OPERABILITY

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, which is the primary Reactivity Control System for the reactor. In conjunction with the Reactor Protection System (RPS), the CRD System provides the means for the reliable control of reactivity changes to ensure that under conditions of normal operation, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded. In addition, the control rods provide the capability to hold the reactor core subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. The CRD System is designed to satisfy the requirements of GDC 26, GDC 27, GDC 28, and GDC 29 (Ref. 1).

The CRD System consists of 269 fine motion control rod drive (FMCRD) mechanisms and 135 hydraulic control unit (HCU) assemblies. The FMCRD is an electro-hydraulic actuated mechanism that provides normal positioning of the control rods using an electric motor, and scram insertion of the control rods using hydraulic power. The hydraulic power for scram is provided by high pressure water stored in the individual HCU accumulators, each of which supplies sufficient volume to scram two FMCRDs. Normal control rod positioning is performed using a ball-nut and rotating ballscrew arrangement driven by an electric motor. A hollow piston, which is coupled at the upper end to the control rod, rests on the ball-nut. The ball-nut inserts the hollow piston and connected control rod into the core or withdraws them depending on the direction of rotation of the motor. An electromechanical brake mechanism engages the motor drive shaft when the motor is deenergized to prevent inadvertent withdrawal of the control rod, but does not restrict scram insertion.

This Specification along with LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators," ensures that the performance of the control rods in the event of a Design Basis Accident (DBA) or transient meets the assumptions used in the safety analyses of References 2, 3, 4, 5 and 6.

BASES

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in the evaluations involving control rods are presented in References 2, 3, 4, 5, and 6. The control rods provide the primary means for rapid reactivity control (reactor scram), for maintaining the reactor subcritical, and for limiting the potential effects of reactivity insertion events caused by malfunctions in the CRD System.

The capability to insert the control rods ensures that the assumptions for scram reactivity in the design basis transient and accident analyses are not violated. Since the SDM ensures the reactor will be subcritical with the highest worth control rod or control rod pair withdrawn (assumed single failure of an hydraulic control unit (HCU)), the failure of an additional control rod or control rod pair to insert, if required, could invalidate the demonstrated SDM and potentially limit the ability of the CRD System to hold the reactor subcritical. Therefore, the requirement that all control rods be OPERABLE ensures the CRD System can perform its intended function.

The control rods also protect the fuel from damage that could result in release of radioactivity. The limits protected are the Fuel Cladding Integrity Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "LINEAR HEAT GENERATION RATE (LHGR)"), and the fuel damage limit (see Bases for LCO 3.1.6, "Rod Pattern Control") during reactivity insertion events.

The negative reactivity insertion (scram) provided by the CRD System provides the analytical basis for determination of plant thermal limits and provides protection against fuel damage limits during a Rod Withdrawal Error (RWE) event. Bases for LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6 discuss in more detail how the SLs are protected by the CRD System.

Control Rod OPERABILITY satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

OPERABILITY of an individual control rod is based on a combination of factors, primarily the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator OPERABILITY is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion

BASES

LCO (continued)

times and therefore an inoperable accumulator does not immediately require declaring a control rod inoperable.

Although not all control rods are required to be OPERABLE to satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the design basis transient and accident analyses.

APPLICABILITY

In MODES 1 and 2, the control rods are assumed to function during a DBA or transient and are therefore required to be OPERABLE in these MODES. In MODES 3, 4, and 5, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions. Control rod requirements in MODE 6 are located in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

The ACTIONS Table is modified by two Notes. The first Note allows separate Condition entry for each control rod. This is acceptable since the Required Actions for each Condition provides appropriate compensatory actions for each inoperable control rod. Complying with the Required Actions may allow for continued operation, and subsequent inoperable control rods governed by subsequent Condition entry and application of associated Required Actions. The second Note requires entry into applicable Conditions and Required Actions of LCO 3.7.6, "Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions," when inoperable control rods result in inoperability of the SRI function. This Note is necessary to ensure that the ACTIONS for an inoperable SRI are taken if the control rod inoperability affects the OPERABILITY of the SRI function. Otherwise, pursuant to LCO 3.0.6, these ACTIONS would not be entered even when the LCO 3.7.6 is not met. Therefore, Note 2 is added to require the proper actions are taken.

STD COL 16.0-1-A 3.1.3-1

A.1, A.2, and A.3

A control rod is stuck if it will not insert by either FMCRD motor torque or hydraulic scram pressure. A control rod is not made inoperable by a failure of the FMCRD motor if the rod is capable of hydraulic scram. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted. The Required Actions are modified by a Note that allows a stuck control rod to be

BASES

ACTIONS (continued)

bypassed in the Rod Control and Information System (RC&IS) to allow continued operation. SR 3.3.2.1.9 provides additional requirements when control rods are bypassed in the RC&IS to ensure compliance with the RWE analysis.

STD COL 16.0-1-A 3.1.3-1

The associated control rod drive must be disarmed and isolated within 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable amount of time to perform the Required Action in an orderly manner.

The motor drive may be disarmed by bypassing the rod in the RC&IS or disconnecting its power supply. Isolating the control rod from scram prevents damage to the CRD and surrounding fuel assemblies should a scram occur. The control rod can be isolated from scram by isolating it from its associated HCU. Two CRDs sharing an HCU can be individually isolated from scram.

STD COL 16.0-1-A 3.1.3-1

Monitoring of the insertion capability of withdrawn control rods must be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RC&IS. SR 3.1.3.2 and SR 3.1.3.3 perform periodic tests of the control rod insertion capability of withdrawn control rods. Testing within 24 hours ensures a generic problem does not exist. This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.2 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RC&IS, since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RC&IS (LCO 3.3.2.1, "Control Rod Block Instrumentation") when below the actual LPSP. The allowed Completion Time of 24 hours from discovery of Condition A, concurrent with THERMAL POWER greater than the LPSP of the RC&IS, provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a design basis transient or accident require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must

BASES

ACTIONS (continued)

therefore be evaluated (by measurement or analysis) with the stuck control rod withdrawn and the highest worth control rod or control rod pair assumed to be fully withdrawn.

STD COL 16.0-1-A 3.1.3-1

The allowed Completion Time of 72 hours to verify SDM is adequate considering that with a single control rod stuck in the withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 5 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 or 4 conditions. In addition, Required Action A.2 performs a movement test on each remaining withdrawn control rod to ensure that no additional control rods are stuck. Therefore, the 72 hour Completion Time to perform the SDM verification in Required Action A.3 is acceptable.

B.1

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (however, they do not need to be isolated from scram). Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be disarmed by bypassing the rod in the RC&IS or disconnecting its power supply. Required Action C.1 is modified by a Note that allows control rods to be bypassed in the RC&IS if required to allow insertion of the inoperable control rods and continued operation. SR 3.3.2.1.9 provides

ACTIONS (continued)

additional requirements when the control rods are bypassed to ensure compliance with the RWE analysis.

The allowed Completion Times are reasonable considering the small number of allowed inoperable control rods and provides time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

During reactor startup at less than 50% control rod density, the Ganged Withdrawal Sequence Restrictions (GWSR) analysis requires inserted control rods not in compliance with GWSR to be separated by at least two OPERABLE control rods in all directions including the diagonal (Ref. 2). Out-of-sequence control rods may increase the potential reactivity worth of a control rod, or gang of control rods, during a RWE and therefore the distribution of inoperable control rods must be controlled. Therefore, if two or more inoperable control rods are not in compliance with GWSR and not within separation limits as specified in the COLR, actions must be taken to restore compliance with GWSR or restore the control rods to OPERABLE status. A Note has been added to the Condition to clarify that the Condition is not applicable when > 10% RTP since the GWSR is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6.

E.1

If any Required Action and associated Completion Time of Condition A, C, D, or E are not met or nine or more inoperable control rods exist, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 in an orderly manner from full power without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

Determining the position of each control rod is required to ensure adequate information on control rod position is available to the operator for determining CRD OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, or by the use of other appropriate methods. The 24-hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indication in the control room.

SR 3.1.3.2 and SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod two notches (i.e., 4 steps) and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These surveillances are not required when below the actual LPSP of the RC&IS since the step insertions may not be compatible with the requirements of the Ganged Withdrawal Sequence Restrictions (LCO 3.1.6) and the RC&IS (LCO 3.3.2.1). The 7 day Frequency of SR 3.1.3.2 is based on experience related to changes in CRD performance and the ease of performing step testing for fully withdrawn control rods. Partially withdrawn control rods are tested with a 31 day Frequency based on the potential power reduction required to allow the control rod movement and considering the large testing sample of SR 3.1.3.2. Furthermore, the 31 day Frequency takes into account operating experience related to changes in CRD performance. At any time, if a control rod is immovable, a determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

SR 3.1.3.4

STD COL 16.0-1-A 3.1.3-2

This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The CHANNEL FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," overlaps this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to

BASES

SURVEILLANCE REQUIREMENTS (continued)

demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.5

Coupling verification is performed to confirm the integrity of the coupling between the control rod and the hollow piston and to ensure the control rod will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity, since only an uncoupled hollow piston can reach the overtravel position. The verification is required to be performed prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect the coupling.

This Frequency is acceptable because of the mechanical integrity of the bayonet coupling design of the FMCRDs. The bayonet coupling can only be engaged/disengaged by performing a 45° rotation of the FMCRD mechanism relative to the control rod. This is normally performed by rotating the FMCRD mechanism 45° from below the vessel with the control rod kept from rotating by the orificed fuel support that has been installed from above. Once the coupling is engaged and the FMCRD middle flange is bolted into place, the 45° rotation required for uncoupling cannot be accomplished unless the associated orificed fuel support is removed (which would allow for the control rod to be rotated from above) or the FMCRD middle flange is unbolted (which would allow for rotation of the FMCRD mechanism from below). Therefore, after FMCRD maintenance in which the FMCRD is uncoupled and then recoupled or after the orificed fuel support has been moved, it is required to perform a coupling verification. Thereafter, it is not necessary to check the coupling integrity again until the FMCRD maintenance work has resulted in uncoupling and recoupling, or the orificed fuel support has been moved.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 27, GDC 28, and GDC 29.
2. NEDE-33243P-A, ESBWR Control Rod Nuclear Design, Revision 2, September 2010.
3. Section 4.3.3.
4. Section 4.6.1.
5. Section 5.2.2.
6. Chapter 15.

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System controls reactivity changes during abnormal operational transients to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrammed by positive means, using hydraulic pressure exerted on the CRD piston.

A single hydraulic control unit (HCU) powers the scram action of one or two fine motion control rod drives (FMCRDs). When a scram signal is initiated, control air is vented from the scram valve in each hydraulic control unit (HCU), allowing it to open by spring action. High pressure nitrogen then raises the piston within the HCU accumulator and forces the displaced water through the scram piping to the connected FMCRDs. Inside each FMCRD, the high pressure water lifts the hollow piston off the ball-nut and drives the control rod into the core. A buffer assembly stops the hollow piston at the end of its stroke. Departure from the ball-nut releases spring-loaded latches in the hollow piston that engage slots in the guide tube. These latches support the control rod in the inserted position. The control rod cannot be withdrawn until the ball-nut is driven up and engaged with the hollow piston. Stationary fingers on the ball-nut then cam the latches out of the slots and hold them in the retracted position. A scram action is complete when every FMCRD has reached their fully inserted position.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 2, 3, 4, 5, and 6. The design basis transient and accident analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Surveillance of each individual control rod's scram time ensures that the scram reactivity assumed in the design basis transient and accident analyses can be met.

STD COL 16.0-1-A 3.1.4-1

The scram function of the CRD System protects the Fuel Cladding Integrity Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM

BASES

APPLICABLE SAFETY ANALYSES (continued)

CRITICAL POWER RATIO (MCPR)"), and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded. For reactor pressures above 7.340 MPaG (1065 psig), the scram function is designed to insert negative reactivity at a rate fast enough to prevent the Fuel Cladding Integrity SL being exceeded during the analyzed limiting power transient. For reactor pressures below 7.340 MPaG (1065 psig) the scram function is assumed to function during the Rod Withdrawal Error (RWE) event (Ref. 6) and, therefore, also provides protection against violating fuel damage limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). For the reactor vessel overpressure protection analysis, the scram function, along with the Safety Relief Valves, ensures that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control Rod Scram Times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

STD COL 16.0-1-A 3.1.4-1

The scram time limits specified in Table 3.1.4-1 (in the accompanying LCO) are required to ensure that the scram reactivity assumed in the design basis transient and accident analysis is met. The scram time limits are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram time limits are specified relative to percent insertion. The scram time limits are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the hollow piston passes a specific location and then opens ("dropout") as the hollow piston tube travels upward. Verification of the specified scram times in Table 3.1.4-1 is accomplished through measurement of the "dropout" times.

STD COL 16.0-1-A 3.1.4-1

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3).

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3, 4,

BASES

APPLICABILITY (continued)

and 5, the control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 6 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling".

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analyses. Therefore, the affected control rod must be declared inoperable, and the Actions of LCO 3.1.3 entered.

STD COL 16.0-1-A 3.1.4-1

SURVEILLANCE REQUIREMENTS

All four SRs of this LCO are modified by a Note stating that during a single control rod or control rod pair scram time Surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod or control rod pair scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in design basis transient and accident analyses is based on assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 6.55 MPaG (950 psig) demonstrates acceptable scram times for the transients analyzed in References 4 and 5.

Scram insertion times increase with increasing reactor pressure because of the competing effects of reactor steam dome pressure and stored accumulator energy. Demonstration of adequate scram times at reactor steam dome pressure ≥ 6.55 MPaG (950 psig) helps to ensure that the scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following a refueling or after a shutdown

BASES

SURVEILLANCE REQUIREMENTS (continued)

greater than 120 days or longer, control rods are required to be tested before exceeding 40% RTP following the shutdown. This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by work on control rods or the CRD System.

SR 3.1.4.2

STD COL 16.0-1-A 3.1.4-1

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods, the sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be inoperable. If more than 7.5% of the sample is declared to be inoperable based on the acceptance criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (e.g., 7.5% of the sample size) is satisfied, or until the total number of inoperable control rods (throughout the core, from all Surveillances) results in entering Action D of LCO 3.1.3. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data were previously tested in a sample. The 200 day Frequency is based on operating experience that has shown that control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable based on the additional Surveillances done on the control rod drives at more frequent intervals in accordance with LCO 3.1.3 and LCO 3.1.5, "Control Rod Scram Accumulators."

SR 3.1.4.3

When work is performed on a control rod or the CRD System that could affect the scram insertion time, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed before declaring the control rod OPERABLE. The required scram time testing must demonstrate that the affected control rod is still within acceptable limits. The limits for reactor pressures < 7.340 MPaG (1065 psig) are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 7.340 MPaG (1065 psig). Limits for

BASES

SURVEILLANCE REQUIREMENTS (continued)

STD COL 16.0-1-A 3.1.4-1

reactor pressures ≥ 7.340 MPaG (1065 psig) are found in Table 3.1.4-1.

Specific examples of work that could affect the scram times include (but are not limited to) the following: removal of any CRD for maintenance or modification, replacement of a control rod, and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator isolation valve, or check valves in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rods over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

After fuel movement has occurred within the affected cell or after work on a control rod or the CRD System has occurred that can affect scram time, the scram insertion time must be confirmed. Testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 6.55 MPaG (950 psig). Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 will be satisfied with one test. For a control rod affected by work performed while shut down, however, a zero pressure and a high pressure test may be required. This testing ensures that the control rod scram performance is acceptable for operating reactor pressure conditions prior to withdrawing the control rod for continued operation. Alternatively, a test during hydrostatic pressure testing could also satisfy both criteria. When fuel movement within the reactor pressure vessel occurs, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage, it is expected that all control rods will be affected.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rods at the different conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. Section 4.2.4.
3. Section 4.3.3.
4. Section 4.6.1.
5. Section 5.2.2.
6. Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Control Rod Scram Accumulators

BASES

BACKGROUND

The control rod scram accumulators are part of the Control Rod Drive (CRD) System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a single or pair of control rods associated with a specific hydraulic control unit (HCU) at any reactor vessel pressure. The accumulator is a hydraulic cylinder with a free-floating piston. The piston separates the water used to scram the control rods from the nitrogen, which provides the required energy. The scram accumulators are necessary to scram the control rods within the required insertion times of LCO 3.1.4, "Control Rod Scram Times."

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 1, 2, 3, and 4. The design basis transient and accident analyses assume that all of the control rods scram at a specified insertion rate. OPERABILITY of each individual control rod scram accumulator, along with LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.4, ensures that the scram reactivity assumed in the design basis transient and accident analyses can be met. The existence of an inoperable accumulator may invalidate prior scram time measurements for the associated control rods.

The scram function of the CRD System, and, therefore, the OPERABILITY of the accumulators, protects the Fuel Cladding Integrity Safety Limit (see Bases for LCO 3.2.2 "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). Also, the scram function at low reactor vessel pressure (i.e., startup conditions) provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control").

Control Rod Scram Accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.

APPLICABILITY

In MODES 1 and 2, the scram function is required for mitigation of DBAs and transients and, therefore, the scram accumulators must be OPERABLE to support the scram function. In MODES 3, 4, and 5, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram accumulator OPERABILITY under these conditions. Requirements for scram accumulators in MODE 6 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the Required Actions for each Condition provide appropriate compensatory action for each inoperable control rod scram accumulator. Complying with the Required Actions may allow for continued operation and subsequent inoperable accumulators governed by subsequent Condition entry and application of associated Required Actions.

A.1

With one control rod scram accumulator inoperable, the scram function could become severely degraded because the accumulator is the primary source of scram force for the associated control rod or rod pair at all reactor pressures. In this event, the associated control rod or rod pair is declared inoperable and LCO 3.1.3 entered. This would result in requiring the affected control rod or rod pair to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3. The allowed Completion Time of 8 hours is considered reasonable, based on the large number of control rods available to provide the scram function. Additionally, an automatic reactor scram function is provided on sensed low pressure in the scram accumulator charging water header (see LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"). This anticipatory reactor trip protects against the possibility

BASES

ACTIONS (continued)

of significant pressure degradation (and thus reduced scram force) concurrently in multiple control rod scram accumulators due to a transient in the CRD hydraulic system.

B.1

With two or more control rod scram accumulators inoperable, the scram function could become severely degraded because the accumulators are the primary source of scram force for the control rods at all reactor pressures. In this event, the associated control rods are declared inoperable and LCO 3.1.3 entered. This would result in requiring the affected control rods to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is considered reasonable based on engineering judgment considering the low probability of a DBA or transient occurring while the affected accumulators are inoperable.

C.1

The reactor mode switch must be immediately placed in the shutdown position if any Required Action and associated Completion Time cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the Required Action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the accumulator pressure be checked every 7 days to ensure that adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of
STD COL 16.0-1-A 3.1.5-1
12.75 MPaG (1849 psig) reflects a bounding value based on the ABWR CRD HCU accumulator minimum pressure value. Using

BASES

SURVEILLANCE REQUIREMENTS (continued)

the ABWR minimum pressure value is bounding and thereby justified based on:

a. ESBWR frictional pressure loss is similar to the ABWR design,

a. ESBWR control rod is lighter in weight than the ABWR control rod,

a. ESBWR normal reactor pressure on scram initiation is similar to ABWR, and

a. Mechanical losses should be bounded, since the basic mechanical designs are the same.

Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account other indications available in the control room.

REFERENCES

1. Section 4.3.3.
2. Section 4.6.1.
3. Section 5.2.2.
4. Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM), (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount of reactivity addition that could occur during a control rod withdrawal, specifically the Rod Withdrawal Error (RWE) event.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the RWE are summarized in Reference 1. RWE analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the RWE analysis. The RWM provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the RWE analysis are not violated.

Control rod patterns analyzed in Reference 1 follow the Ganged Withdrawal Sequence Restrictions (GWSR). The GWSR is applicable from the condition of all control rods fully inserted to 10% RTP. For GWSR, the control rods are required to be moved in groups, with all OPERABLE control rods assigned to specific groups required not to exceed an allowable maximum position difference until all OPERABLE control rods of the group have reached a defined withdrawal position. The GWSR are defined to minimize the maximum incremental control rod worths without being overly restrictive during normal plant operation.

Prevention or mitigation of positive reactivity insertion events is necessary to limit energy deposition in the fuel to prevent significant fuel damage which could result in undue release of radioactivity. Analysis of the GWSR (Ref. 1) has demonstrated that the 712 J/g (170 cal/g) limit for evaluating the radiological consequences of an RWE will not be violated. The analysis also evaluated the effect of fully inserted inoperable control rods not in compliance with the sequence to allow a limited number (i.e., eight) and distribution of fully inserted inoperable control rods.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Rod Pattern Control satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Compliance with the prescribed control rod sequences minimizes the potential consequences of a RWE by limiting the initial conditions to those consistent with the GWSR. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the GWSR.
APPLICABILITY	Compliance with GWSR is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% of RTP. When THERMAL POWER is > 10% of RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 712 J/g (170 cal/g) limit for evaluating the radiological consequences of an RWE. In MODES 3, 4, 5, and 6, since the reactor is shutdown and only a total of one control rod or control rod pair can be withdrawn from core cells containing fuel assemblies, adequate SDM ensures the reactor will remain subcritical.
ACTIONS	<u>A.1 and A.2</u> With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, actions may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of failed resolvers, or a power reduction to ≤ 10% RTP before establishing the correct control rod pattern (i.e., a pattern that complies with the GWSR). The number of OPERABLE control rods not in compliance with the prescribed sequence is limited to eight to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence. When the control rod pattern is not in compliance with the prescribed sequence, all control rod movement should be stopped except for moves needed to correct the control rod pattern, or scram if warranted. Required Action A.1 is modified by a Note which allows control rods to be bypassed in Rod Control & Information

BASES

ACTIONS (continued)

System (RC&IS) to allow the affected control rods to be returned to their correct position. This ensures that the control rods will be moved to the correct position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. OPERABILITY of control rods is determined by compliance with LCO 3.1.3, LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out-of-sequence control rods and the low probability of a RWE occurring during the time the control rods are out of sequence.

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worths than withdrawals. Required Action B.1 is modified by a Note that allows the affected control rods to be bypassed in RC&IS in accordance with SR 3.3.2.1.9 to allow insertion only. With nine or more OPERABLE control rods not in compliance with GWSR, the reactor mode switch must be placed in the shutdown position within one hour. With the reactor mode switch in shutdown, the reactor is shut down and as such does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is a reasonable time to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a RWE occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

Verification that the control rod pattern is in compliance with the GWSR at a 24 hour Frequency ensures that the assumptions of the RWE analyses are met. The 24 hour Frequency of this Surveillance was developed considering that the primary check of the control rod pattern compliance with the GWSR is performed by the RWM (LCO 3.3.2.1). The RWM provides control rod blocks to enforce the required control

BASES

SURVEILLANCE REQUIREMENTS (continued)	rod sequence and is required to be OPERABLE when operating. ≤ 10% RTP.
REFERENCES	1. Section 15.3.8.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Liquid Standby Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide both manual and automatically initiated capability for bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient), to a subcritical condition with the reactor in the most reactive xenon-free state without taking credit for control rod movement. The SLC System satisfies portions of the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS). The automatic initiation signals applicable to ATWS mitigation are addressed in the Availability Control Manual.

The SLC System is also credited in the loss of coolant accident (LOCA) to provide makeup water to the Reactor Pressure Vessel (RPV). The emergency core cooling system (ECCS) and the SLC are designed to flood the core during a LOCA to provide required core cooling. By providing core cooling following a LOCA, the ECCS, including SLC, in conjunction with the containment, limit the release of radioactive materials to the environment following a LOCA. The injection of sodium pentaborate is also credited for buffering the pH in containment pools following a LOCA.

The SLC System contains two identical and separate trains. Each train provides 50% of the required SLC injection capacity required for ATWS. Each train also provides 50% of the required SLC injection capacity assumed to be available for a LOCA. Each train consists of a nitrogen-pressurized accumulator containing sodium pentaborate solution (SPBS). Each train is connected to the RPV through piping that includes two, normally open, SLC accumulator isolation valves in series and two injection squib valves in parallel. The SPBS is injected into the RPV by firing squib valves.

Each SLC injection line is connected to an RPV supply header. Each header includes spargers with a total of eight nozzles. Each nozzle penetrates the shroud and is provided with two holes that discharge the SPBS into the core. This arrangement, together with a high nozzle injection velocity, assures proper distribution of the SPBS within the core bypass region. Boron in sodium pentaborate acts as a neutron poison reducing and halting the fission process. The SLC

BASES

BACKGROUND (continued)

System is passive and requires no high pressure pump or external standby AC power for SPBS injection. Power for the safety functions of the SLCS is derived from the safety-related 120 VAC electrical systems. Adequate functioning of the SLC System requires only one of the two injection valves open in each SLC train.

Each SLC train includes two injection squib valves, which are arranged in parallel. Actuation of either injection squib valve provides the required flow path for injection of the associated SLC train. Each of the injection squib valves are equipped with two safety-related squib initiators that are actuated by the safety-related Safety System Logic and Control (SSLC) described in the Bases for LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Emergency Core Cooling System (ECCS) Actuation."

Each SLC train includes two, normally open, accumulator isolation valves, which are arranged in series, and close on a low accumulator level signal from any two of the four SLC accumulator level sensors associated with each accumulator. Closure of either accumulator isolation valve is sufficient to prevent the injection of nitrogen from the accumulator into the RPV. The normally open accumulator isolation valves receive an open signal to support the ECCS injection function.

Power to each of the safety-related squib initiators on each SLC injection squib valve is supplied from a different division of the DC and Uninterruptible AC Electrical Power Distribution. As such, at least one safety-related initiator in each SLC injection squib valve will be associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."

SLC is designed to ensure that no single active component failure will cause inadvertent initiation or prevent initiation and successful operation.

APPLICABLE SAFETY ANALYSES

The ECCS function of the SLC System is automatically initiated as described in the Bases for LCO 3.3.5.1. During a LOCA, SLC provides makeup water to the RPV to ensure the core is cooled (Ref. 2). The injection of sodium pentaborate is also credited for buffering the pH in containment pools following a LOCA (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, a quantity of isotopically enriched SPBS is injected, which produces the equivalent shutdown capability as concentration of 760 ppm of natural, non-enriched SPBS in the reactor core at 20°C (68°F). The volume and concentration limits are calculated such that the required concentration is achieved accounting for dilution in the RPV with the reactor water level conservatively taken at the elevation of the bottom edge of the main steamlines. This result is then increased by a factor of 1.25 to provide a 25% general margin to discount potential nonuniformities of the mixing process within the reactor (Ref. 4). That result is then increased by a factor of 1.15 to provide a further margin of 15% to discount potential dilution by the Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System when activated in the shutdown cooling mode.

The SLC System satisfies Criteria 3 and 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods. In addition, the SLC System provides makeup water to the RPV to mitigate the consequences of a LOCA. For ATWS requirements, the OPERABILITY of the SLC System is based on the conditions of the borated solution in each accumulator and the availability of a pressurized accumulator and a flow path from each accumulator to the RPV, including the OPERABILITY of the instrumentation and valves. For a LOCA, the volume of water in both SLC accumulators is necessary for makeup and core cooling.

Two SLC trains are required to be OPERABLE, each containing two OPERABLE injection squib valves and two OPERABLE accumulator isolation valves in the open position and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

OPERABILITY of each injection squib valve requires OPERABILITY of one safety-related initiator associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6. OPERABILITY of each accumulator isolation valve requires OPERABILITY of safety-related closing initiators and safety-related opening

BASES

LCO (continued)	initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6.
APPLICABILITY	In MODES 1 and 2, the SLC System is needed for its reactor shutdown capability. Reactor shutdown capability is not required in MODES 3, 4 and 5 because the reactor mode switch is in shutdown and control rods cannot be withdrawn because a control rod block is applied. When a control rod block is not applied, LCO 3.10.3, "Control Rod Withdrawal – Hot/Stable Shutdown," and LCO 3.10.4, "Control Rod Withdrawal – Cold Shutdown," in conjunction with LCO 3.1.1, "SHUTDOWN MARGIN," provide adequate controls to ensure the reactor remains subcritical. In MODES 1, 2, 3, and 4, the ECCS function of SLC System is required to provide additional inventory for RPV water makeup and core cooling.

ACTIONS

A.1

STD COL 16.0-1-A 3.1.7-1

With one injection squib valve flow path in one or more trains inoperable, the squib valve flow path(s) must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE squib valve flow paths are adequate to perform the shutdown function. However, the overall reliability is reduced because a single failure in the remaining OPERABLE squib valve flow paths could result in reduced SLC System capability. The 7 day Completion Time is based on engineering judgment considering the availability of one OPERABLE flow path in each train that is capable of performing the intended SLC System function and the low probability of a Design Basis Accident (DBA) or transient occurring during this period.

STD COL 16.0-1-A 3.1.7-1

B.1

With one accumulator isolation valve inoperable for closing in one or more trains, the accumulator isolation valve(s) must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE accumulator isolation valve is capable of performing the required safety function. However, the overall reliability is reduced because a single failure in the remaining OPERABLE isolation valve could result in injection of nitrogen into the RPV. The 7 day Completion Time is based on engineering judgment considering

BASES

ACTIONS (continued)

the availability of one OPERABLE flow path in each train that is capable of performing the intended SLC System function and the low probability of a DBA or transient occurring during this period.

C.1 and C.2

STD COL 16.0-1-A 3.1.7-1

If one or more SLC trains are inoperable for reasons other than Condition A or B (e.g., one or both accumulator isolation valve in the closed position), or if any Required Action and associated Completion Time of Condition A or B are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on plant design, to reach MODE 5 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 are 24 hour Surveillances verifying certain characteristics of the SLC System (e.g., the volume of sodium pentaborate solution in the accumulator, temperature of the room with piping and valves containing boron solution, and nitrogen volume and pressure in each accumulator), thereby ensuring the SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure the proper SPBS volume and temperature and accumulator nitrogen volume and pressure are maintained. Maintaining a minimum specified SPBS temperature is important in ensuring that the boron remains in solution and does not precipitate in the accumulators or in the injection piping. Maintaining a minimum accumulator nitrogen volume and pressure will ensure the full injection of solution inventory at rated reactor pressure. The 24 hour Frequency of these SRs was based on operating experience that has shown that there are relatively slow variations room temperature and alarms that monitor volume and pressure.

SR 3.1.7.4

This SR requires verification every 31 days of the continuity of one safety-related initiator associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6 for each injection squib valve.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 31 day Frequency is acceptable because either of the two injection squib valves in each train is capable of initiating SLC injection. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each SLC injection valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in either division does not disable the SLC system because the parallel injection squib valve will still be opened by the initiator in another other division.

SR 3.1.7.5

SR 3.1.7.5 verifies each valve in the system is in its correct position but does not apply to the squib valves. Verifying the correct alignment for manual, power-operated, and automatic valves in the SLC System flow path provides assurance that the proper flow paths will exist for system operation. This Surveillance does not apply to valves which are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves which cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct positions. The 31 day Frequency for SR 3.1.7.5 is appropriate because the valves are operated under procedural control and it was chosen to provide added assurance that the valves are in the correct positions.

This SR is modified by a Note allowing an SLC flow path to be isolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve to open the valve when a valid actuation signal is indicated.

SR 3.1.7.6

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure

SURVEILLANCE REQUIREMENTS (continued)

the proper concentration of boron exists in the accumulator. SR 3.1.7.6 must be performed any time boron or water is added to the accumulator solution to establish that the boron solution concentration is within the specified limits. This Surveillance must be performed anytime the temperature is restored to within the limits of Figure 3.1.7-1, to ensure no significant boron precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because the boron solution is not expected to change concentration between surveillances.

SR 3.1.7.7

The SLC trains are required to actuate both automatically and manually to perform their design function. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the SLC operates as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components, including isolation of the SLC accumulator when accumulator level is low. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed SLC function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This is acceptable because SLC valves are subject to the Inservice Test Program.

SR 3.1.7.8

This SR requires a CHANNEL CALIBRATION of the accumulator level instrumentation channels that actuate SLC accumulator isolation on low level. CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the required

SURVEILLANCE REQUIREMENTS (continued)

nominal trip setpoint within the "as-left tolerance" to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the Setpoint Control Program. The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.1.7.9

This Surveillance ensures that there is a functioning flow path for the boron solution from the accumulator to the RPV. The Surveillance may be performed in overlapping steps, provided the entire flow path is verified within the specified Frequency. The flow path may be verified by flow tests using demineralized water to prevent injecting boron into the RPV, or a combination of flushing, visual inspection, or boroscopic inspection.

This SR is accompanied by a Note that excludes squib valve actuation as a requirement for this SR to be met. This is acceptable because squib valves are flanged, allowing access to both sides of the valves for verification that the flow path is free of obstructions. The squib valves are tested under the ASME OM Code and are included in the Inservice Testing Program (Ref. 6).

Each SLC train includes two parallel flow paths, each controlled by an injection squib valve. The Frequency, 24 months on a STAGGERED TEST BASIS for each flow path, ensures that the flow path tested every 24 months is alternated so that each flow path is tested every 96 months.

The 24 month Frequency is necessary because of the need to perform this Surveillance during a plant outage. The 24 month Frequency is acceptable because of the low probability that the piping will be blocked due to precipitation of the boron from solution. The saturation temperature of the solution is less than 15.5°C (60°F) (Ref. 4) and requirements in SR 3.1.7.2 conservatively ensure that the SPBS remains above saturation temperature. Additionally, the SLC mixing pump and sample connection may be used to verify flow through the outlet of the accumulator.

SR 3.1.7.10

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic

BASES

SURVEILLANCE REQUIREMENTS (continued)	tests on the granular sodium pentaborate to verify the actual B-10 enrichment must be performed prior to addition to the SLC accumulator to ensure that the proper B-10 atom percent is being used.
REFERENCES	1. 10 CFR 50.62. 2. Section 6.3.3. 3. Section 15.4.4. 4. Section 9.3.5. 5. Section 7.8.1.1. 6. Section 3.9.6.1.

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B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on the LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs). Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure or inability to cool the fuel will not occur during the anticipated operating conditions identified in Reference 1.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1 and 2. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 52.47(a)(2)(iv). The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 1). The Fuel Cladding Integrity Safety Limit ensures that fuel damage caused by severe overheating of the fuel cladding is avoided.

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to the operating limit specified in the COLR. The analysis also includes allowances for short-term transient operation above

BASES

APPLICABLE SAFETY ANALYSES (continued)	the operating limit to account for AOOs, plus an allowance for densification power spiking. The LHGR operating limit is power and feedwater temperature dependent. Therefore, the LHGR operating limits specified in the COLR include power dependent limits and feedwater temperature dependent limits. The LHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.
APPLICABILITY	The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 25% RTP.
ACTIONS	A.1 If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident (DBA) occurring simultaneously with the LHGR out of specification. B.1 If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The 4 hour Completion Time is reasonable, based on engineering

BASES

ACTIONS (continued)	judgment, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.2.1.1 The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER reaches ≥ 25% RTP is acceptable given the large inherent margin to operating limits at low power levels.
REFERENCES	1. Section 15.2. 2. Chapter 4.

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B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The Fuel Cladding Integrity Safety Limit (FCISL) is established as greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experiences boiling transition (Ref. 1), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, mass flux, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in Chapter 4. To ensure that the FCISL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the critical power ratio (CPR) transient uncertainty. The types of transients evaluated are decrease in core coolant temperature, increase in reactor pressure, increase in reactor coolant inventory, decrease in reactor coolant inventory. The steady-state and CPR transient uncertainties and the uncertainties in monitoring and simulating the core operating state are incorporated by the statistical model (Ref. 2) to determine the required operating limit MCPR. The transient analyses assume that the feedwater control system is in automatic mode; therefore, if the feedwater control system is in manual mode, then the MCPR LCO is not met.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The MCPR operating limits are power and feedwater temperature dependent. Therefore, the MCPR operating limits specified in the COLR include power dependent limits and feedwater temperature dependent limits. The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The MCPR operating limits specified in the COLR are the result of fuel design and transient analyses.
APPLICABILITY	The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 25% RTP, the moderator void fraction is very small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the FCISL is not exceeded even if a limiting transient occurs. Studies of the variation of limiting transient behavior have been performed over the range of operational conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 25% RTP. Comparison of test data at low pressure and flow conditions to expected bundle operating conditions at less than 25% RTP has determined that the bundle powers would have to increase by multiples of three or more prior to reaching critical bundle powers. When in MODE 2, the Startup Range Neutron Monitor (SRNM) provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

BASES

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant will be operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The 4 hour Completion Time is reasonable, based on engineering judgment, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER reaches ≥ 25% RTP is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. NUREG-0562, "Fuel Rod Failure as a Consequence of Departure From Nucleate Boiling or Dryout," June 1979.

2. NEDC-33237P-A, GE14 for ESBWR-Critical Power Correlation, Uncertainty, and OLMCPR Development, Revision 5, September 2010.

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B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS is designed to initiate a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits, including the requirements for determining that the channel

BACKGROUND (continued)

is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, Setpoint Control Program (SCP)."

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least conservative value of the as-found setpoint that a channel can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$,

BASES

BACKGROUND (continued)

Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The RPS, as shown in Reference 1, is divided into four redundant divisions of sensor (instrument) channels, trip logics and trip actuators, and two divisions of manual scram controls and scram logic circuitry. The sensor channels, divisions of trip logic, divisions of trip actuators, and associated portions of the divisions of scram logic circuitry together constitute the RPS automatic scram and backup scram initiation logic. The divisions of manual scram controls and associated portions of the divisions of scram logic circuitry together constitute the RPS manual scram and backup scram initiation logic. The automatic and manual scram initiation logics are independent of each other and use diverse methods and equipment to initiate a reactor scram.

<u>Instrument (Sensor) Channels</u>

Equipment within a sensor channel consists of sensors (i.e., transducers or switches), Digital Trip Module (DTM) and

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multiplexers. The sensors within each channel detect abnormal operating conditions and send analog (or discrete) output either directly to the RPS cabinets or to Remote Multiplexer Units (RMUs) within the associated division. The RMU within each division performs analog-to-digital conversion on analog signals and sends the digital or digitized analog output values of the monitored variables to the DTM for trip determinations within the associated RPS Instrument (sensor) channel in the same division. The DTM in each sensor channel compares individual monitored variable values with trip setpoint values and for each variable sends a separate trip/no trip output signal to the functional Trip Logic Units (TLUs) in the four divisions of trip logic. Equipment within a single division is powered from the safety-related power source of the same division. OPERABILITY requirements for instrument channels are addressed in LCO 3.3.1.1.

Divisions of Trip Logic

Equipment within an RPS division of trip logic consists of TLUs, manual switches, bypass units (BPUs) and Output Logic Units (OLUs). The TLUs perform the automatic scram initiation logic, checking for two-out-of-four coincidence of trip conditions in any set of instrument channel signals coming from the four divisions of DTMs or from isolated digital inputs from the four divisions of the Neutron Monitoring System (NMS), and outputting a trip signal if any one of the two-out-of-four coincidence checks is satisfied. The automatic scram initiation logic for any trip is based on the reactor operating mode status and channel trip conditions and bypass conditions. Each TLU, besides receiving isolated digital input trip signals from the four divisions of DTMs, also receives digital input signals from the BPU and other control interfaces in the same division.

The various manual switches provide the operator with the means to enforce interlocks within RPS trip logic for special operation, maintenance, testing, and system reset. The BPUs perform bypass and interlock logic for the division of sensors bypass and the division of logic bypass. Each BPU sends its divisional sensor bypass signal to the TLU of the same division and an isolated divisional sensor bypass signal to the TLUs of the other three divisions. Each BPU sends its divisional logic bypass signal to the OLU of the same division and an isolated divisional logic bypass signal to the OLUs of the other three divisions. The OLUs perform division trip, seal-in, reset and trip test functions. Each

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OLU receives bypass inputs from the BPU and trip inputs from the TLU of the same division. Each OLU provides trip outputs to the trip actuators.

Equipment within a division of trip logic is powered from the same division of safety-related power source. However, different pieces of equipment are powered from separate low voltage dc power supplies in the same division. OPERABILITY requirements for the Divisions of Trip Logic are addressed in LCO 3.3.1.2, "Reactor Protections System (RPS) Actuation," with the exception of the digital trip function, which is addressed in LCO 3.3.1.1.

Divisions of Trip Actuators

Equipment within a division of trip actuators includes load drivers for automatic primary scram and output contactors for the initiation of backup scram. The RPS includes two physically separate and electrically independent divisions of trip actuators that receive inputs from the four divisions of the OLU. The load driver outputs are arranged in the primary scram logic circuitry, which is between the scram solenoids and scram solenoid 120 VAC power source. When in a tripped state, the load drivers within a division interconnect with the OLU of all other divisions to form an arrangement (connected in series and in parallel in two separate groups) that results in two-out-of-four scram logic. Reactor scram occurs if load drivers associated with any two or more divisions receive trip signals from the OLUs.

Output contactors are used for back-up scram actuators, scram-follow initiation, and scram reset permissive actuators. When in a tripped state, the output contactors cause the backup scram valve solenoids to energize. The output contactors of the backup scram are arranged in a two-out-of-four configuration similar to that described above for the primary scram load drivers. Backup scram is diverse in power source and function to primary scram.

A manual switch associated with each Division of Trip Actuators provides means to reset the seal-in at the input of all trip actuators in the same division. The reset does not have any effect if the conditions that caused the division trip have not cleared when a reset is attempted. All manual resets are inhibited for ten seconds to allow sufficient time for scram completion.

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OPERABILITY requirements for the load drivers are addressed in LCO 3.3.1.2. OPERABILITY requirements for the backup scram output contactors are not addressed within the Technical Specifications.

Divisions of Manual Scram Controls

OPERABILITY requirements for the Divisions of Manual Scram Controls are addressed in LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Trip Actuation."

Divisions of Scram Logic Circuitry

The two divisions of primary scram logic circuitry are powered from independent and separate power sources. One of the two divisions of scram logic circuitry distributes division 1 safety-related 120 VAC power to the A solenoids of the hydraulic control units (HCUs). The other division of scram logic circuitry distributes division 2 safety-related 120 VAC power to the B solenoids of the HCUs. The HCUs (which include the scram pilot valves and the scram valves, including their solenoids) are, components of the CRD system. A full scram of control rods associated with a particular HCU occurs when both A and B solenoid of the HCU are de-energized.

One scram pilot valve is located in the Hydraulic Control Unit (HCU) for each control rod drive pair. Each scram pilot valve is operated by two solenoids, with both solenoids normally energized. The scram pilot valve controls the air supply to the scram inlet valve for the associated control rod drive pair. When either of two scram pilot valve solenoids is energized, air pressure holds the scram valve closed and therefore, both scram pilot valve solenoids must be de-energized to cause a control rod pair to scram. The scram valve controls the supply for the control rod drive (CRD) water during a scram.

OPERABILITY requirements for components of the Divisions of Scram Logic Circuitry are addressed in LCO 3.1.3, "Control Rod OPERABILITY."

The RPS is designed to provide reliable single-failure proof capability to automatically or manually initiate a reactor scram while maintaining protection against unnecessary scrams resulting from single failures. The RPS satisfies the single-failure criterion even when one entire division of

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sensors is bypassed and/or when one of the four automatic RPS trip logic divisions is out of service.

The AC electrical power required by the four divisions of RPS is supplied from four pairs of physically separate and electrically independent uninterruptible safety-related 120 VAC buses. Each RPS division uses the two independent power sources from the same division. Either source of power per division can support the associated RPS division.

Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level, reactor vessel steam dome pressure, neutron flux, main steam line isolation valve (MSIV) position, drywell pressure, scram accumulator charging water header pressure, turbine stop valve position, turbine control valve closure, main condenser vacuum, bus voltage, and suppression pool temperature, as well as reactor mode switch in shutdown position and manual scram signals. The reactor mode switch in shutdown position and manual scram signal inputs to the scram logic are addressed in LCO 3.3.1.3.

All average power range monitor (APRM)/oscillation power range monitor (OPRM) and startup range neutron monitor (SRNM) trip decisions are made within the Neutron Monitoring System (NMS). This is done on a divisional basis and the results are then sent directly to the TLUs. Thus, each NMS division sends only two inputs to the divisional TLUs, one for APRM/OPRM trip/no-trip and one for SRNM trip/no-trip. A divisional APRM/OPRM or SRNM may be tripped due to any of the monitored variables exceeding its trip setpoint. The RPS two-out-of-four trip decision is then made, not on a per variable basis, but on an APRM/OPRM tripped or SRNM tripped basis, by looking at the four divisions of APRM/OPRM and four divisions of SRNM. All bypasses of the SRNMs and APRMs/OPRMs are performed within and by the NMS. Refer to LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," and LCO 3.3.1.5, "Neutron Monitoring System (NMS) Actuation," for the NMS specifications.

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The actions of the RPS are assumed in the safety analyses of Reference 2. The RPS initiates a reactor scram when monitored parameter values exceed predetermined values specified in the SCP to preserve the integrity of the fuel cladding, preserve the integrity of the reactor coolant

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

pressure boundary, and preserve the integrity of the containment by minimizing the energy that must be absorbed following a LOCA.

RPS Instrumentation satisfies the requirements of Selection Criterion 3 of 10 CFR 50.36(c)(2)(ii). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual RPS instrumentation Functions specified in Table 3.3.1.1-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate. The actual setpoint is calibrated consistent with the SCP. Each channel must also respond within its assumed response time.

$NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the actual setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

The OPERABILITY of RPS Actuation, manual scram features, the NMS features, and scram pilot valves and associated solenoids, and backup scram valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES specified in the Table which may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE.

RPS is required to be OPERABLE in MODES 1 and 2, and MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. During normal operation in MODES 3, 4, and 5, all control rods are fully inserted and the Reactor Mode Switch - Shutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. In MODE 6, control rods withdrawn from a core cell containing no fuel assemblies do not affect the

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reactivity of the core and therefore are not required to have the capability to scram. Provided all control rods otherwise remain inserted, the RPS function is not required. In this condition the required SDM (LCO 3.1.1, "SHUTDOWN MARGIN") and refuel position one-rod/rod-pair-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") ensure no event requiring RPS will occur. Under these conditions, the RPS function is not required to be OPERABLE.

The specific Applicable Safety Analyses, LCO and Applicability discussions are listed below on a Function-by-Function basis.

This Specification covers the RPS instrumentation that encompasses the sensor channels up through the DTMs.

Although there are four channels of RPS instrumentation for each function, only three channels of RPS instrumentation for each function are required to be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems -Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE RPS instrumentation channels, and because each RPS division is associated with and receives power from only one of the four electrical divisions.

1. Neutron Monitor System Input - Startup Range Neutron Monitors

The SRNM is a part of the NMS. The NMS Functions associated with the SRNM are described in the Bases of LCO 3.3.1.4. The SRNM provides diverse protection for the Rod Worth Minimizer (RWM) in the Rod Control and Information System (RC&IS), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out-of-sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 3). The SRNM provides mitigation of the neutron flux excursion in the control rod withdrawal event during startup (Ref. 4).

The SRNMs are also capable of limiting other reactivity excursions during startup, such as cold-water injection events, although no credit is specifically assumed.

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Three channels of Neutron Monitoring System Input - Startup Range Neutron Monitors are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal.

This Function is required to be OPERABLE in the MODES where the SRNM Functions are required.

2. Neutron Monitor System Input - Average Power Range Monitors/Oscillation Power Range Monitors (OPRMs)

The APRMs and OPRMs are a part of the NMS. The NMS Functions associated with the APRMs and OPRMs are described in the Bases of LCO 3.3.1.4.

Three channels of NMS inputs from the NMS (APRMs/OPRMs) arranged in a two-out-of-four logic are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal.

This Function is required to be OPERABLE in the MODES where the APRM and OPRM Functions are required (LCO 3.3.1.4).

3. Scram Accumulator Charging Water Header Pressure - Low-Low

To maintain the continuous ability to scram, the scram accumulator charging water header maintains the hydraulic scram accumulators at a high pressure. The scram valves under this condition remain closed, so that no flow passes through the scram accumulator charging water header. Pressure in the scram accumulator charging water header is monitored. The Scram Accumulator Charging Water Header Pressure - Low-Low Function initiates a scram if a significant degradation in the scram accumulator charging water header pressure occurs. During a scram, the water discharge from the accumulators goes into the reactor, and thus against reactor pressure. Therefore, fully charged hydraulic control units (HCUs) are essential for assuring reactor scram. After a reactor scram, this Function can be bypassed from the operator's console to reset the RPS, allowing the scram valves to close and the HCUs to be re-pressurized.

Low-Low scram accumulator charging water header pressure signals are initiated from four pressure sensors located at the scram accumulator charging water header. The Scram

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Accumulator Charging Water Header Pressure – Low-Low Allowable Value is chosen to provide sufficient margin to the capability to scram.

Three channels of Scram Accumulator Charging Water Header Pressure - Low-Low Function are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE when the scram capability is required in MODES 1 and 2, and MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

4. Reactor Vessel Steam Dome Pressure - High

An increase in the Reactor Pressure Vessel (RPV) pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the integrity of the Reactor Coolant System (RCS) pressure boundary. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure - High Function initiates a scram for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis, the APRM Fixed Neutron Flux - High Function is assumed to terminate the MSIV Closure event and, along with the safety relief valves, limits the peak RPV pressure to less than the ASME Code limits.

High reactor pressure signals are initiated from four pressure sensors that sense reactor pressure. The Reactor Vessel Steam Dome Pressure -High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Three channels of Reactor Vessel Steam Dome Pressure - High Function are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the Reactor Coolant System is pressurized and the potential for pressure increase exists.

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5. Reactor Vessel Water Level - Low, Level 3

Low Reactor Vessel (RPV) water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level - Low, Level 3 Function is assumed to be available in various design basis line break analyses and in loss of feedwater events, however it is a secondary scram signal to Loss of Power Generation Bus. The reactor scram reduces the amount of energy required to be absorbed and assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low, Level 3, signals are initiated from four differential pressure sensors that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Three channels of Reactor Vessel Water Level - Low, Level 3, Function are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value is selected to ensure that for transients involving loss of all normal feedwater flow, the core will not be uncovered.

The Function is required in MODES 1 and 2 where considerable energy exists in the reactor coolant system resulting in the limiting transients and accidents.

6. Reactor Vessel Water Level - High, Level 8

High RPV water level indicates a potential problem with the feedwater level control system, resulting in the addition of reactivity associated with the introduction of a significant amount of relatively cold feedwater. Therefore, a scram is initiated at Level 8 to ensure the safety analyses are met. The Reactor Vessel Water Level - High, Level 8 Function is directly assumed in the analysis of feedwater controller failure, maximum demand (Ref. 5).

Reactor Vessel Water Level - High, Level 8, signals are initiated from four differential pressure sensors that sense

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the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level - High, Level 8 Allowable Value is specified to ensure the safety analyses criteria are met.

Three channels of the Reactor Vessel Water Level - High, Level 8, are required to be OPERABLE when THERMAL POWER is ≥ 25% RTP to ensure no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 25% RTP, this Function is not required since MCPR is not a concern below 25% RTP.

7. Main Steam Isolation Valve - Closure (Per Steam Line)

Main Steam Isolation Valve (MSIV) closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a MSIV closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 6, the Average Power Range Monitor Fixed Neutron Flux - High Function, along with the safety relief valves, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in References 7 and 8. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Isolation Condenser System (ICS), assures that the safety analyses assumptions are met.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. On each MSL, two position switches are mounted on the inboard MSIV and two position switches are mounted on the outboard MSIV. Each of the position switches on any one MSL is associated with a different RPS divisional sensor channel. The logic for the Main Steam Isolation Valve - Closure Function is arranged such that either the inboard or outboard valve on two or more of the main steam lines (MSLs) must close in order for a scram to occur.

The Main Steam Isolation Valve - Closure (per Steam Line) Function Allowable Value is specified to ensure that a scram

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occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

Three channels of Main Steam Isolation Valve - Closure (per Steam Line) Function are required to be OPERABLE to ensure no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 because with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close. In MODE 2 the heat generation rate is low enough that the other diverse RPS Functions provide sufficient protection.

8. Drywell Pressure - High

High pressure in the drywell could indicate a break in the Reactor Coolant System pressure boundary. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and to the drywell. The Drywell Pressure - High Function is assumed to be available for LOCA events inside the drywell and is credited in the inadvertent operation of a depressurization valve. High drywell pressure signals are initiated from four pressure sensors that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside the drywell or an opened depressurization valve.

Three channels of Drywell Pressure - High Function are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the reactor coolant system resulting in the limiting transients and accidents.

9. Suppression Pool Temperature - High

High temperature in the suppression pool could indicate a break in the RCS pressure boundary or an opened safety relief valve. A reactor scram is initiated to reduce the amount of energy being added to the containment. The Suppression Pool Temperature - High Function is taken credit for in the analysis of an inadvertent opening of a safety relief valve (Ref. 9).

High suppression pool temperature signals are initiated from four divisions of temperature sensors located in the

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suppression pool. Four channels of safety-related divisional temperature signals, each formed by the average value of a group of thermocouples installed evenly inside the suppression pool, provide the suppression pool temperature data for automatic scram initiation. When the established limits of high temperature are exceeded in two of the four divisions, a scram initiation and indication signals are generated. The temperature sensors provide analog output signals to the RMU, which in turn provides the equivalent digital signal to the appropriate DTM. The temperature sensors are components of the Containment Monitoring System (CMS). The suppression pool water level signals are provided along with the suppression pool temperature signals. When water level drops below selected temperature sensors, the exposed sensors are logically bypassed such that only sensors below the water level are utilized to determine the averaged temperature signal to the RPS.

The Allowable Value was selected considering the maximum operating temperature and to be indicative of an inadvertently opened safety relief valve.

Three channels of Suppression Pool Temperature - High Function are required to be OPERABLE to ensure no single instrument failure will preclude a scram from this Function on a valid signal. There are a total of 64 suppression pool temperature switches that make up the four channels of Suppression Pool Temperature - High Function (16 suppression pool temperature switches per channel). For a channel of the Suppression Pool Temperature - High Function to be OPERABLE, 12 of the 16 assigned Suppression Pool Temperature switches must be OPERABLE. The Function is required in MODES 1 and 2 where considerable energy exists in the reactor coolant system.

10. Turbine Stop Valve - Closure

Closure of the turbine stop valves (TSV) results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves with insufficient turbine bypass valve capacity available. The Turbine Stop Valve - Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 10. For this event, the reactor scram reduces the amount of energy required to be absorbed

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and ensures that the fuel cladding integrity Safety Limit is not exceeded.

Turbine Stop Valve - Closure signals are initiated by the separate valve stem position switches on each of the four turbine stop valves. Each position switch provides an open/close contact output signal through hardwired connections to the DTM in one of the four RPS sensor channels. The Turbine Stop Valve – Closure trip occurs in each division of trip logic when any two or more position switches detect the turbine stop valve closure. The Function is enabled at THERMAL POWER > 40% RTP. This is accomplished automatically by an analog simulated thermal power signal from the NMS. This Function is also automatically bypassed if sufficient turbine bypass valves are open within a preset time delay after the initiation of the trip signal. The analog simulated thermal power signal from NMS is also used to determine the required bypass capacity.

The Turbine Stop Valve - Closure Allowable Value is selected to be high enough to detect imminent TSV closure thereby reducing the severity of the subsequent pressure transient.

Three channels of Turbine Stop Valve - Closure Function are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function even if one TSV should fail to close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 40% RTP. This Function is not required when THERMAL POWER is < 40% RTP since the Reactor Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Functions are adequate to maintain the necessary safety margins.

11. <u>Turbine Control Valve Fast Closure, Trip Oil Pressure - Low</u>

Fast closure of the turbine control valves (TCVs) results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves with insufficient turbine bypass valve capacity available. The Turbine Control Valve Fast Closure, Trip Oil Pressure -Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 11. For this event, the reactor scram reduces

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the amount of energy required to be absorbed and ensures that the fuel cladding integrity Safety Limit is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure - Low signals are initiated by the hydraulic trip system pressure at each control valve. There is one pressure sensor associated with each control valve. Each pressure sensor provides a signal through hard-wired connections to the DTM in each of the four RPS sensor channels. This Function must be enabled at THERMAL POWER ≥ 40% RTP. This is accomplished automatically by an analog simulated thermal power signal from NMS. This Function is automatically bypassed if sufficient turbine bypass valves are open within a preset time delay after the initiation of the trip signal. The analog simulated thermal power signal from NMS is also used to determine the required bypass capacity.

The Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Three channels of Turbine Control Valve Fast Closure, Trip Oil Pressure -Low Function, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ 40% RTP. This Function is not required when THERMAL POWER is < 40% RTP since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Functions are adequate to maintain the necessary safety margins.

12. <u>Main Condenser Pressure - High</u>

The Main Condenser Pressure - High Function is provided to help ensure the fuel cladding integrity Safety Limit is not exceeded by reducing the core energy in anticipation that the high condenser pressure will also trip the main turbine and prevent bypass valve operation. The Main Condenser Pressure - High Function is the primary scram signal for the loss of condenser vacuum event analyzed in Reference 12. For this event, the reactor scram reduces the amount of energy required to be absorbed by the main condenser and helps to ensure the fuel cladding integrity Safety Limit is not exceeded by reducing the core energy prior to the fast closure of the turbine stop valves. The reactor scram at Main Condenser Pressure - High will initiate to shut off steam flow to the main condenser to protect the main turbine and to

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avoid the potential for rupturing the low-pressure turbine casing.

Main condenser pressure signals are derived from four pressure sensors that sense the pressure in the condenser. Each pressure sensor provides an analog output signal through hard-wired connections to the DTM in each of the four RPS sensor channels. The Allowable Value was selected to reduce the severity of a loss of main condenser vacuum event by anticipating the transient and scramming the reactor at a higher vacuum than the setpoints that close the turbine stop valves and bypass valves.

Three channels of Main Condenser Pressure - High Function are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODE 1 since, in this MODE, a significant amount of core energy can be rejected to the main condenser.

13. Power Generation Bus Loss

The plant electrical system has four redundant power generation buses that operate at 13.8 kV. These buses supply power for the feedwater pumps and circulating pumps. In MODE 1, at least three of the four buses must be powered. Power generation bus loss signals are derived from four voltage sensors. If the voltage sensor (one per division) on each bus senses a low voltage below the required level, indicating that less than three buses are operating above the requirement level, a scram is initiated after a preset delay time. This delay time is to accommodate for the auto-transfer from the Unit Auxiliary Transformer (UAT) transformer feed to the Reserve Auxiliary Transformer (RAT) feed. When the power generation buses are not operating at or above the required level, the feedwater pumps would be tripped and feedwater flow would be lost. Purpose of this scram on losing feedwater flow is to mitigate the reactor water level drop to Level 1 following the loss of feedwater pump function. This scram will terminate additional steam production within the vessel before Level 3 is reached.

The Allowable Value was selected high enough to detect a loss of voltage in order to mitigate the reactor water level drop to Level 1 following the loss of feedwater pump function.

Three channels of Power Generation Bus Loss Function are required to be OPERABLE to ensure that no single instrument

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

failure will preclude a scram from this Function on a valid signal. The Function is required in MODE 1 where considerable energy exists in the reactor coolant system resulting in the limiting transients and accidents. During MODE 2, 3, 4, 5, and 6, the core energy is significantly lower.

14. Feedwater Temperature Biased Simulated Thermal Power – High

The Feedwater Temperature Biased Simulated Thermal Power – High Function is provided to help ensure the fuel cladding Safety Limit is not exceeded in the event of a significant decrease in feedwater temperature (Ref. 13). Feedwater temperature is measured by four separate temperature sensors mounted on each FW line. Each feedwater temperature sensor is connected to a separate RPS instrumentation channel and is associated with a separate RPS electrical division. The RPS uses feedwater temperature to generate a simulated thermal power trip setpoint that is a function of feedwater temperature.

Three channels of the Feedwater Temperature Biased Simulated Thermal Power – High Function are required to be OPERABLE when THERMAL POWER is ≥ 25% RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 25% RTP, this Function is not required since MCPR is not a concern below 25% RTP.

15. Simulated Thermal Power Biased Feedwater Temperature – High

The Simulated Thermal Power Biased Feedwater Temperature – Low Function is provided to help ensure the fuel cladding Safety Limit is not exceeded in the event of a significant decrease in feedwater temperature (Ref. 13). Feedwater temperature is measured by four separate temperature sensors mounted on each FW line. Each feedwater temperature sensor is connected to a separate RPS instrumentation channel and is associated with a separate RPS electrical division. The RPS uses the simulated thermal power signal from NMS to generate a feedwater temperature trip setpoint that is a function of simulated thermal power.

Three channels of the Simulated Thermal Power Biased Feedwater Temperature – High Function are required to be OPERABLE when THERMAL POWER is ≥ 25% RTP to ensure that no

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 25% RTP, this Function is not required since MCPR is not a concern below 25% RTP.

16. Simulated Thermal Power Biased Feedwater Temperature – Low

The Simulated Thermal Power Biased Feedwater Temperature – Low Function is provided to help ensure the fuel cladding Safety Limit is not exceeded in the event of a significant decrease in feedwater temperature (Ref. 13). Feedwater temperature is measured by four separate temperature sensors mounted on each FW line. Each feedwater temperature sensor is connected to a separate RPS instrumentation channel and is associated with a separate RPS electrical division. The RPS uses the simulated thermal power signal from NMS to generate a feedwater temperature trip setpoint that is a function of simulated thermal power.

Three channels of the Simulated Thermal Power Biased Feedwater Temperature – Low Function are required to be OPERABLE when THERMAL POWER is ≥ 25% RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 25% RTP, this Function is not required since MCPR is not a concern below 25% RTP.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS Instrumentation channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable RPS Instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided which allows separate Condition entry for each inoperable RPS Instrumentation channel.

A.1

The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors

BASES

ACTIONS (continued)

available to provide trip signals, the redundancy of the RPS design, and the low probability of an event requiring a reactor scram during this interval. However, this out of service time is only acceptable provided the associated Function still maintains RPS trip capability (refer to Required Action B.1 Bases). If the inoperable instrumentation channel cannot be restored to OPERABLE status within the 12-hour Completion Time, the associated instrument channel must be verified to be in trip. This is acceptable because verifying the affected RPS instrument channel in trip conservatively compensates for the inoperability by placing the RPS in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

Alternatively, if it is not desirable to verify the associated instrument channel in trip (as in the case where it is desired to place the affected channel of sensors in bypass), Condition B must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

Required Action B.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1 if the Required Action and Completion Time of Condition A are not met or if multiple, inoperable, untripped required channels (i.e., two or more required channels for most Functions) for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip such that the RPS logic will generate a trip signal from the given Function on a valid signal.

The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed.

C.1, D.1, E.1, F.1, and G.1

If the required RPS instrumentation channel(s) is not restored to OPERABLE status, or the affected instrumentation channel is not in trip within the allowed Completion Time, or if RPS trip capability is not maintained, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable,

BASES

ACTIONS (continued)

based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Actions C.1 and D.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

The RPS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECKs every 12 hours supplement less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The RPS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the channels.

SR 3.3.1.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the required channel responds to the measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 14.

RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the sensor channels up through the DTMs and overlaps the testing required by SR 3.3.1.2.2 to ensure complete testing of instrument channels and actuation circuitry.

STD COL 16.0-1-A 3.3.1.1-2

RPS RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the required channels associated with each division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of

BASES

SURVEILLANCE REQUIREMENTS (continued)

instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 7, Figure 7.2-1.
2. Chapter 15.
3. Subsection 7.7.2.
4. Subsection 15.3.8.
5. Subsection 15.3.2.
6. Subsection 5.2.2.
7. Subsection 15.3.3.
8. Subsection 15.2.2.7.
9. Subsection 15.3.13.
10. Subsection 15.2.2.5.
11. Subsection 15.2.2.3.
12. Subsection 15.2.2.8.
13. Subsection 15.3.1.
14. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.1.2 Reactor Protection System (RPS) Actuation

BASES

BACKGROUND	The RPS is designed to initiate a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding, preserve the integrity of the reactor coolant pressure boundary, and preserve the integrity of the containment by minimizing the energy that must be absorbed following a LOCA. This can be accomplished either automatically or manually. A detailed description of the RPS instrumentation and RPS actuation logic is provided in the Bases for LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." This Specification provides requirements for the RPS actuation circuitry that consists of the Divisions of Trip Logic (with the exception of OPERABILITY of the digital trip function, which is addressed in LCO 3.3.1.1), and the Divisions of Trip Actuators (except for OPERABILITY of the backup scram load drivers which are not addressed within the Technical Specifications).
APPLICABLE SAFETY ANALYSES	The actions of the RPS are assumed in the safety analyses of Reference 1. The RPS initiates a reactor scram when monitored parameter values exceed the trip setpoints to preserve the integrity of the fuel cladding, preserve the integrity of the reactor coolant pressure boundary, and preserve the integrity of the containment by minimizing the energy that must be absorbed following a LOCA. RPS actuation divisions support the OPERABILITY of the RPS Instrumentation, "LCO 3.3.1.1, Reactor Protection System (RPS) Instrumentation" and therefore are required to be OPERABLE. RPS Actuation satisfies the requirements of Selection Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Although there are four RPS automatic actuation divisions, only three RPS automatic actuation divisions are required to be OPERABLE to ensure no single automatic actuation division failure will preclude a scram to occur on a valid signal. The three required divisions are those divisions associated with

BASES

LCO (continued)

the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems -Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is still met with three OPERABLE RPS actuation divisions, and because each RPS division is associated with and receives power from only one of the four electrical divisions. This Specification provides requirements for the RPS actuation circuitry that consists of the Divisions of Trip Logic, and the Divisions of Trip Actuators.

The OPERABILITY of scram pilot valves and associated solenoids, and backup scram valves are not addressed by this LCO. The OPERABILITY of the RPS Instrumentation is covered in LCO 3.3.1.1.

APPLICABILITY

Three RPS automatic actuation divisions are required to be OPERABLE in MODES 1 and 2, and in MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. During normal operation in MODES 3, 4 and 5, all control rods are fully inserted and the Reactor Mode Switch – Shutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. In MODE 6, control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and, therefore, are not required to have the capability to scram. Provided all other control rods remain inserted, the RPS function is not required. In this condition, the required SDM (LCO 3.1.1, "SHUTDOWN MARGIN") and refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") ensure that no event requiring RPS will occur. Under these conditions, the RPS function is not required to be OPERABLE.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS automatic actuation divisions. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable RPS automatic actuation divisions provide appropriate

ACTIONS (continued)

compensatory measures for separate inoperable divisions. As such, a Note has been provided which allows separate Condition entry for each inoperable RPS automatic actuation division.

A.1

The 12-hour Completion Time is acceptable based on engineering judgment considering the redundancy of the RPS automatic actuation divisions and the low probability of an event requiring reactor scram during this interval. However, this out of service time is only acceptable provided the RPS maintains automatic trip capability (refer to Required Action B.1 Bases). If the inoperable division cannot be restored to OPERABLE status within the 12-hour Completion Time, the affected actuation division must be verified to be in trip. This is acceptable because verifying the affected RPS actuation division in trip conservatively compensates for the inoperability by placing the RPS in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

Alternatively, if it is not desirable to verify the affected actuation division in trip (as in the case where it is desired to place the affected actuation division in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

If any Required Action and associated Completion Time of Condition A is not met in MODE 1 or 2, or if multiple, inoperable, untripped required divisions of RPS actuation (i.e., two or more required divisions) result in the RPS automatic actuation capability not maintained in MODE 1 or 2, the plant must be brought to a MODE in which the LCO does not apply. RPS automatic actuation capability is considered to be maintained when sufficient required actuation divisions are OPERABLE or in trip such that the RPS logic will generate a trip signal on a valid signal. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

BASES

ACTIONS (continued)

C.1

With automatic actuation capability not maintained in MODE 6 or if any Required Action and associated Completion Time of Condition A is not met in MODE 6, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the RPS Actuation divisions, including the two-out-of four function of the Trip Logic Unit (TLU), Output Logic Unit (OLU), and Load Drivers (LDs) for a specific division. The functional testing of control rods, in LCO 3.1.3, overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.3.1.2.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 2.

STD COL 16.0-1-A 3.3.1.2-1

RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the RPS actuation circuitry that consists of the Divisions of Trip Logic, and the Divisions of Trip Actuators and overlaps the testing required by SR 3.3.1.1.4 to ensure complete testing of instrument channels and actuation circuitry.

BASES

SURVEILLANCE REQUIREMENTS (continued)

RPS RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that each required division is alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 15.
2. Section 15.2.

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B 3.3 INSTRUMENTATION

B 3.3.1.3 Reactor Protection System (RPS) Manual Actuation

BASES

BACKGROUND

The RPS is designed to initiate a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

Manual scram is accomplished either via two manual scram push buttons (Division 1 and Division 2 manual actuation channels) or by placing the reactor mode switch in the shutdown position. The reactor mode switch is a single switch that initiates a scram when the switch is in the shutdown position by interrupting power to the circuits affected by each manual scram pushbutton (Division 1 and Division 2 Reactor Mode Switch -Shutdown actuation channels). The two manual scram pushbuttons each de-energize a separate path for the four scram groups such that when individually actuated a half-scram condition results, and when actuated together a full scram results. Placing the mode switch in shutdown immediately results in full scram by interrupting power to the circuits affected by each manual scram pushbutton. If a full scram occurs, scram reset is prevented for 10 seconds. This 10-second delay on reset ensures that the scram function will be completed.

One scram pilot valve is located in the Hydraulic Control Unit (HCU) for each control rod drive pair. Each scram pilot valve is operated by two solenoids, with both solenoids normally energized. The scram pilot valve controls the air supply to the scram inlet valve for the associated control rod drive pair. When either of two scram pilot valve solenoids is energized, air pressure holds the scram valve closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod pair to scram. The scram valve controls the supply for the control rod drive (CRD) water during a scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS.

BASES

BACKGROUND (continued)	The OPERABILITY of scram pilot valves and associated solenoids is addressed in LCO 3.1.3, "Control Rod OPERABILITY." OPERABILITY of the backup scram valves is not addressed within the Technical Specifications.
APPLICABLE SAFETY ANALYSES	RPS Manual Actuation does not satisfy any criteria of 10 CFR 50.36(c)(2)(ii), but is retained for the overall redundancy and diversity of the RPS as required by the NRC-approved licensing basis.
LCO	Two manual actuation channels and two Reactor Mode Switch -Shutdown actuation channels as specified in Table 3.3.1.3-1 are required to be OPERABLE to retain the overall redundancy and diversity of the RPS.
APPLICABILITY	The manual actuation Functions are required to be OPERABLE whenever the RPS automatic instrumentation is required to be OPERABLE in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"). RPS is required to be OPERABLE in MODES 1 and 2, and MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. During normal operation in MODES 3, 4, and 5, all control rods are fully inserted and the Reactor Mode Switch - Shutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. In MODE 6, control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all control rods otherwise remain inserted, the RPS function is not required. In this condition the required SDM (LCO 3.1.1, "SHUTDOWN MARGIN") and refuel position one-rod-out/rod-pair-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") ensures no event requiring RPS will occur. Under these conditions, the RPS function is not required to be OPERABLE.
ACTIONS	A Note has been provided to modify the ACTIONS related to RPS manual actuation Functions. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of

BASES

ACTIONS (continued)

the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable RPS manual actuation Functions provide appropriate compensatory measures for separate inoperable Functions. As such, a Note has been provided which allows separate Condition entry for each inoperable RPS manual actuation Function.

A.1

If one manual actuation channel is inoperable the capability to shut down the unit with the associated Function is lost. However, manual shutdown capability is retained by the OPERABLE Function. The 12-hour Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 12-hour Completion Time is acceptable based on engineering judgment considering the availability of the automatic functions and alternative manual trip methods and the low probability of an event requiring manual reactor scram during this interval. The four RPS automatic divisions also have manual trip capability provided by four divisional trip switches that are located in positions easily accessible for optional use by the plant operator.

Alternatively, if it is not desired to place the inoperable channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in a scram), Condition C or D, as appropriate, must be entered and its Required Action taken.

B.1

With one channel of the manual scram Function inoperable and one channel of the Reactor Mode Switch -Shutdown position Function inoperable, the affected channels must be verified in trip immediately. In this Condition, both required manual actuation Functions are inoperable.

Alternatively, if it is not desired to place the inoperable channels in trip (e.g., as in the case where placing the inoperable channels in trip would result in a scram, Condition C or D, as appropriate, must be entered and its Required Action taken.

BASES

ACTIONS (continued)

C.1

With both manual actuation channels inoperable in one or both Functions in MODE 1 or 2 or if any Required Action and associated Completion Time of Condition A or B is not met in MODE 1 or 2, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

D.1

With both manual actuation channels inoperable in one or both Functions in MODE 6 or if any Required Action and associated Completion Time of Condition A or B is not met in MODE 6, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3.1

A CHANNEL FUNCTIONAL TEST is performed on each RPS Manual Scram Function channel to ensure that each channel will perform the intended Function. The Frequency of 7 days is based on the reliability of the RPS actuation logic and controls.

SR 3.3.1.3.2

A CHANNEL FUNCTIONAL TEST is performed on the Reactor Mode Switch - Shutdown Position Function to ensure that the Reactor Mode Switch will perform the intended Function. The Frequency of 24 months is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

BASES

REFERENCES	None.

Intentionally Blank

B 3.3 INSTRUMENTATION

B 3.3.1.4 Neutron Monitoring System (NMS) Instrumentation

BASES

BACKGROUND

The NMS Instrumentation provides input to the Reactor Protection System (RPS) when sufficient instrumentation channels indicate a trip condition. The RPS is designed to initiate a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA).

The protection and monitoring functions of the NMS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance. Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect the SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety function is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits, including the requirements for determining that the channel

BACKGROUND (continued)

is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors, which may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least conservative value of the as-found setpoint that a channel

BACKGROUND (continued)

can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the ALT and AFT will be maintained in the SCP, as required by Specification 5.5.11.

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The NMS is composed of the startup range neutron monitor (SRNM) and the average power range monitor (APRM). SRNM trip signals and APRM trip signals from each of the four divisions of NMS equipment are provided to the four divisions of RPS trip logic (Ref. 1).

The SRNM provides trip signals to the RPS to cover the range of plant operation from source range through startup range (i.e., more than 10% of reactor rated power). Three SRNM conditions, monitored as a function of the NMS, comprise the SRNM trip logic output to the RPS. These conditions are as follows: SRNM Neutron Flux High (high count rate when selected to the non-coincident mode); Neutron Flux Short (fast) Period; and SRNM inoperative. The SRNM Neutron Flux High (non-coincident mode) is not required in any accident analysis in Reference 2. Therefore, OPERABILITY of the SRNM Neutron Flux High (non-coincident mode) is not required by Technical Specifications and is addressed in plant

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BACKGROUND (continued)

procedures. The trip conditions from every SRNM associated with the same NMS division are combined into a single SRNM trip signal for that division. The specific condition that causes the SRNM trip output state is identified by the NMS and is not detectable within the RPS.

The SRNM consists of twelve fixed in-core regenerative fission chamber sensors, each with associated electronics to monitor the whole startup range (10 decades) of neutron flux. The twelve detectors are all located at fixed elevation slightly above the mid-plane of the fuel region, and are evenly distributed throughout the core. The twelve SRNM channels are divided into four NMS divisions. For each division, any one SRNM channel trip will result in an SRNM division trip. Each SRNM divisional output is provided to each of the four divisions two-out-of-four voters (NMS Trip Logic Unit). The NMS Trip Logic Unit determines whether there are sufficient SRNM divisions in trip (two-out-of-four logic). In addition, the twelve SRNM channels are divided into four bypass groups. There is one bypass group for each quadrant of the core, consisting of the three SRNMs located in that quadrant. A joystick type bypass switch ensures that no more than one SRNM in a quadrant can be simultaneously bypassed. Thus, up to four channels may be bypassed at any one time. There is no additional SRNM bypass capability at the divisional level; however, it is possible to bypass all three SRNMs within a division.

Each SRNM cabinet is redundantly powered by two uninterruptible divisional 120 VAC power sources from its associated electrical division; either source of power can support system operation.

The APRMs provide trip signals to the RPS to cover the range of plant operation from a few percent to greater than rated power. Three APRM conditions, monitored as a function of the NMS, comprise the APRM trip logic output to the RPS. These conditions are APRM Fixed Neutron Flux-High, Simulated Thermal Power - High, and APRM inoperative.

There are four APRM channels divided into four NMS divisions. For each division, any one APRM channel trip (high or inoperative) will result in a division trip. Each APRM divisional output is provided to each of the four divisions two-out-of-four voters (NMS Trip Logic Unit). The NMS Trip Logic Unit determines whether there are sufficient APRM divisions in trip (two-out-of-four logic). One APRM channel may be bypassed at any one time. When an APRM is

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bypassed, its associated Oscillation Power Range Monitor (OPRM) is also bypassed.

APRM channels receive power from its associated electrical division. Either of the two redundant uninterruptible power sources within a division can support APRM channel operation.

The OPRMs provide trip signals to the RPS to cover the range of plant operation from a few percent to greater than rated power. The OPRM trip protection includes algorithms that detect thermal hydraulic instability (flux oscillation with unacceptable amplitude and frequency).

There are four OPRM channels divided into four NMS divisions. The OPRM function resides in its associated APRM channel equipment. For each division, any one OPRM channel trip will result in a division trip.

Each OPRM divisional output is provided to each of the four divisions two-out-of-four voters (NMS Trip Logic Unit). The NMS Trip Logic Unit determines whether there are sufficient OPRM divisions in trip (two-out-of-four logic). When an APRM is bypassed, its associated OPRM is also bypassed. The OPRM function resides in the APRM equipment and receives the same redundant APRM power.

The APRMs, OPRMs, and the SRNM are part of the NMS instrumentation. The trip decisions are made within the NMS. This is done on a divisional basis and the results then sent directly to the RPS Trip Logic Units (TLUs). Thus, each NMS division sends only two inputs to the RPS divisional TLUs, one for APRM trip/no-trip (which includes the OPRM trip) and one for SRNM trip/no-trip. A divisional APRM (OPRM) or SRNM may be tripped due to any of the monitored variables exceeding its trip setpoint. The RPS two-out-of-four trip decision is then made, not on a per variable basis, but on an APRM (OPRM) tripped or SRNM tripped basis, by looking at the four divisions of APRM (OPRM) and four divisions of SRNM. All bypasses of the SRNMs and APRMs (OPRMs) are performed within and by the NMS.

The NMS is designed to provide reliable single-failure proof capability to automatically provide a trip signal to the RPS while maintaining protection against unnecessary trip signals resulting from single failures. The NMS satisfies the single-failure criterion even when one entire division

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of instrumentation is bypassed and/or when one of the four automatic actuation divisions is out of service.

This Specification addresses OPERABILITY of the SRNM channels from the sensors to the NMS Digital Trip Modules (DTMs) and up to each of the SRNM Trip Logic Units. This Specification addresses OPERABILITY of the APRM and OPRM channels from the sensors (local power range monitors, LPRMs) to the NMS Digital Trip Modules and up to each of the NMS Trip Logic Units, which house the APRM/OPRM logic. LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," addresses OPERABILITY requirements for NMS automatic actuation for the SRNM and the APRM/OPRM.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the NMS in conjunction with RPS are assumed in the safety analyses of References 2 and 3. The NMS provides a trip signal to RPS when monitored parameter values exceed predetermined values specified in the SCP to preserve the integrity of the fuel cladding, preserve the integrity of the reactor coolant pressure boundary, and preserve the integrity of the containment by minimizing the energy that must be absorbed following a LOCA.

NMS Instrumentation satisfies the requirements of Selection Criterion 3 of 10 CFR 50.36(c)(2)(ii). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the NMS and RPS as required by the NRC approved licensing basis.

The OPERABILITY of the NMS and RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.4-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate. The actual setpoint is calibrated consistent with the SCP. Each channel must also respond within its assumed response time.

$NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the actual setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The individual Functions are required to be OPERABLE in the MODES specified in the Table which may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE.

Although there are four divisions of NMS instrumentation for each function, only three divisions of NMS instrumentation for each function are required to be OPERABLE. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE NMS instrumentation divisions, and because each NMS division is associated with and receives power from only one of the four electrical divisions.

The specific Applicable Safety Analyses, LCO and Applicability discussions are listed below on a Function-by-Function basis.

1.a. Startup Range Neutron Monitor (SRNM) Neutron Flux - Short Period

The SRNM subsystem is part of the NMS. The SRNMs monitor neutron flux levels from cold shutdown condition to high neutron flux range with the LPRM/APRM on scale and with sufficient overlap of flux indication between the SRNMs and the APRMs. The SRNMs monitor the power level over the range from source range to more than 10% RTP. The SRNM subsystem will generate a scram trip signal to prevent fuel damage in the event of any abnormal positive reactivity insertion transients while operating in the startup power range. This trip signal is to be generated for an excessive neutron flux increase rate, i.e., short reactor period. The setpoint of this trip is determined such that under the worst positive reactivity insertion event, fuel integrity is always protected. The worst bypass or out of service condition of the SRNM subsystem is considered in determining the setpoints. In the startup power range, the most significant source of positive reactivity change is due to control rod withdrawal. The SRNM provides diverse protection for the Rod Worth Minimizer (RWM) in the Rod Control and Information System (RC&IS), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

result in an unacceptable neutron flux excursion (Ref. 4). The SRNM provides mitigation of the neutron flux excursion.

The SRNMs are also capable of limiting other reactivity excursions during startup such as cold-water injection events although no credit is specifically assumed.

The SRNM consists of twelve fixed in-core regenerative fission chamber sensors, each with associated electronics to monitor the whole startup range (10 decades) of neutron flux. The twelve detectors are all located at fixed elevation about the mid-plane of the fuel region, and are evenly distributed throughout the core. The twelve SRNM channels are divided into four NMS divisions. For each division, any one SRNM channel trip will result in an SRNM division trip. Therefore, two SRNM instrument channels are required to be OPERABLE in each required NMS division. Each SRNM divisional output is provided to each of the four divisions (NMS Trip Logic Unit). The NMS Trip Logic Unit determines whether there are sufficient SRNM divisions in trip (two-out-of-four logic). In addition, the twelve SRNM channels are divided into four bypass groups. There is one bypass group for each quadrant of the core, consisting of the three SRNMs located in that quadrant. A joystick type bypass switch ensures that no more than one SRNM in a quadrant can be simultaneously bypassed. Thus, up to four channels may be bypassed at any one time. There is no additional SRNM bypass capability at the divisional level; however, it is possible to bypass all of the SRNMs within a division.

Three divisional channels of each SRNM Function, with two separate channels per division, are required to be OPERABLE to ensure no single instrument failure will preclude a scram from these Functions on a valid signal.

The Allowable Value for the Startup Range Neutron Monitor (SRNM) Neutron Flux - Short Period Function is set to mitigate the consequences of a rod withdrawal error.

The SRNM Neutron Flux - Short Period Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 1, the Average Power Range Monitor Fixed Neutron Flux - High Function and the Automated Thermal Limit Monitor (ATLM) provides protection against reactivity transients. The SRNM Neutron Flux - Short Period Function is required to be OPERABLE in MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. During normal

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

operation in MODES 3, 4, and 5, all control rods are fully inserted and the Reactor Mode Switch - Shutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all control rods otherwise remain inserted, the SRNM function is not required. In this condition the required SDM (LCO 3.1.1, "SHUTDOWN MARGIN") and refuel position one-rod/rod-pair-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") ensures no event requiring RPS will occur. Under these conditions, the SRNM Function is not required to be OPERABLE.

1.b. <u>SRNM - Inop</u>

This trip signal provides assurance that a minimum number of SRNMs are OPERABLE. Anytime a SRNM detector high voltage drops below a preset level or when a module is disconnected an inoperative trip signal will occur unless the SRNM is bypassed.

This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

Three divisional channels of the SRNM Inop Function, with two separate channels per division, are required to be OPERABLE to ensure no single instrument failure will preclude a scram from these Functions on a valid signal.

This Function is required to be OPERABLE when the SRNM Neutron Flux - Short Period Function is required.

2.a. <u>APRM Fixed Neutron Flux - High, Setdown</u>

The APRM channels receive input signals from the LPRMs within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RATED THERMAL POWER. For operation at low power (i.e., MODE 2), the APRM Fixed Neutron Flux - High Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

transients in this power range. For most operation at low power levels, the APRM Fixed Neutron Flux - High, Setdown Function will provide a secondary scram to the SRNM Neutron Flux - High Function because of the relative setpoints. With the SRNM near its high power range, it is possible that the APRM Fixed Neutron Flux - High, Setdown Function will provide the primary trip signal for a core wide increase in power.

The control rod withdrawal event during startup (Ref. 4) assumes the failure of the SRNM instrumentation and shows that the APRM Fixed Neutron Flux - High, Setdown Function is capable of maintaining the peak fuel enthalpy to within limits so that no fuel damage results. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (Safety Limit 2.1.1.1) when operating at low reactor pressure and low core flow. It therefore indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

Three channels of APRM Fixed Neutron Flux - High, Setdown are required to be OPERABLE to ensure no single failure will preclude a scram from this Function on a valid signal. In addition, sufficient LPRM inputs are required to be OPERABLE to provide adequate coverage of the entire core.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The APRM Fixed Neutron Flux - High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn. In MODE 1, the Average Power Range Monitor Fixed Neutron Flux - High Function and the ATLM provides protection against reactivity transients.

2.b. <u>APRM Simulated Thermal Power - High</u>

The APRM Simulated Thermal Power - High Function monitors neutron flux to approximate the thermal power being transferred to the reactor coolant. The APRM simulated thermal power signal represents the APRM flux signal through a time constant representing the actual fuel time constant. The simulated thermal power signal accurately represents core thermal (as opposed to neutron flux) power and the heat flux through the fuel. The signal is fixed at an upper limit that is always lower than the APRM Fixed Neutron Flux - High Function Setpoint. The APRM Simulated Thermal Power - High

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Function provides protection against transients where thermal power increases slowly (such as the Loss of Feedwater Heating event) however this Function is not credited. During these events, the thermal power increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the thermal power lags the neutron flux and the APRM Fixed Neutron Flux - High Function will provide a scram signal before the APRM Simulated Thermal Power - High Function setpoint is exceeded.

Three channels of APRM Simulated Thermal Power - High Function are required to be OPERABLE to ensure no single failure will preclude a scram from this Function on a valid signal.

The Allowable Value for the APRM Simulated Thermal Power - High Function is based on the mitigation of the Loss of Feedwater Heater event, however no credit is taken for this Function.

The thermal power time constant of less than seven seconds is based on the fuel heat transfer dynamics and provides a signal proportional to the thermal power.

The APRM Simulated Thermal Power - High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive thermal power and potentially exceeding the Safety Limit applicable to high pressure and core flow conditions (fuel cladding integrity Safety Limit). During MODES 2 and 6, other SRNM and APRM Functions provide protection for fuel cladding integrity.

2.c. APRM Fixed Neutron Flux - High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. For the overpressurization protection analysis of Reference 3, the APRM Fixed Neutron Flux - High Function is assumed to terminate the MSIV Closure event and, along with the safety relief valves, limits the peak Reactor Pressure Vessel (RPV) pressure to less than the ASME Code limits. This Function is also credited in the pressure regulator failure event (Ref. 5)

Three channels of APRM Fixed Neutron Flux - High Function are required to be OPERABLE to ensure no single failure will

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

preclude a scram from this Function on a valid signal. In addition, sufficient LPRM inputs are required to be OPERABLE to provide adequate coverage of the entire core.

The Allowable Value is based on the overpressurization and pressure regulator failure event.

The APRM Fixed Neutron Flux - High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the Safety Limit (e.g., Reactor Vessel pressure) being exceeded. In MODE 2, the APRM Fixed Neutron Flux -High, Setdown Function and the SRNM trips provide adequate protection. Therefore, the APRM Fixed Neutron Flux - High Function is not required in MODE 2.

2.d. APRM - Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime a failure occurs that causes a channel to become inoperative or the APRM has too few LPRM inputs, an inoperative trip signal is automatically generated by that APRM channel, unless the APRM is bypassed.

This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

Three channels of APRM - Inop are required to be OPERABLE to ensure no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Oscillation Power Range Monitor - Upscale

The Oscillation Power Range Monitor (OPRM) consists of four channels. The OPRM channel utilizes the same set of LPRM signals used by the associated APRM channel in which this OPRM channel resides and forms many OPRM cells to monitor the neutron flux behavior of all regions of the core. The LPRM signals assigned to each cell are summed and averaged to provide an OPRM signal for this cell. The OPRM trip protection algorithms detect thermal hydraulic instability (flux oscillation with unacceptable amplitude and frequency)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and provide trip output to the RPS if the trip setpoint is exceeded.

Three channels of OPRM are required to be OPERABLE to ensure no single failure will preclude a scram from this Function on a valid signal. In addition, sufficient LPRM inputs are required to be OPERABLE to provide adequate coverage of the entire core.

There is no Allowable Value for this Function. The OPRM trip setpoints are established in accordance with the methodologies defined in Reference 6, and are documented in the Core Operating Limits Report (COLR).

The OPRM – Upscale Function is not credited in the safety analysis and is included in the Technical Specifications as a defense-in-depth feature. The OPRM – Upscale Function is provided as a backup to other RPS Functions and the Selected Control Rod Run-In/Select Rod Insert (SCRRI/SRI) function. The OPRM Function is required to be OPERABLE when THERMAL POWER is ≥ 25% RTP. The OPRM – Upscale Function is automatically enabled (bypass removed) when THERMAL POWER is ≥ 25% RTP.

ACTIONS

A Note has been provided to modify the ACTIONS related to NMS Instrumentation channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable NMS Instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided which allows separate Condition entry for each inoperable NMS Instrumentation channel.

A.1

The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of trip signals available, the redundancy of the NMS and RPS design, and the low probability of an event requiring a reactor scram during this interval. However, this out of service time is only acceptable provided the associated Function still

ACTIONS (continued)

maintains NMS actuation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the 12-hour Completion Time, the associated NMS instrument channel must be verified to be in trip. Verifying the affected NMS instrument channel in trip conservatively compensates for the inoperability and allows operation to continue.

Alternatively, if it is not desirable to verify the associated instrument channel in trip, Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

Required Action B.1 directs entry into the appropriate Condition referenced in Table 3.3.1.4-1 if the Required Action and Completion Time of Condition A is not met or if multiple, inoperable, untripped channels for the same Function result in the Function not maintaining NMS trip capability. A Function is considered to be maintaining NMS trip capability when sufficient required channels are OPERABLE or in trip (or the associated NMS division is in trip), such that two divisions will generate a trip signal from the given Function on a valid signal. For the SRNM Functions, this would require two SRNM divisions to have one channel OPERABLE or tripped (or the associated SRNM division in trip). For the APRM Functions, this would require two APRM/OPRM divisions to have one channel OPERABLE or in trip (or the associated APRM/OPRM division in trip). The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed.

C.1 and D.1

If a channel is not restored to OPERABLE status or is not in trip as required within the allowed Completion Time, or if NMS trip capability is not maintained, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems.

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ACTIONS (continued)

E.1 and E.2

If the channel(s) is not restored to OPERABLE status or is not in trip within the allowed Completion Time, or if NMS trip capability is not maintained, an alternate method to detect and suppress thermal hydraulic instability oscillations (Ref. 7) must be initiated within 12 hours and the inoperable channel(s) must be restored to OPERABLE status within 120 days.

The alternate methods would adequately address detection and mitigation in the event of thermal hydraulic instability oscillations. Based on industry operating experience with actual instability oscillations, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM system may still be available to provide alarms to the operator if the onset of oscillations were to occur.

The 12-hour Completion Time for Required Action E.1 is based on engineering judgment, considering the small probability of an instability event occurring during this interval, to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place.

The 120-day Completion Time, is considered adequate based on engineering judgment considering that with operation minimized in regions where oscillations may occur and implementation of the alternate methods, the likelihood of an instability event that could not be adequately handled by the alternate methods during this 120-day period was negligibly small.

F.1

If the channel(s) is not restored to OPERABLE status or the associated instrument channel is not in trip as required within the allowed Completion Time, or if NMS trip capability is not restored within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems.

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ACTIONS (continued)

G.1

If the channel(s) is not restored to OPERABLE status or is not in trip as required within the allowed Completion Time, or if NMS trip capability is not maintained, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the Surveillance Requirements, the SRs for each NMS instrumentation Function are located in the SRs column of Table 3.3.4.1-1.

SR 3.3.1.4.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

The NMS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is the key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication, and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECKS every 12 hours supplement less formal, but more frequent checks of channels during normal operational

BASES

SURVEILLANCE REQUIREMENTS (continued)

use of the displays associated with the channels required by the LCO.

SR 3.3.1.4.2

To ensure the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.4.5 (LPRM calibrations).

A Note is provided which only requires performance of the SR to be met at ≥ 25% RTP because it is difficult to accurately determine core THERMAL POWER from a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR). At ≥ 25% RTP, the surveillance is required to have been satisfactorily performed within the last 7 days in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7-day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. The 12 hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.4.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function when required. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the NMS DTM function.

The NMS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

As noted, for Functions 1.a, 1.b, and 2.a, SR 3.3.1.4.3 is not required to be performed when entering MODE 2 from MODE 1 because testing of the MODE 2 required SRNM and APRM Functions cannot be performed in MODE 1. This allows entry into MODE 2 if the 24-month Frequency is not met per

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Surveillance Frequency of 7 days provides an acceptable level of system average unavailability over the Surveillance Frequency interval.

SR 3.3.1.4.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the NMS DTM function.

The NMS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the channels.

SR 3.3.1.4.5

LPRM gain settings are determined from the local flux profiles measured by the automated fixed in-core probe (AFIP) subsystem of NMS. This establishes the relative local flux profile for appropriate representative input to the APRM system. The 750 MWD/T Surveillance Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.4.6

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4.6 is modified by two Notes. Note 1 states, for Functions 1.a, 1.b, and 2.a, SR 3.3.1.4.5 is not required to be performed when entering MODE 2 from MODE 1 because testing of the MODE 2 required SRNM and APRM Functions cannot be performed in MODE 1. This allows entry into MODE 2 if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. Note 2 states that neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the calorimetric calibration (SR 3.3.1.4.2) and the LPRM calibration (SR 3.3.1.4.5). The Surveillance Frequency of SR 3.3.1.4.6 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.4.7

The APRM Simulated THERMAL POWER - High Function uses time constant to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This time constant is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The time constant must be verified to ensure that the channel is accurately reflecting the desired parameter.

The 24 month Frequency is based on engineering judgment considering the reliability of the components.

SR 3.3.1.4.8

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 8. RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the SRNM channels from the sensors to the NMS Digital Trip Modules and up to each of the SRNM Trip Logic Units and the APRM and OPRM channels from the sensors (LPRMs) to the NMS Digital Trip Modules and up to each of the NMS Trip Logic Units, which house the APRM/OPRM logic. This test overlaps the testing

BASES

SURVEILLANCE REQUIREMENTS (continued)

required by SR 3.3.1.5.2 to ensure complete testing of instrument channels and actuation circuitry.

STD COL 16.0-1-A 3.3.1.4-2

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each required division are alternately tested. The 24 month test Frequency is consistent with the typical refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

SR 3.3.1.4.9

This surveillance involves confirming the OPRM - Upscale trip auto-enable setpoints. This surveillance ensures that the OPRM - Upscale trip is enabled (not bypassed) when THERMAL POWER is ≥ 25% RTP.

If any auto-enable setpoint is nonconservative (i.e., the OPRM - Upscale trip is bypassed when THERMAL POWER is ≥ 25% RTP), then the affected channel is considered inoperable for the OPRM - Upscale Function. Alternatively, the OPRM - Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in a conservative condition (not bypassed). If the OPRM - Upscale trip is placed in the not-bypassed condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

REFERENCES

1. Chapter 7, Figure 7.2-1.

2. Chapter 15

3. Subsection 5.2.2.

4. Subsection 15.3.8.

5. Subsection 15.3.4.

BASES

REFERENCES (continued)	6. Subsection 4D.3.2.2.
	7. Subsection 4D.3.3
	8. Section 15.2.

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B 3.3 INSTRUMENTATION

B 3.3.1.5 Neutron Monitoring System (NMS) Automatic Actuation

BASES

BACKGROUND

The NMS Instrumentation provides input to the Reactor Protection System (RPS) when sufficient instrumentation channels indicate a trip condition. The RPS is designed to initiate a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA).

A detailed description of the NMS instrumentation and NMS actuation logic is provided in the Bases for LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation."

This Specification addresses OPERABILITY of the NMS automatic actuation divisions that include the Startup Range Neutron Monitor (SRNM) Trip Logic Units, the Average Power Range Monitor (APRM) Trip Logic Units, which house the Oscillation Power Range Monitor (OPRM) logic, and the associated output to RPS (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"). LCO 3.3.1.4, covers SRNM and APRM (OPRM) channel inputs to the NMS Digital Trip Modules.

APPLICABLE SAFETY ANALYSES

The actions of the NMS in conjunction with RPS are assumed in the safety analyses of Reference 1. The NMS provides a trip signal to RPS when monitored parameter values exceed the trip setpoints to preserve the integrity of the fuel cladding, preserve the integrity of the reactor coolant pressure boundary, and preserve the integrity of the containment by minimizing the energy that must be absorbed following a LOCA.

NMS Automatic Actuation satisfies the requirements of Selection Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Three SRNM automatic actuation divisions and three APRM/OPRM automatic actuation divisions are required to be OPERABLE to ensure no single automatic actuation division failure will preclude a scram to occur on a valid signal. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution

BASES

LCO (continued)

Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is still met with three OPERABLE NMS actuation divisions, and because each NMS division is associated with and receives power from only one of the four electrical divisions. This Specification addresses OPERABILITY requirements of the NMS actuation circuitry that includes the interface units and the associated output to RPS.

APPLICABILITY

Three SRNM automatic actuation divisions are required to be OPERABLE in MODE 2 and in MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. In these conditions, the control rods are assumed to function during a DBA or transient and therefore the four SRNM automatic actuation channels are required to be OPERABLE. In MODES 3, 4, and 5, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. Therefore, SRNM automatic actuation is not required to be OPERABLE in these MODES.

Three APRM automatic actuation divisions are required to be OPERABLE in MODES 1 and 2. In these conditions, the control rods are assumed to function during a DBA or transient and therefore the APRM automatic actuation channels are required to be OPERABLE. In MODES 3, 4, and 5, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. Therefore, the APRM automatic actuation channels are not required to be OPERABLE in these MODES. In MODE 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the APRM automatic actuation channels are not required to support the APRM instrumentation in LCO 3.3.1.4, therefore APRM automatic actuation channels are not required to be OPERABLE in these MODES.

Three OPRM automatic actuation divisions are required to be OPERABLE when THERMAL POWER is $\geq$ 25% RTP.

ACTIONS

A Note has been provided to modify the ACTIONS related to NMS automatic actuation divisions. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the

BASES

ACTIONS (continued)

Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable NMS automatic actuation divisions provide appropriate compensatory measures for separate inoperable divisions. As such, a Note has been provided which allows separate Condition entry for each inoperable NMS automatic actuation channel.

A.1

The 12 hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide trip signals, the redundancy of the NMS and RPS design, and the low probability of event requiring a reactor scram during this interval. However, this out of service time is only acceptable provided the associated Function still maintains NMS trip capability (refer to Required Actions B.1 Bases). If the inoperable division cannot be restored to OPERABLE status within the 12-hour Completion Time, the affected actuation division must be verified to be in trip. Verifying the affected NMS actuation division in trip conservatively compensates for the inoperability and allows operation to continue.

Alternatively, if it is not desirable to verify the affected actuation division in trip (as in the case where it is desired to place the affected actuation division in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

Required Action B.1 directs entry into the appropriate Condition referenced in Table 3.3.1.5-1 if the Required Action and associated Completion Time of Condition A is not met or if multiple, inoperable, untripped divisions (i.e., two or more required divisions) for the same Function result in the Function not maintaining NMS trip capability. A Function is considered to be maintaining NMS trip capability when sufficient divisions are OPERABLE or in trip such that the NMS logic will generate a trip signal from the given Function on a valid signal. For the NMS automatic actuation divisions, two divisions must be OPERABLE or in trip to maintain NMS trip capability.

BASES

ACTIONS (continued)

The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed.

C.1 and C.2

If the channel(s) is not restored to OPERABLE status or is not in trip within the allowed Completion Time, or if NMS trip capability is not maintained, an alternate method to detect and suppress thermal hydraulic instability oscillations (Ref. 2) must be initiated within 12 hours and the inoperable channel(s) must be restored to OPERABLE status within 120 days.

The alternate methods would adequately address detection and mitigation in the event of thermal hydraulic instability oscillations. Based on industry operating experience with actual instability oscillations, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM system may still be available to provide alarms to the operator if the onset of oscillations were to occur.

The 12-hour Completion Time for Required Action C.1 is based on engineering judgment, considering the small probability of an instability event occurring during this interval, to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place.

The 120-day Completion Time for Required Action C.2 is considered adequate based on engineering judgment considering that with operation minimized in regions where oscillations may occur and implementation of the alternate methods, the likelihood of an instability event that could not be adequately handled by the alternate methods during this 120-day period was negligibly small.

D.1

If the channel(s) is not restored to OPERABLE status or the associated division is not in trip as required within the allowed Completion Time, or if NMS trip capability is not restored within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable,

BASES

ACTIONS (continued)

based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems.

E.1 and F.1

If the affected actuation division is not restored to OPERABLE status, or is not in trip, within the allowed Completion Time, or if NMS actuation capability is not maintained, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.1.5.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the NMS automatic actuation divisions. The testing in LCO 3.3.1.1, 3.3.1.2, LCO 3.3.1.4, and the functional testing of control rods in LCO 3.1.3, overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.3.1.5.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 3.

STD COL 16.0-1-A 3.3.1.5-2

RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the NMS automatic actuation divisions that include the SRNM Trip Logic Units, the APRM Trip Logic Units, which house the OPRM logic, and the associated output to RPS. This test overlaps

BASES

SURVEILLANCE REQUIREMENTS (continued)

the testing required by SR 3.3.1.4.8 to ensure complete testing of instrument channels and actuation circuitry.

RPS RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that each required division is alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 15.
2. Subsection 4D.3.3
3. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.1.6 Startup Range Neutron Monitor (SRNM) Instrumentation

BASES

BACKGROUND

The SRNMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRNM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved.

The SRNM subsystem of the Neutron Monitoring System (NMS) consists of four divisions. Each division includes three SRNMs for a total of twelve SRNMs, each having one fixed in-core regenerative fission chamber sensor. The SRNM instrumentation is discussed in detail in LCO 3.3.1.4, Neutron Monitoring System (NMS) Instrumentation." However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRNMs.

During refueling, shutdown, and low-power operations, the primary indication of neutron flux levels is provided by the SRNMs. The SRNMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low-power operation is provided by:

- LCO 3.1.1, "SHUTDOWN MARGIN (SDM);"
- LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation;
- LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation;"
- LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation;"
- LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation;" and
- LCO 3.3.2.1, "Control Rod Block Instrumentation," and
- LCO 3.9.1, "Refueling Equipment Interlocks."

BASES

APPLICABLE SAFETY ANALYSES (continued)	The monitoring requirements of the SRNMs in the Specification have no safety function and are not assumed to function during any design basis accident or transient analysis. However, the SRNMs provide the only on scale monitoring of neutron flux levels during shutdown and refueling. Therefore, they are being retained in Technical Specifications.
LCO	In MODES 3, 4, and 5, with the reactor shut down, two SRNM channels provide redundant monitoring of flux levels in the core. In MODE 6, during a spiral off-load or reload, an SRNM outside the fueled region will no longer be required to be OPERABLE, since it is not capable of monitoring neutron flux in the fueled region of the core. Thus, CORE ALTERATIONS are allowed in a quadrant with no OPERABLE SRNM in an adjacent quadrant, as provided in Table 3.3.1.6-1, footnote (a), requirement that the bundles being spiral reloaded, loaded or spiral off-loaded are all in a single fueled region containing at least one OPERABLE SRNM, is met. Spiral reloading and off-loading encompasses reloading or off-loading a cell on the edges of a continuous fueled region (the cell can be reloaded or off-loaded in any sequence). In non-spiral routine operations, two SRNMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate coverage is provided by requiring one SRNM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed and the other SRNM is to be OPERABLE in the same or adjacent quadrant. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS. For an SRNM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.
APPLICABILITY	The SRNMs are required to be OPERABLE in MODES 3, 4, 5, and 6, to provide for neutron monitoring. In MODE 2, the SRNMs are required to be OPERABLE in accordance with LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation." In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRNMs are not required.

BASES

ACTIONS

A.1 and A.2

With one or more required SRNM channels inoperable in MODE 3, 4, or 5, the neutron flux monitoring capability is degraded or it may not exist. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action and is acceptable based on engineering judgment considering the low probability of an event requiring the SRNM occurring during this interval.

B.1 and B.2

With one or more required SRNMs inoperable in MODE 6, the capability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended, and action must be immediately initiated to insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control-rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity, given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Actions (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted and the required SRNMs are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

The SRs for each SRNM Applicable MODE or other specified condition are found in the SRs column of Table 3.3.1.6-1.

SR 3.3.1.6.1 and SR 3.3.1.6.3

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred.

The NMS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The

BASES

SURVEILLANCE REQUIREMENTS (continued)

self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency of once every 12 hours for SR 3.3.1.6.1 is based on operating experience that demonstrates channel failure is rare. While in MODES 3, 4, and 5, reactivity changes are not expected; therefore, the 12-hour Frequency is relaxed to 24 hours for SR 3.3.1.6.3. The CHANNEL CHECK supplements less formal, but more frequent checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.6.2

To provide adequate coverage of potential reactivity changes in the core, one SRNM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed and the other OPERABLE SRNM must be in an adjacent quadrant. Note 1 states that this SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 6 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRNMs required OPERABLE for given CORE ALTERATIONS are in fact OPERABLE. In the event that only one SRNM is required to be OPERABLE per Table 3.3.1.6-1, footnote (a), only the part 'a' portion of this SR is required. Note 2 clarifies that the three requirements can be met by the same or different OPERABLE SRNMs. The 12-hour Surveillance Frequency is based upon operating experience and supplements operational controls over refueling activities, which include steps to ensure the SRNMs required by the LCO are in the proper quadrant.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6.4

This Surveillance consists of a verification of the plant SRNM instrument readout to ensure that the SRNM reading is greater than a specified minimum count rate. This ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRNMs will not have a high enough count rate to satisfy the Surveillance Requirement. Therefore allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note which states that the count rate is not required to be met on an SRNM that has less than or equal to four fuel assemblies adjacent to the SRNM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRNM and no other fuel assemblies in the associated quadrant, even with a control rod withdrawn, the configuration will not be critical.

The Frequency is based upon channel redundancy and other information available in the control room and ensures the required channels are frequently monitored while core reactivity changes are occurring. When no reactivity changes are in progress, the Frequency is relaxed from 12 hours to 24 hours.

SR 3.3.1.6.5 and SR 3.3.1.6.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates that the associated channel will function properly.

The NMS is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

SR 3.3.1.6.5 is required in MODE 6. The 7-day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. The 7-day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.3.1.6.6 is required in MODES 3, 4, and 5. The Frequency for CHANNEL FUNCTIONAL TESTS has been extended from 7 days to 31 days because core reactivity changes do not normally take place in MODES 3, 4, and 5. The 31-day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS. <u>SR 3.3.1.6.7</u> Performance of a CHANNEL CALIBRATION verifies the performance of the SRNM detectors and associated circuitry. The 24-month Frequency considers the unit conditions required to perform the test, the ease of performing the test, the likelihood of a change in the system or component status. The neutron detectors may be excluded from the CHANNEL CALIBRATION because they cannot readily be adjusted. The detectors are regenerative fission chambers that are designed to have a relatively constant sensitivity over the range, and with an accuracy specified for a fixed useful life.
REFERENCES	None.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, software, hardware, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the Automated Thermal Limit Monitor (ATLM) provides protection for control rod withdrawal error events. During high power operation, the Multi-Channel Rod Block Monitor (MRBM) provides protection for control rod withdrawal error events, assuming multiple failures of the ATLM. During low power operations, control rod blocks from the Rod Worth Minimizer (RWM) enforce specific control rod sequences designed to limit the consequences of a control rod withdrawal error (RWE). During shutdown conditions, control rod block from the Reactor Mode Switch - Shutdown Position ensures that all control rods remain inserted to prevent inadvertent criticalities.

The purpose of the ATLM is to limit control rod withdrawal if localized neutron flux exceeds a calculated setpoint during control rod manipulations. It is assumed to function to block further control rod withdrawal to preclude a violation of the operating limit MINIMUM CRITICAL POWER RATIO (OLMCPR), the Safety Limit MCPR (SLMCPR), and operating limit MAXIMUM LINEAR HEAT GENERATION RATE (OLMLHGR). The ATLM supplies a trip signal to the Rod Action and Position Information (RAPI) subsystem of Rod Control and Information System (RC&IS) to appropriately inhibit control rod withdrawal during power operations above the ATLM enable setpoint. There are two ATLM channels, either of which can initiate a control rod block when local neutron flux exceeds the ATLM calculated control rod block setpoint. The rod block logic circuitry in the RC&IS is arranged as two redundant and separate logic circuits. Control rod withdrawal is permitted only when the two channels agree, unless one of the channels of logic has been manually bypassed. Control rod position, Local Power Range Monitor (LPRM), and Average Power Range Monitor (APRM) data are the primary data input for the ATLM. APRM signals are used to determine when THERMAL POWER is greater than or equal to the ATLM enable setpoint to enable the ATLM rod block function (Ref. 1).

BASES

BACKGROUND (continued)

The ATLM also provides a feedwater temperature control valve one-way block and a rod withdrawal block if the reactor thermal power versus feedwater temperature combination is outside of the area allowed by the reactor power versus feedwater temperature map, or if the feedwater temperature decrease causes thermal limit violations. The ATLM provides a feedwater temperature valve one-way block and rod withdrawal block, if the feedwater temperature decreases by more than a set value from a reference feedwater temperature. The safety analyses do not credit the feedwater temperature-related blocks (Refs. 2 and 3); therefore, the feedwater temperature-related blocks of the ATLM are not required for the ATLM to be OPERABLE.

The purpose of the RWM is to ensure control rod patterns during startup are such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to just below the low power setpoint (LPSP). The sequences enforced by the RWM effectively limit the potential amount and rate of reactivity increase during a RWE.

The RWM Function of the RC&IS will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the specified sequence. The rod block logic circuitry is the same as that described above. The RC&IS also uses the APRM signals to determine when THERMAL POWER is less than or equal to the LPSP to enable the RWM rod block Function.

The purpose of the MRBM is to limit control rod withdrawal if local power changes during rod withdrawal exceed a preset rod block setpoint. It is assumed to function to block further control rod withdrawal to prevent fuel damage by ensuring that the MCPR and MLHGR do not violate fuel thermal safety limits. The MRBM supplies a trip signal to the RAPI subsystem of RC&IS to appropriately inhibit control rod withdrawal during power operations above the ATLM enable setpoint. There are two MRBM channels, either of which can initiate a control rod block when local neutron flux exceeds the rod block setpoint. The rod block logic circuitry in the RC&IS is arranged as two redundant and separate logic circuits. Control rod withdrawal is permitted only when the two channels agree, unless one of the channels of logic has been manually bypassed. Control rod position, LPRM, and APRM data are the primary data input for the MRBM. APRM signals are used to determine when THERMAL POWER is greater than or

BASES

BACKGROUND (continued)	equal to the ATLM enable setpoint to enable the MRBM rod block Function. With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents criticality resulting from inadvertent control rod withdrawal during MODE 3, 4, or 5, or during MODE 6 when the reactor mode switch is required to be in the shutdown position. A rod block in either of the two channels of RC&IS will provide a control rod block to all control rods.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	1.a. Automated Thermal Limit Monitor (ATLM) The ATLM is designed to prevent violation of the OLMCPR, the SLMCPR, and the cladding 1% plastic strain fuel design limit that may result from a RWE event. The RWE analysis during power operations is discussed in Reference 4. A statistical analysis of RWE events was performed to determine the fuel operating thermal performance response as a function of withdrawal distance and initial operating conditions. From these responses, coefficients used in the ATLM algorithms to calculate rod block setpoints were established. Each ATLM channel has two independent fuel operating thermal limit monitoring functions. One function enforces the OLMCPR, another function enforces the OLMLHGR. The rod block algorithm and setpoints of the ATLM are based on actual on line core fuel operating thermal limit information. If instantaneous LPRM data, which are fed to the ATLM, exceed the calculated rod block setpoints, a rod block signal is issued. The Automated Thermal Limit Monitor satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Two channels of the ATLM are available and are required to be OPERABLE to ensure that no single instrument failure can preclude a rod block from this Function. The OPERABILITY of the ATLM depends on the OPERABILITY of the inputs and devices required to produce a rod block. The required inputs and devices are as described in Reference 1. The ATLM is assumed to mitigate the consequences of a RWE event when THERMAL POWER is greater than or equal to the ATLM enable setpoint (≥ 30% RTP). Below this power level, the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

consequences of an RWE event will not exceed the Fuel Cladding Integrity Safety Limit (FCISL), and therefore the ATLM is not required to be OPERABLE.

1.b. Rod Worth Minimizer (RWM)

The RWM enforces the Gang Withdrawal Sequence Restrictions (GWSR) to ensure that the initial conditions of the RWE analysis are not violated. The analytical methods and assumptions used in evaluating the RWE are summarized in Reference 5. The GWSR assure that control rod worths are maintained to within reasonable values by only allowing rod patterns that result in relatively low rod worths when control rods are withdrawn. Requirements that the control rod sequence is in compliance with GWSR are specified in LCO 3.1.6, "Rod Pattern Control."

The RWM Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The RWM is a backup to operator control of control rod sequences, or reference rod pull sequence (RRPS) for automated or semi-automatic operation. However, the RWM is designed as a dual channel system and both channels are required to be OPERABLE for automatic operation. Required Actions of LCO 3.1.3, "Control Rod OPERABILITY" and LCO 3.1.6 may necessitate bypassing individual control rods in the RAPI subsystem to allow continued operation with inoperable control rods or to allow correction of a control rod pattern not in compliance with GWSR. The individual control rods may be bypassed as required by the conditions and the RWM is not considered inoperable provided SR 3.3.2.1.9 is met.

Compliance with the GWSR, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is less than or equal to the LPSP (≤ 10% RTP). Above this power level, there is no possible control rod configuration that results in a control rod worth that could exceed the 712 J/g (170 cal/g) fuel-damage limit during a RWE. In MODES 3, 4 and 5, all control rods are required to be inserted in the core. In MODE 6, since only one or two control rods associated with the same hydraulic control unit can be withdrawn from a core cell containing fuel assemblies, adequate SHUTDOWN MARGIN ensures that the consequences of a RWE are acceptable, since the reactor will be subcritical.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.c. Multi-Channel Rod Block (MRBM)

The MRBM is assumed to function to block further control rod withdrawal to prevent fuel damage by ensuring that the MCPR and MLHGR do not violate fuel thermal safety limits during an RWE conservatively assuming neither ATLM channel stops the continued withdrawal of rods. The RWE analysis during power operations is discussed in Reference 4. The MRBM logic receives inputs from the LPRMs, the APRMs, and control rod status data to determine when rod withdrawal blocks are required. The MRBM monitors the core in 4-by-4 fuel bundle regions where control rods are being withdrawn. The MRBM algorithm covers the monitoring of multiple regions simultaneously depending on the size of the gang of control rods being withdrawn. The MRBM uses the LPRM signals to detect local power changes during control rod withdrawal, and issues a block if the MRBM signal exceeds a preset rod block setpoint.

The Multi-Channel Rod Block Monitor satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Two channels of the MRBM are available and are required to be OPERABLE to ensure that no single instrument failure can preclude a rod block from this Function. The OPERABILITY of the MRBM depends on the OPERABILITY of the inputs and devices required to produce a rod block. The required inputs and devices are as described in Reference 1.

The MRBM is assumed to mitigate the consequences of a RWE event when THERMAL POWER is greater than or equal to the ATLM enable setpoint (≥ 30% RTP). Below this power level, the consequences of an RWE event will not exceed the FCISL, and therefore the MRBM is not required to be OPERABLE.

2. Reactor Mode Switch - Shutdown Position

During MODES 3, 4 and 5, and during MODE 6 when the Reactor Mode Switch is required to be in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch - Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch - Shutdown Position Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position. During shutdown conditions (MODE 3, 4, 5, or 6) no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 6 with the reactor mode switch in the refuel position and RC&IS single/gang selection switch in "single", the one rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") provides the required control rod withdrawal blocks.
ACTIONS	<u>A.1</u> With one required ATLM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the ATLM. For this reason, Required Action A.1 requires restoration of the inoperable required channel to OPERABLE status. The 7-day Completion Time for restoring ATLM to OPERABLE status is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel. <u>B.1</u> With one required RWM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RWM. For this reason, Required Action B.1 requires restoration of the inoperable required channel to OPERABLE status. The 7 day Completion Time for restoring RWM to OPERABLE status is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

BASES

ACTIONS (continued)

C.1

With one required MRBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the MRBM. For this reason, Required Action C.1 requires restoration of the inoperable required channel to OPERABLE status. The 7 day Completion Time for restoring MRBM to OPERABLE status is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

D.1

If Required Action A.1 or Required Action B.2 is not met and the associated Completion Time has expired, control rod withdrawal must be suspended immediately. In addition, if two required ATLM channels, or two required RWM channels, or two required MRBM channels are inoperable, the ATLM, or the RWM, or the MRBM is not capable of performing its intended function; thus, control rod withdrawal must also be suspended immediately. This ensures erroneous control rod withdrawal does not occur.

E.1 and E.2

With one required Reactor Mode Switch - Shutdown Position control rod withdrawal block channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod withdrawal block function. However, since the Required Actions are consistent with the normal action of an OPERABLE Reactor Mode Switch - Shutdown Position Function (i.e., maintaining all control rods inserted), there is no distinction between having one or two channels inoperable.

In both cases (one or both required channels inoperable), suspending all control rod withdrawal and initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies will ensure that the core is subcritical with adequate SDM ensured by LCO 3.1.1, "SHUTDOWN MARGIN (SDM)." Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, are not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

BASES

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the Surveillance Requirements, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a Note to indicate that a required ATLM, RWM, or MRBM channel may be placed in an inoperable status solely for performance of required Surveillances and entry into associated Conditions and Required Actions may be delayed up to 6 hours provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the required channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The allowance of this Note is based on the reliability of the channels and the average time required to perform the channel Surveillance, and the low probability of an event occurring coincident with a failure in the remaining OPERABLE channels.

<u>SR 3.3.2.1.1</u>

A CHANNEL FUNCTIONAL TEST is performed for each required ATLM channel to ensure that the entire channel will perform the intended function. It includes the RC&IS inputs. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

The Frequency of 31 days is based on the reliability of the channels.

As noted in the SR, SR 3.3.2.1.1 is not required to be performed until 1 hour after THERMAL POWER is ≥ 30% RTP. This allows THERMAL POWER to be increased to ≥ 30% RTP to perform the required Surveillance if the 31-day Frequency is not met per SR 3.0.2. The 1-hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

<u>SR 3.3.2.1.2 and SR 3.3.2.1.3</u>

A CHANNEL FUNCTIONAL TEST is performed for each required RWM channel to ensure that the entire system will perform the

SURVEILLANCE REQUIREMENTS (continued)

intended function. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

As noted in the SR, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn in MODE 2. As noted in the SR, SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP. This allows entry into MODE 2 for SR 3.3.2.1.2, and THERMAL POWER to be decreased to ≤ 10% for SR 3.3.2.1.3, to perform the required Surveillance if the 31-day Frequency is not met per SR 3.0.2. The 1-hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The Frequencies of 31 days are based on the reliability of the channels.

<u>SR 3.3.2.1.4</u>

A CHANNEL FUNCTIONAL TEST is performed for each required MRBM channel to ensure that the entire channel will perform the intended function. It includes the RC&IS inputs. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

The Frequency of 31 days is based on the reliability of the channels.

As noted in the SR, SR 3.3.2.1.4 is not required to be performed until 1 hour after THERMAL POWER is ≥ 30% RTP. This allows THERMAL POWER to be increased to ≥ 30% RTP to perform the required Surveillance if the 31-day Frequency is not met per SR 3.0.2. The 1-hour allowance is based on

BASES

SURVEILLANCE REQUIREMENTS (continued)

operating experience and in consideration of providing a reasonable time in which to complete the SRs.

SR 3.3.2.1.5

The required RWM channels are bypassed when power is above a specified value (LPSP). The power level is determined from the APRM signals. The RWM bypass setpoint must be verified periodically to be > 10% RTP (i.e., the RWM is not bypassed at or below the LPSP). If the RWM LPSP is nonconservative, then the affected RWM channel is considered inoperable. Alternatively, each required RWM channel associated with a nonconservative RWM LPSP can be placed in the conservative condition (manually enabled). If manually enabled, the SR is met and the affected RWM channel is not considered inoperable.

SR 3.3.2.1.6

The required ATLM channels are bypassed when power is below a specified value (ATLM enable setpoint). The power level is determined from the APRM signals. The ATLM bypass setpoint must be verified periodically to be < 30% RTP (i.e., the ATLM is not bypassed at or above the ATLM enable setpoint). If the ATLM enable setpoint is nonconservative, then the affected ATLM channel is considered inoperable. Alternatively, each required ATLM channel associated with a nonconservative ATLM enable setpoint can be placed in the conservative condition (manually enabled). If manually enabled, the SR is met and the affected ATLM channel is not considered inoperable.

SR 3.3.2.1.7

The required MRBM channels are bypassed when power is below a specified value (ATLM enable setpoint). The power level is determined from the APRM signals. The MRBM bypass setpoint must be verified periodically to be < 30% RTP (i.e., the MRBM is not bypassed at or above the ATLM enable setpoint). If the ATLM enable setpoint is nonconservative, then the affected MRBM channel is considered inoperable. Alternatively, each required MRBM channel associated with a nonconservative ATLM enable setpoint can be placed in the conservative condition (manually enabled). If manually enabled, the SR is met and the affected MRBM channel is not considered inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.8

The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch - Shutdown Position control rod withdrawal block is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying that a control rod block occurs.

As noted in the SR, the Surveillance is only required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads or moveable links. This allows entry into MODES 3, 4, 5, and 6 if the 24-month Frequency is not met per SR 3.0.2. The 1-hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

The 24-month Surveillance Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the surveillance when performed at the 24-month Frequency.

SR 3.3.2.1.9

LCO 3.1.3 and LCO 3.1.6 may require individual control rods to be bypassed in the RC&IS cabinets to allow insertion of an inoperable control rod or correction of a control rod pattern not in compliance with GWSR. With the control rods bypassed in the RC&IS cabinets, the RWM will not control the movement of these bypassed control rods. To ensure the proper bypassing and movement of those affected control rods, a second licensed operator or other qualified member of the technical staff must verify the bypassing and movement of these control rods. Compliance with this SR allows the RWM to be OPERABLE with these control rods bypassed.

BASES

REFERENCES

1. Subsection 7.7.2.
2. Subsection 15.2.1
3. Subsection 15.3.1.
4. Subsection 15.3.9.
5. Subsection 15.3.8.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides instrumentation and controls outside the main control room to allow prompt hot shutdown of the reactor and to maintain safe conditions during hot shutdown, which can be accomplished from either one of two remote shutdown panels. This capability is necessary to protect against the possibility of the control room becoming inaccessible. It also provides capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The operational functions needed for remote shutdown control of a system are provided on the remote shutdown panels. All parameters that can be displayed/controlled from Division 1 and Division 2 in the Main Control Room, and that are necessary to follow the status of the reactor plant, are also displayed/controlled from the corresponding divisional displays at each remote shutdown panel. The individual system equipment and instrumentation that interface with the Remote Shutdown System are listed in Reference 2. The two remote shutdown panels are located in two different areas and different rooms inside the Reactor Building.

The Remote Shutdown System provides sufficient redundancy in the control and monitoring capability to accommodate a single failure in the interfacing systems and the Remote Shutdown System controls, in addition to the single-failure event that caused the control room evacuation. The Remote Shutdown System is designed to prevent degrading the capability of the interfacing systems.

Normally, the turbine bypass valves automatically control reactor pressure, and the reactor feedwater system automatically maintains vessel water level. With these functions available, reactor cooldown is achieved through the normal heat sinks. This cooldown process can be supplemented from the remote shutdown panel using the Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System. The RWCU/SDC System provides the capability to bring the reactor from a high-pressure condition to cold shutdown. Control of both RWCU/SDC trains is provided on either remote shutdown panel. The Reactor Closed Cooling Water (RCCW) System is aligned to provide cooling water to the RWCU/SDC

BASES

BACKGROUND (continued)	non-regenerative heat exchangers, and the Plant Service Water (PSW) System is aligned to cool the RCCW heat exchangers. Control of two RCCW trains and two PSW trains is provided on either remote shutdown panel. If the reactor feedwater system is not available, control of the Control Rod Drive (CRD) System is provided on the remote shutdown panels. Control of the high-pressure makeup injection capability of the CRD System ensures that the vessel water level remains above the Automatic Depressurization System trip setpoint and above the elevation of the RWCU/SDC mid-vessel suction line nozzle. If main steam line isolation occurs, the Isolation Condenser System (ICS) automatically controls reactor pressure. Because the logic processing equipment for the ICS (or any other safety or nonsafety-related system) is outside the Main Control Room, ICS operation is not affected by an event necessitating control room evacuation, and continued operation of the isolation condensers is assured. If the event necessitating control room evacuation results in a loss of the pressure regulator, but does not cause main steam line isolation, the ICS would initiate on high pressure. With the ICS in operation, the isolation condensers provide initial decay heat removal, and further reactor cooldown is achieved from the remote shutdown panels using the RWCU/SDC. In the event that the control room becomes inaccessible, the operators can establish control at either remote shutdown panel and place and maintain the plant in MODE 3. The plant automatically reaches MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time. The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant in MODE 3, from either one of two remote shutdown panels, should the control room become inaccessible.
APPLICABLE SAFETY ANALYSES	The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to

BASES

APPLICABLE SAFETY ANALYSES (continued)	MODE 3, including the necessary instrumentation and controls to maintain the plant in a safe condition in MODE 3. The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1). The only action required to promptly shutdown the reactor to MODE 3 and maintain the plant in a safe condition in MODE 3 is a manual scram of the plant. If the operator is not able to initiate manual scram from the main control room prior to a required evacuation, manual scram can be initiated from either of the remote shutdown panels. Therefore, the Division 1 & 2 Manual Scram Switches at any one of the remote shutdown panels are required to be OPERABLE. The Remote Shutdown System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls Functions necessary to place and maintain the plant in MODE 3 from a location other than the control room. The controls and instrumentation Functions are the Reactor Protection System (RPS) Division 1 and Division 2 Manual Scram Switches. The Remote Shutdown System is OPERABLE if all instrument and control channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating," needed to support the remote shutdown function are OPERABLE for one of the two remote shutdown panels. This LCO is intended to ensure that the instruments and control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.
APPLICABILITY	The Remote Shutdown System LCO is applicable in MODES 1 and 2. This is required so that the plant can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

BASES

APPLICABILITY (continued)	This LCO is not applicable in MODES 3, 4, 5, and 6. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, TS do not require OPERABILITY in MODES 3, 4, 5, and 6.

ACTIONS

A Note has been provided to modify the ACTIONS related to Remote Shutdown System Functions. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Remote Shutdown System Functions provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable Remote Shutdown System Function.

A.1

Condition A addresses the situation where one or more required Functions is inoperable. This includes the controls for any required Function.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

If the Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1

A CHANNEL FUNCTIONAL TEST is performed on the Division 1 and Division 2 Manual Scram Switches to ensure that each switch will perform the intended Function. The Frequency of 24 months is based on the reliability of the RPS actuation logic and controls.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. Subsection 7.4.2.

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B 3.3 INSTRUMENTATION

B 3.3.3.2 Post-Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The purpose of the Post-Accident Monitoring Instrumentation is to display plant variables that provide information required by the control room operators during accident situations. The instruments that monitor these variables are designated as Type A, B, and C in accordance with Regulatory Guide 1.97 (Ref.1).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

APPLICABLE SAFETY ANALYSES

The PAM Instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A, variables. Type A variables provide the primary information required to permit the control room operating staff to:

- Take specific planned manually-controlled actions for which no automatic control is provided and that are required for safety systems to perform their safety-related functions as assumed in the plant Accident Analysis Licensing Basis.
- Take specific planned manually-controlled actions for which no automatic control is provided and that are required to mitigate the consequences of an anticipated operational occurrence.

The PAM Instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type B, variables. Type B variables are those variables that provide primary information to the control room operators to assess the plant critical safety functions.

The PAM Instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type C, variables. Type C variables are those variables that provide primary information to the control room operators to indicate the potential for breach or the actual breach of the three fission product barriers (fuel cladding, reactor coolant pressure system boundary, and containment pressure boundary).

APPLICABLE SAFETY ANALYSES (continued)

The list of Type A, B, and C PAM variables is developed and maintained in accordance with Specification 5.5.14, "Post-Accident Monitoring (PAM) Instrumentation Program."

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). PAM instrumentation that meets the definition of Type B or C in Regulatory Guide 1.97 is retained in the Technical Specifications because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Type B and C variables are important for reducing public risk.

LCO

LCO 3.3.3.2 requires two OPERABLE channels for each Type A, B, and C PAM Instrumentation Function, identified in accordance with Specification 5.5.14 and associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating," to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident. A minimum of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

APPLICABILITY

The PAM Instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate Design Basis Accidents (DBAs). The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, 5, and 6, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added to the ACTIONS Table. This Note modifies the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure,

BASES

ACTIONS (continued)

with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate Functions. As such, the Note allows separate Condition entry for each inoperable PAM Function.

A.1

When one or more required PAM Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions in accordance with Specification 5.6.5, "Post-Accident Monitoring Report," which requires a written report to be submitted to the NRC. This report discusses the cause of the inoperability and identifies proposed restorative actions. This Action is appropriate in lieu of a shutdown requirement since alternative Actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1, C.2.1, and C.2.2

Condition C applies when one or more required PAM Functions have two required channels inoperable, (i.e., two required channels inoperable in the same Function). Required Action C.1 directs restoration of one required channel to OPERABLE status. Alternatively, Required Actions C.2.1 and C.2.2 require verification that a preplanned alternate method of monitoring the affected PAM Function is available and initiation of actions in accordance with Specification 5.6.5. Required Actions C.2.1 and C.2.2 are appropriate in instances where alternate means of monitoring have been developed and tested. These alternate means may be permanently or temporarily installed and utilized if the normal PAM channel cannot be restored to OPERABLE status

ACTIONS (continued)

within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation.

D.1

If the Required Actions and associated Completion Times of Condition C cannot be met, the plant must be placed in a MODE where the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two required instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a required channel is outside the match criteria, it may be an indication that the sensor or the signal-processing equipment has drifted outside its limit. Performance of the CHANNEL CHECK guarantees that undetected channel failure is limited to 31 days.

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift,

BASES

SURVEILLANCE REQUIREMENTS (continued)

which demonstrates that failure of more than one required channel of a given function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

SR 3.3.3.2.2

A CHANNEL CALIBRATION is performed at every 24 months for each required channel. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. The Frequency is based on operating experience and consistency with the typical industry refueling cycles.

REFERENCES

1. Regulatory Guide 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," Revision 4, June 2006.

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B 3.3 INSTRUMENTATION

B 3.3.4.1 Reactor Coolant System (RCS) Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. The Bases for LCO 3.4.2, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by the drywell floor drain high conductivity waste (HCW) sump monitoring system, the drywell air cooler condensate flow monitoring, and the particulate channel of the drywell fission product monitoring system. The primary means of quantifying LEAKAGE in the drywell is the HCW sump monitoring system.

The drywell floor drain HCW sump collects unidentified leakage from such sources as floor drains, valve flanges, closed component cooling water for reactor equipment, condensate from the drywell air coolers and from any leakage not connected to the drywell equipment drain sump. The sump is equipped with two pumps and special monitoring instrumentation that measures the pump's operating frequency, the sump level and flow rates. These measurements are provided on a continuous basis to the main control room. The sump instrumentation is designed with the sensitivity to detect a leakage step-change (increase) of 3.8 liters/min (1.0 gpm) within one hour and alarm at flow rates in excess of 19 liters/min (5 gpm).

BASES

BACKGROUND (continued)	The condensate flow rate from the drywell air coolers is monitored for high drain flow, which could be indicative of leaks from piping or the equipment within the drywell. This flow is monitored by one instrumented channel using a bucket type flow transmitter located in the drywell. The flow measurement is provided to the main control room on a continuous basis for recording and alarming. Primary coolant leaks and radioactivity within the drywell are detected through sampling and monitoring of the drywell atmosphere by the Process Radiation Monitoring System (PRMS). The fission product monitor samples for radioactive particulates. The radiation levels are recorded in the main control room and alarmed on abnormally high concentration levels.
APPLICABLE SAFETY ANALYSES	A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Ref. 3). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room. A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 3). Therefore, these actions provide adequate response before a significant break in the RCPB can occur. RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).
LCO	The drywell floor drain HCW sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE. The other monitoring systems provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, leakage detection systems are required to be OPERABLE to support LCO 3.4.2. This Applicability is consistent with that for LCO 3.4.2.

ACTIONS

A.1

With the drywell floor drain HCW sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell air cooler condensate flow monitoring and the drywell fission product monitoring system will provide indications of changes in leakage. With the drywell floor drain HCW sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.2.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

B.1

With the drywell fission product monitoring system particulate channel inoperable, grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation since at least one other form of drywell leakage detection (i.e., air cooler condensate flow rate monitor) is available. The 12-hour interval provides periodic information that is adequate to detect LEAKAGE.

C.1

With the drywell air cooler condensate flow rate monitoring system inoperable, SR 3.3.4.1.1 is performed every 8 hours to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.3.4.1-1. The 8-hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leakage detection are available. However, this Required Action is modified by a Note that allows this action to be not applicable if the drywell fission product monitoring system particulate channel is inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.

BASES

ACTIONS (continued)

D.1 and D.2

With both the drywell fission product monitoring system particulate channel and the drywell air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the drywell floor drain HCW sump monitoring system. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

E.1 and E.2

If any Required Action and associated Completion Time of Condition A, B, C, or D cannot be met or if all required monitors are inoperable the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

The Frequency is based upon operating experience that demonstrates channel failure is rare.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The CHANNEL CHECKs every 12 hours supplement less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.4.1.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the required channels can perform their intended function.

The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

The Frequency of 31 days is based on instrument reliability.

SR 3.3.4.1.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. Section 5.2.5.

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B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The purpose of the ECCS instrumentation is to initiate appropriate responses from the ECCS to ensure that fuel is adequately cooled in the event of an anticipated operational occurrence or accident.

The ECCS instrumentation actuates the Automatic Depressurization System (ADS), the Gravity-Driven Cooling System (GDCS), and Standby Liquid Control (SLC). The equipment involved with ADS is described in the Bases for LCO 3.5.1, "ADS - Operating." The equipment involved with GDCS is described in the Bases for LCO 3.5.2, "GDCS - Operating." The equipment involved with SLC is described in the Bases for LCO 3.1.7, "Standby Liquid Control (SLC) System."

Technical Specifications are required by 10 CFR 50.36 to contain limiting safety system settings (LSSS) defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits,

BASES

BACKGROUND (continued)

including the requirements for determining that the channel is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least

BASES

BACKGROUND (continued)

conservative value of the as-found setpoint that a channel can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

As described in Reference 1, the Safety System Logic and Control Engineered Safety Feature (SSLC/ESF) System controls the initiation signals and logic for ECCS. SSLC/ESF is a four-division, separated protection logic system designed to provide a very high degree of assurance to both ensure ECCS initiation when required and prevent inadvertent initiation. Each division of SSLC/ESF is configured such that all functions (e.g., the digital trip module (DTM) function and voter logic unit (VLU) function) are implemented in triply redundant processors to support the requirement that single divisional failures cannot result in inadvertent actuation.

ADS, GDCS (injection and equalizing subsystems), and SLC system actuate in response to a Reactor Vessel Level - Low, Level 1.0 signal sustained for 10 seconds. Additionally, ADS and GDCS injection subsystem actuate in response to a Drywell Pressure - High signal sustained for 60 minutes.

BASES

BACKGROUND (continued)

On receipt of the trip signal the associated actuation logic will seal in and trigger the following sequence of events:

1. For only the Reactor Vessel Level - Low, Level 1.0 sustained signal, both SLC trains actuate after a time delay of 50 seconds on the first Depressurization Valve (DPV) (third ADS timer) injection signal. (The Drywell Pressure - High sustained signal does not initiate SLC trains.)

2. Five of the ten Safety Relief Valves (SRVs) open immediately to start reducing reactor pressure on the first ADS timer injection signal. The remaining five SRVs open after a 10-second time delay on the second ADS timer injection signal.

3. The eight DPVs, which are divided into four groups (group 1 consists of three DPVs, groups 2 and 3 consists of two DPVs each, and group 4 consists of one DPV) open in the following sequence: The first group opens after a 50 second time delay on the first DPV (third ADS timer) injection signal. An additional DPV group opens every 50 seconds on the second through fourth DPV (fourth through sixth ADS timer) injection signals until all of the DPVs are open.

4. All eight squib-actuated valves in the GDCS injection secondary lines open after a 150 second time delay.

5. For only the Reactor Vessel Level - Low, Level 1.0 sustained signal, all four squib-actuated valves in the GDCS equalizing lines, which connect the suppression pool to the reactor pressure vessel (RPV), actuate after a 30-minute time delay if the RPV water level is below Level 0.5. (The Drywell Pressure - High sustained signal does not initiate GDCS equalize subsystem.)

The input trip determinations for all ECCS functions are based upon two-out-of-four logic. The output trip determinations for all ECCS functions are based on the triply redundant logic in the main SSLC/ESF processors transmitting separate close signals to each of the two (for solenoid initiator) or three (for squib initiator) load driver/discrete outputs. The effect is that two of the three triply redundant processors must separately command all of the load drivers/discrete outputs to fire the divisional

BACKGROUND (continued)

initiator, making the design single failure proof against inadvertent actuation.

Four separate multiplexed instrument channels are used to monitor RPV water level for ECCS. Four separate wide range RPV water level sensors and four separate fuel zone water level sensors are utilized to provide input signals for ECCS logic. Signals from the wide range, fuel zone, and drywell pressure sensors are multiplexed at the divisional level and triply redundant sensor data is then transmitted to the SSLC/ESF triply redundant DTM function for setpoint comparison. The DTM functions make a trip/no-trip decision by comparing a digitized analog value against a setpoint and initiating a trip condition for that variable if the setpoint is exceeded. The output of each divisional DTM function (a trip/no-trip condition) is routed to all four divisional triply redundant VLU functions such that each divisional VLU function receives input from each of the four divisional DTM functions.

For maintenance purposes and added reliability, each DTM function has a division of sensors bypass such that all instruments in that division will be bypassed in the trip logic at the VLU functions. Thus, each VLU function will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time.

The processed trip signal from its own division and trip signals from the other three divisions are processed in the triply redundant divisional VLU function for two-out-of-four voting.

The load driver arrangement for actuation of an SRV, DPV squib valve, GDCS secondary branch line squib valve, and suppression pool equalizing line squib valve are given in Reference 1.

Equipment within a single division is powered from the safety-related power source of the same division.

This Specification provides the OPERABILITY requirements for the ECCS instrumentation from the input variable sensors through the DTM function. OPERABILITY requirements for the ECCS actuation circuitry consisting of timers, VLU functions, and load drivers are provided by LCO 3.3.5.2, "Emergency Core Cooling System (ECCS) Actuation." OPERABILITY requirements for actuated components (i.e.,

BASES

BACKGROUND (continued)	squibs and solenoid valves) are addressed in LCO 3.1.7, LCO 3.5.1, and LCO 3.5.2, as appropriate.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of Reference 2 and 3. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post-LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the ECCS instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. An ECCS instrumentation channel constitutes all of the components within a division of channel sensors. Each Function must have the required number of OPERABLE channels, with setpoints in accordance with the SCP, where appropriate. The actual setpoint is calibrated consistent with the SCP. Each ECCS subsystem must also respond within its assumed response time. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

$NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the actual setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but more conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS initiation to mitigate the consequences of a design basis accident or transient.

Although there are four channels of ECCS instrumentation for each function, only three ECCS instrumentation channels for each function are required to be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems-Operating," and LCO 3.8.7, "Distribution Systems -

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE ECCS instrumentation channels, and because each ECCS instrumentation division is associated with and receives power from only one of the four electrical divisions.

The specific Applicable Safety Analyses, LCO and Applicability discussions for the functions in Table 3.3.5.1-1 are listed below:

1. Reactor Vessel Water Level - Low, Level 1

Reactor Vessel Water Level - Low, Level 1 is the primary signal for the initiation of the ECCS for a steam line break outside containment because fuel damage could result if RPV water level is too low. The Reactor Vessel Water Level - Low, Level 1 is assumed to be OPERABLE and capable of initiating the ADS, GDCS (injection and equalizing subsystems), and SLC during the accidents analyzed in References 2 and 3. The core cooling function of the ECCS, along with the scram action of the RPS, assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Three channels of Reactor Vessel Water Level - Low, Level 1 Function are required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation. The Level 1 signal is initiated from four wide range level sensors.

2. Reactor Vessel Water Level - Low, Level 0.5

Reactor Vessel Water Level - Low, Level 0.5 signal is used in the ECCS logic as a permissive for actuation of the GDCS suppression equalizing lines valves, after a 30-minute time delay from the Reactor Vessel Level – Low, Level 1.0 sustained signal. The Reactor Vessel Water Level - Low, Level 0.5 is assumed to be OPERABLE and capable of initiating the GDCS suppression pool equalizing line valves following boil-off of RPV inventory during the accidents analyzed in References 2 and 3. The core cooling function of the ECCS, along with the scram action of the RPS, assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Three channels of Reactor Vessel Water Level - Low, Level 0.5 Function are required to be OPERABLE to ensure that no single instrument failure can preclude GDCS initiation. Reactor Vessel Water Level - Low, Level 0.5 signals are initiated from four fuel zone level sensors.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Drywell Pressure - High

Drywell Pressure - High is used for initiation of ADS and GDCS injection subsystem, as some steam line breaks (or breaks above operating water level), and other small breaks will not result in a level reduction to Reactor Vessel Level - Low, Level 1. This is due to the nature of steam line breaks (no rapid loss of vessel water inventory) and the large capability of the reactor feedwater system. The time delay provides sufficient margin to ensure successful event mitigation by automatic actuation.

Three channels of Drywell Pressure - High Function are required to be OPERABLE to ensure that no single instrument failure can preclude ADS and GDCS injection subsystem initiation. Drywell Pressure - High signals are initiated from four drywell pressure sensors.

The Drywell Pressure - High Function is required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the Applicability for LCO 3.6.1.1, "Containment."

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS instrumentation channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

A.1

With one or more Functions with one required channel inoperable, one instrumentation channel must be restored to OPERABLE status, such that three required channels are OPERABLE. The 12-hour Completion Time is acceptable based on engineering judgment considering the reliability of the remaining OPERABLE channels and considering that most repairs will involve only card changes or sensor replacement. However, this out of service time is only acceptable provided the associated Function still maintains

BASES

ACTIONS (continued)

ECCS actuation capability (refer to Required Actions B.1 Bases).

Alternatively, if it is not desired to restore the instrumentation channel to OPERABLE status, Condition B must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

With the Required Action and associated Completion Time of Condition A not met or if multiple, inoperable, untripped channels (i.e., two or more required channels for most Functions) for the same Function result in the Function not maintaining ECCS actuation capability, the associated feature(s) may be incapable of performing the intended function and the affected ECCS components must be declared inoperable immediately. A Function is considered to be maintaining ECCS actuation capability when sufficient channels are OPERABLE or in trip such that the ECCS logic will generate a trip signal from the given Function on a valid signal.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, The SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

SR 3.3.5.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is

SURVEILLANCE REQUIREMENTS (continued)

outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK every 12 hours supplements less formal, but more frequent checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the ECCS instrumentation channels.

SR 3.3.5.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values

BASES

SURVEILLANCE REQUIREMENTS (continued)

assumed in the accident analysis. The ECCS RESPONSE TIME acceptance criteria are included in Reference 4.

ECCS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the ECCS instrumentation from the input variable sensors through the DTM function. This test overlaps the testing required by SR 3.3.5.2.2 to ensure complete testing of instrument channels and actuation circuitry.

STD COL 16.0-1-A 3.3.5.1-2

ECCS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the required channels associated with each division are alternately tested.

The 24-month test Frequency is consistent with the typical industry refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 7.

2. Chapter 15.

3. Chapter 6.

4. Section 15.2.

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B 3.3 INSTRUMENTATION

B 3.3.5.2 EMERGENCY CORE COOLING SYSTEM (ECCS) ACTUATION

BASES

BACKGROUND

The purpose of the ECCS actuation logic is to initiate appropriate responses from the ECCS to ensure that fuel is adequately cooled in the event of a design basis event.

The ECCS logic actuates the Automatic Depressurization System (ADS), the Gravity-Driven Cooling System (GDCS), the Isolation Condenser System, and Standby Liquid Control (SLC). The equipment involved with ADS is described in the Bases for LCO 3.5.1, "ADS - Operating." The equipment involved with GDCS is described in the Bases for LCO 3.5.2, "Gravity-Driven Cooling System (GDCS) - Operating." The equipment involved with SLC is described in the Bases for LCO 3.1.7, "Standby Liquid Control (SLC) System."

A detailed description of the ECCS instrumentation and ECCS actuation logic is provided in the Bases for LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation."

This specification addresses OPERABILITY of the ECCS actuation circuitry from the outputs of the Digital Trip Module (DTM) through the voter logic unit (VLU) functions, the timers and the load drivers (LDs) associated with the ADS safety relief valves (SRVs), the ADS depressurization valves (DPVs), the GDCS injection valves, the GDCS equalizing line valves, and the SLC squib-actuated valves. Operability requirements associated with the ECCS instrumentation channels are provided in LCO 3.3.5.1. Operability requirements for actuated components (i.e., squibs and solenoid valves) are addressed in LCO 3.1.7, LCO 3.5.1, and LCO 3.5.2, as appropriate.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of Reference 1 and 2. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post-LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS Actuation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ECCS actuation supports OPERABILITY of the ECCS Instrumentation, "LCO 3.3.5.1, Emergency Core Cooling System (ECCS) Instrumentation" and therefore is required to be OPERABLE. This Specification addresses OPERABILITY of the ECCS actuation circuitry from the outputs of the DTM functions through the VLU functions, the timers, and the LDs associated with the ADS safety relief valves (SRVs), the ADS depressurization valves (DPVs), the GDCS injection valves, the GDCS equalizing line valves, and the SLC squib-actuated valves.

Although there are four divisions of ECCS actuation for each function, only three ECCS actuation divisions for each function are required to be OPERABLE. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE ECCS actuation divisions, and because each ECCS actuation division is associated with and receives power from only one of the four electrical divisions.

1. Automatic Depressurization System (ADS)

The ADS actuation divisions receive input from the Reactor Vessel Level - Low, Level 1.0 signal sustained for 10 seconds, or from the Drywell Pressure - High signal sustained for 60 minutes. ADS actuation is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the requirements of LCO 3.5.1, "Automatic Depressurization System (ADS) - Operating." ADS actuation is required to be OPERABLE in MODE 5, and in MODE 6 prior to removal of the reactor pressure vessel head, consistent with the requirements of LCO 3.5.3, "Gravity-Driven Cooling System (GDCS) – Shutdown." Three actuation divisions are required to be OPERABLE to ensure that no single actuation failure can preclude the actuation function.

2. Gravity-Driven Cooling System (GDCS) Injection Lines

The GDCS injection line actuation divisions receive input from the Reactor Vessel Level - Low, Level 1.0 signal sustained for 10 seconds, or from the Drywell Pressure - High signal sustained for 60 minutes. GDCS injection line actuation is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the requirements of LCO 3.5.2, "Gravity-Driven Cooling System (GDCS) - Operating." GDCS

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

injection line actuation is required to be OPERABLE in MODES 5 and 6, except with the buffer pool gate removed and water level ≥ 7.01 meters (23.0 feet) over the top of the reactor pressure vessel flange, consistent with the requirements of LCO 3.5.3, "Gravity-Driven Cooling System (GDCS) - Shutdown." Three actuation divisions are required to be OPERABLE to ensure that no single actuation failure can preclude the actuation function.

3. GDCS Equalizing Lines

The GDCS equalizing line actuation divisions receive input from the following instrumentation: Reactor Vessel Level - Low, Level 1.0 signal sustained for 10 seconds and Reactor Vessel Level - Low, Level 0.5. GDCS equalizing line actuation is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the requirements of LCO 3.5.2, "Gravity-Driven Cooling System (GDCS) - Operating." GDCS equalizing line actuation is required to be OPERABLE in MODES 5 and 6, except with the buffer pool gate removed and water level ≥ 7.01 meters (23.0 feet) over the top of the reactor pressure vessel flange, consistent with the requirements of LCO 3.5.3, "Gravity-Driven Cooling System (GDCS) - Shutdown." Three actuation divisions are required to be OPERABLE to ensure that no single actuation failure can preclude that actuation function.

4. Standby Liquid Control (SLC)

The SLC actuation divisions receive inputs from the Reactor Vessel Level - Low, Level 1.0 signal sustained for 10 seconds. SLC actuation is required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the requirements of LCO 3.1.7, "Standby Liquid Control (SLC) System." Three actuation divisions are required to be OPERABLE to ensure that no single actuation failure can preclude that actuation function.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS divisions of actuation logic. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the

BASES

ACTIONS (continued)

Condition. However, the Required Actions for inoperable ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable division of ECCS actuation logic.

A.1

Condition A exists when one required ECCS actuation division is inoperable. In this Condition, ECCS actuation still maintains actuation trip capability, but cannot accommodate a single failure. The 12 hour Completion Time is acceptable based on engineering judgment considering the reliability of the remaining OPERABLE channels and considering that most repairs will involve only card changes or sensor replacement. However, this out of service time is only acceptable provided the associated Function still maintains ECCS actuation capability (refer to Required Actions B.1 Bases).

B.1

If the Required Actions and associated Completion Times of Condition A are not met or two or more required actuation divisions are inoperable, the affected actuation device(s) must be declared inoperable immediately. In this Condition, a loss of ECCS actuation capability occurs to numerous ECCS actuation devices. ECCS automatic actuation capability is considered to be maintained when sufficient actuation divisions are OPERABLE or in trip such that the ECCS logic will generate an actuation signal on a valid signal.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required ECCS logic for a specific division.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The ECCS RESPONSE TIME acceptance criteria are included in Reference 3.

ECCS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total division measurements. This test encompasses the ECCS actuation circuitry from the outputs of the DTM functions through the VLU functions, the timers, and the LDs associated with the ADS SRVs, the ADS DPVs, the GDCS injection valves, the GDCS equalizing line valves, and the SLC squib-actuated valves. This test overlaps the testing required by SR 3.3.5.1.4 to ensure complete testing of instrument channels and actuation circuitry.

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ECCS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that each required division is alternately tested.

The 24 month test Frequency is consistent with the typical industry refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 15.

2. Chapter 6.

3. Section 15.2.

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B 3.3 INSTRUMENTATION

B 3.3.5.3 Isolation Condenser System (ICS) Instrumentation

BASES

BACKGROUND

The purpose of the ICS instrumentation is to initiate appropriate actions to ensure ICS operates following a reactor pressure vessel (RPV) isolation after a scram to provide adequate RPV pressure reduction to preclude safety relief valve operation, conserve RPV water level to avoid automatic depressurization caused by low water level. In addition, in the event of a loss of coolant accident (LOCA), the ICS instrumentation ensures the system operates to provide liquid inventory to the RPV. The ICS instrumentation also ensures the ICS is vented to mitigate the accumulation of radiolytic hydrogen and oxygen in order to prevent a detonation. The equipment involved with ICS is described in the Bases for LCO 3.5.4, "Isolation Condenser System (ICS) - Operating."

Technical Specifications are required by 10 CFR 50.36 to contain limiting safety system settings (LSSS) defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits,

BASES

BACKGROUND (continued)

including the requirements for determining that the channel is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least conservative value of the as-found setpoint that a channel

BASES

BACKGROUND (continued)

can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The ICS can be automatically or manually initiated. The ICS actuates automatically in response to signals from any of the following:

1. Reactor Steam Dome Pressure - High for 10 seconds,

2. RPV Water Level - Low (Level 2), with time delay,

3. RPV Water Level - Low (Level 1),

4. Indication that two Main Steam Isolation Valves (MSIVs) in separate Main Steamlines (MSLs) are not fully open with the reactor mode switch in the run position, or

5. Loss of power generation buses.

BASES

BACKGROUND (continued)

ICS venting can be automatically or manually initiated. ICS venting actuates automatically, following a 6-hour time delay, in response to a signal that at least one Condensate Return Valve (i.e. the condensate return valve or the condensate return bypass valve) for a given ICS train has opened.

The Safety System Logic and Control Engineered Safety Features (SSLC/ESF) System controls the initiation signals and logic for ICS. SSLC/ESF is a four division, separated protection logic system designed to provide a very high degree of assurance to both ensure ICS initiation when required and prevent inadvertent initiation. The input and output trip determinations for all ICS functions are based upon a two-out-of-four logic arrangement. Each division of SSLC/ESF is configured such that all functions (e.g., the digital trip module (DTM) function and voter logic unit (VLU) function) are implemented in triply redundant processors to support the requirement that single divisional failures cannot result in inadvertent actuation.

Four separate instrument channels are used to monitor ICS initiation parameters. Signals from sensors are multiplexed at the divisional level and the triply redundant sensor data is then transmitted to the SSLC/ESF triply redundant digital trip module (DTM) function for setpoint comparison. The output of each divisional DTM function (a trip/no-trip condition) is routed to all four divisional triply redundant VLU functions such that each divisional VLU function receives input from each of the four divisional DTM functions.

For maintenance purposes and added reliability, each DTM function has a division of sensors bypass such that all instruments in that division will be bypassed in the trip logic at the VLU functions. Thus, each VLU function will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time.

The processed trip signal from its own division and trip signals from the other three divisions are processed in the triply redundant VLU function for two-out-of-four voting.

The load driver arrangement for actuation of the ICS Condensate Return Valves are such that an actuation signal from two divisions of ICS actuation logic are required to actuate a condensate return flow path.

BASES

BACKGROUND (continued)	Equipment within a single division is powered from the safety-related power source of the same division. This Specification provides Operability requirements for the ICS instrumentation from the input variable sensors through the DTM function. Operability requirements for the ICS actuation circuitry consisting of timers, VLU functions, and load drivers are provided by LCO 3.3.5.4, "Isolation Condenser System (ICS) Actuation." Operability requirements for the actuated components are addressed in LCO 3.5.4.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The actions of the ICS are explicitly assumed in the safety analyses of Reference 1. The ICS is initiated to preserve the integrity of the fuel cladding by limiting the post-LOCA peak cladding temperature to less than the 10 CFR 50.46 limits. Actuation of the ICS precludes actuation of safety relief valves and limits the peak RPV pressure to less than the ASME Section III Code limits. The ICS Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). The OPERABILITY of the ICS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.3-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate. The actual setpoint is calibrated consistent with the SCP. Each channel must also respond within its assumed response time. $NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the actual setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value. The individual Functions are required to be OPERABLE in the MODES specified in the Table which may require an ICS actuation to mitigate the consequences of a design basis accident or transient. Although there are four channels of ICS instrumentation for each function, only three ICS instrumentation channels for

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

each function are required to be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems -Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE ICS instrumentation channels, and because each ICS instrumentation division is associated with and receives power from only one of the four electrical divisions.

The specific Applicable Safety Analyses, LCO and Applicability discussions are listed below on a Function-by-Function basis.

1. Reactor Vessel Steam Dome Pressure - High

ICS is designed to operate following reactor pressure vessel (RPV) isolation to provide adequate RPV pressure reduction to preclude safety relief valve operation and provide core cooling while conserving reactor water inventory. Therefore, Reactor Vessel Steam Dome Pressure - High Function existing for 10 seconds initiates an ICS actuation for transients that result in a pressure increase. Actuation of the ICS provides RPV pressure reduction to preclude safety relief valve operation and provide core cooling.

High reactor pressure signals are initiated from four pressure sensors that sense reactor pressure. The Reactor Vessel Steam Dome Pressure - High Allowable Value provides a sufficient margin to the ASME Section III Code limits during the event.

Three channels of Reactor Vessel Steam Dome Pressure - High Function are required to be OPERABLE to ensure no single instrument failure will preclude ICS actuation.

The Function is required to be OPERABLE in MODES 1, 2, 3, 4, and 5.

2. Reactor Vessel Water Level - Low, Level 2

Low reactor vessel water level indicates the capability to cool the fuel may be threatened. Should reactor vessel water level decrease too far, fuel damage could result. Therefore, an ICS actuation is initiated at Level 2, with a 30-second time delay to provide a source of core cooling. The time delay provides an allowance for temporary transients that

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

may reduce RPV level below the Level 2 setpoint. This Function is assumed to be available to support the transient and design basis analyses (Ref. 1).

Reactor Vessel Water Level - Low, Level 2, signals are initiated from four wide range level sensors.

Three channels of Reactor Vessel Water Level Low, Level 2, Function are required to be OPERABLE to ensure no single instrument failure will prevent ICS actuation from this Function on a valid signal.

The Function is required to be OPERABLE in MODES 1, 2, 3, 4, and 5.

3. Reactor Vessel Water Level - Low, Level 1

Low Reactor Vessel Water Level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ICS receives the signals necessary for initiation from this Function. The Reactor Vessel Water Level - Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of actuating the ICS during the accidents analyzed in Reference 1. The core cooling function of the ICS along with the ECCS and the scram action of the RPS, assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low, Level 1 signals are initiated from four wide range level sensors.

Three channels of Reactor Vessel Water Level - Low, Level 1 Function are required to be OPERABLE when ICS is required to be OPERABLE to ensure that no single instrument failure can preclude ICS actuation, when required.

The Function is required to be OPERABLE in MODES 1, 2, 3, 4, and 5.

4. Main Steam Isolation Valve - Closure

Main Steam Isolation Valve (MSIV) closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to isolate the reactor to reduce excessive steam line flow or leakage outside the containment. Therefore, an ICS actuation is initiated on an MSIV closure signal before the MSIVs are

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. MSIV closure is assumed in the transients and accidents analyzed in Reference 1. The ICS actuation, along with the reactor scram, assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The logic for the Main Steam Isolation Valve - Closure Function is arranged such that ICS initiation occurs if two MSIVs in separate MSLs are not fully open with the Reactor Mode Switch in run.

The MSIV - Closure Allowable Value is specified to ensure that an ICS initiation occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

Three channels of MSIV - Closure Function are required to be OPERABLE to ensure no single instrument failure will prevent the ICS actuation from this Function on a valid signal. This Function is only required in MODE 1 because with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close.

5. Power Generation Bus Loss

The plant electrical system has four redundant power generation buses that operate at 13.8 kV. These buses supply power for the feedwater pumps and other pumps. In MODE 1, at least three of the four buses must be powered. The purpose of ICS initiation on losing feedwater flow is to provide a source of core cooling following the loss of feedwater pump function.

The Allowable Value was selected high enough to detect a loss of voltage in order to mitigate the reactor water level drop to Level 1 following the loss of feedwater pump function.

Three channels of Power Generation Bus Loss Function are required to be OPERABLE to ensure that no single instrument failure will prevent the ICS actuation from this Function on a valid signal. The Function is required in MODE 1 where considerable energy exists in the reactor coolant system resulting in the limiting transients and accidents. During MODES 2, 3, 4, 5, and 6, the core energy is significantly lower.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Condensate Return Valve – Open (per Isolation Condenser)

When an ICS initiation signals occurs, the condensate return valve and condensate return bypass valve for each ICS train open, which starts isolation condenser operation. After a six-hour time delay following either condensate return valve opening, the lower header vent valves automatically open to prevent the accumulation of radiolytically generated hydrogen and oxygen.

The logic for the Condensate Return Valve – Open Function is arranged such that the SSLC/ESF-actuated ICS vent valve will open upon opening of either of the condensate return valves on the associated ICS train.

Condensate Return Valve – Open signals are initiated from four position switches located on each condensate return and condensate return bypass valve.

Three channels of the Condensate Return Valve - Open Function for each Condensate Return Valve on each ICS train are required to be OPERABLE when ICS is required to be OPERABLE to ensure that no single instrument failure can preclude ICS vent actuation, when required.

The Function is required to be OPERABLE in MODES 1, 2, 3, 4, and 5.

ACTIONS

The ACTIONS have been modified by a Note to permit separate Condition entry for each ICS instrumentation channel. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ICS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ICS instrumentation channel.

A.1

With one or more Functions with one required channel inoperable, the affected required channel must be restored

BASES

ACTIONS (continued)

to OPERABLE status within 12 hours. The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide actuation signals, the redundancy of the ICS instrumentation design, and the low probability of an event requiring ICS actuation during this period.

However, this out of service time is only acceptable provided the associated Function still maintains ICS actuation capability (refer to Required Actions B.1 Bases).

Alternatively, if the instrumentation channel can not be restored to OPERABLE status, Condition B must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

With the Required Action and associated Completion Time of Condition A not met or if multiple, untripped required channels (i.e., two or more required channels for most Functions) for the same Function result in the Function not maintaining ICS actuation capability, the associated feature(s) may be incapable of performing the intended function and the ICS trains must be declared inoperable immediately. A Function is considered to be maintaining ICS actuation capability when sufficient channels are OPERABLE or in trip such that the ICS logic will generate an initiation signal from the given Function on a valid signal.

SURVEILLANCE REQUIREMENTS

The Surveillance Requirements are modified by a Note. The Note directs the reader to Table 3.3.5.3-1 to determine the correct SRs to perform for each ICS Instrumentation Function.

SR 3.3.5.3.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

BASES

SURVEILLANCE REQUIREMENTS (continued)

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK every 12 hours supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the channels.

SR 3.3.5.3.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.3.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The ICS RESPONSE TIME acceptance criteria are included in Reference 2.

ICS RESPONSE TIME may be verified by actual response time measurements or any series of sequential, overlapping, or total channel measurements. This test encompasses the ICS instrumentation from the input variable sensors through the DTM function. This test overlaps the testing required by SR 3.3.5.4.2 to ensure complete testing of instrumentation channels and actuation circuitry.

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ICS SYSTEM RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that each required channel is alternately tested. The 24-month test Frequency is consistent with the typical refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 15.
2. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.5.4 Isolation Condenser System (ICS) Actuation

BASES

BACKGROUND	The purpose of the ICS actuation logic is to initiate appropriate actions to ensure ICS operates following a reactor pressure vessel (RPV) isolation after a scram to provide adequate RPV pressure reduction to preclude safety relief valve operation and to conserve RPV water level to avoid automatic depressurization caused by low water level. In addition, in the event of a loss of coolant accident (LOCA), the ICS instrumentation ensures the system operates to provide additional liquid inventory to the RPV upon opening of the condensate return valves. The ICS actuation logic also ensures the ICS is vented to mitigate the accumulation of radiolytic hydrogen and oxygen in order to prevent a detonation. A detailed description of the ICS actuation instrumentation is provided in the Bases for LCO 3.3.5.3, "Isolation Condenser System (ICS) Instrumentation." This specification addresses OPERABILITY of the ICS actuation circuitry from the outputs of the Digital Trip Module (DTM) functions through the voter logic unit (VLU) functions, the timers and the load drivers (LDs) associated with the ICS. Operability requirements associated with ICS instrumentation channels are provided in LCO 3.3.5.3. Operability requirements for actuated components are addressed in LCO 3.5.4, "Isolation Condenser System (ICS) - Operating."
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The actions of the ICS are explicitly assumed in the safety analyses of Reference 1. The ICS is initiated to preserve the integrity of the fuel cladding by limiting the post-LOCA peak cladding temperature to less than the 10 CFR 50.46 limits. Actuation of the ICS also, precludes actuation of safety relief valves and limits the peak RPV pressure to less than the ASME Section III Code limits. ICS actuation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Although there are four divisions of ICS actuation, only three ICS actuation divisions for each function are required to be OPERABLE. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE ICS instrumentation divisions, and because each ICS instrumentation division is associated with and receives power from only one of the four electrical divisions.

1. <u>ICS Initiation Actuation</u>

The ICS Initiation Actuation logic is the logic associated with automatically placing the ICS into service.

The ICS Initiation Actuation divisions receive input from the following:

- Reactor Steam Dome Pressure - High for 10 seconds,
- RPV Water Level - Low (Level 2), with time delay,
- RPV Water Level - Low (Level 1),
- Indication that two Main Steam Isolation Valves (MSIVs) in separate Main Steamlines (MSLs) are not fully open with the reactor mode switch in the run position, or
- Loss of power generation buses.

The ICS Initiation Actuation is required to be OPERABLE in MODES 1, 2, 3, 4, and 5, to preclude actuation of safety relief valves and limit the peak RPV pressure to less than the ASME Section III Code limits. Additionally, ICS Initiation Actuation assists in preserving the integrity of the fuel cladding by limiting the post-LOCA peak cladding temperature to less than the 10 CFR 50.46 limits, and removing reactor decay heat following reactor shutdown and isolation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. ICS Vent Actuation

The ICS Vent Actuation divisions receive input from the Condensate Return Valve Position – Open signals for each Condensate Return Valve. The logic is arranged such that if either Condensate Return Valve is open for an ICS train, then its vent will open after a 6-hour time delay.

The ICS Vent Actuation is required to be OPERABLE in MODES 1,2,3,4, and 5 to support proper operation of the ICS and to mitigate the accumulation of radiolytic hydrogen and oxygen that could cause a detonation.

ACTIONS

A.1

Condition A exists when one required ICS actuation division is inoperable. In this Condition, ICS actuation still maintains actuation trip capability but can not accommodate a single failure. The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide trip signals, the redundancy of the ICS actuation design, and the low probability of an event requiring ICS actuation during this period. However, this out of service time is only acceptable provided the associated Function still maintains ICS actuation capability (refer to Required Actions B.1 Bases).

B.1

With the Required Action and associated Completion Time of Condition A not met or if two or more required actuation divisions are inoperable, the affected ICS actuation device(s) must be declared inoperable immediately. ICS automatic actuation capability is considered to be maintained when sufficient actuation divisions are OPERABLE or in trip such that the ICS logic will generate an actuation signal on a valid signal.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the Surveillance Requirements, the SRs for each ICS Actuation Function are located in the SRs column of Table 3.3.5.4-1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.4.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required ICS logic for a specific division.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.5.4.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The ICS RESPONSE TIME acceptance criteria are included in Reference 2.

ICS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total division measurements. This test encompasses the ICS actuation circuitry from the outputs of the DTM function through the VLU function, the timers and the LDs associated with the ICS. This test overlaps the testing required by SR 3.3.5.3.4 to ensure complete testing of instrument channels and actuation circuitry.

STD COL 16.0-1-A 3.3.5.4-1

ICS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that each required division is alternately tested.

The 24-month test Frequency is consistent with the typical industry refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Chapter 15.
2. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Main Steam Isolation Valve (MSIV) Instrumentation

BASES

BACKGROUND

The isolation instrumentation contained in this specification provides the capability to generate isolation signals to the MSIVs and main steamline (MSL) drain isolation valves. The function of the MSIVs and MSL drain isolation valves, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs).

Technical Specifications are required by 10 CFR 50.36 to contain limiting safety system settings (LSSS) defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits, including the requirements for determining that the channel is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

BASES

BACKGROUND (continued)

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least conservative value of the as-found setpoint that a channel can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

BACKGROUND (continued)

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The MSIV Isolation circuitry, as shown in Reference 1, is divided into four redundant divisions of sensor (instrument) channels, four trip logics, and the hard-wired MSIV solenoid logic circuitry. The MSIV Isolation circuitry is contained in the Reactor Trip and Isolation Function (RTIF) portion of the Safety-Related Distributed Control and Information System (Q-DCIS) along with the Reactor Protection System (RPS). Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the MSIV logic are from instrumentation that monitors reactor vessel water level (Level 1 and Level 2), main steam line pressure, main steam line flow, condenser pressure, main steam tunnel ambient temperature, and main steam turbine area ambient temperature. The plant parameters that are required to be monitored for MSIV logic are each measured independently by four sensors. Each sensor is assigned to one of the four redundant instrument channels, which are in turn associated with four divisions of logic. For any monitored parameter, the sensor signals of at least two of the four redundant instrument channels must exceed a predetermined setpoint value for trip to occur in a division of logic.

BASES

BACKGROUND (continued)

Each MSIV Isolation division has a Remote Multiplexer Unit (RMU) function, a Digital Trip Module (DTM) function, a Trip Logic Unit (TLU) function, and the Output Logic Unit (OLU) function. The RMU receives input from the sensor devices and performs analog-to-digital conversion and signal processing functions. The digitized signal is then sent to the DTM. The DTM generates the trip signal based on setpoint comparison. Each DTM sends a separate trip/no trip output signal to the TLUs in the four divisions of trip logic. Each TLU performs the two-out-of-four logic function to determine the trip status for each of the four divisions.

For maintenance purposes and added reliability, each TLU receives a division of sensors bypass such that all instruments in that division can be bypassed in the trip logic at the TLU. Thus, each TLU will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time.

The two-out-of-four trip logic decision (or two-out-of-three if a division of sensors bypass is in effect) is made by each TLU on a per variable basis such that setpoint exceedence in two instrument divisions for the same variable is required to initiate a trip output at the TLU. Since each TLU sees the outputs from all four DTMs, all four divisions of logic should sense and initiate a required trip simultaneously. A two-out-of-four trip in a TLU causes a trip in its corresponding OLU. It is this trip that then initiates an isolation by tripping load drivers in the power circuits that energize the MSIV solenoids. Each OLU sends output signals to load drivers associated with the MSIV solenoids and MSL drain isolation valves. The overall arrangement of OLU outputs and load driver groupings is such that a trip of any two of four TLUs (and associated OLUs) will result in full isolation of all MSLs. Each of the four TLUs has a division of logic bypass switch so that they can be bypassed, only one at any one time, such that the MSIV output logic reverts to two-out-of-three, i.e., the tripping of any two of the three remaining TLUs will still result in a full MSIV isolation. However, with this bypass in effect, the OLU for the division can be manually actuated at the OLU. Each OLU has test and trip switches such that the load drivers can be tested both with and without causing a full isolation condition.

Equipment within a single division is powered from the safety-related power source of the same division.

BASES

BACKGROUND (continued)	This Specification provides the OPERABILITY requirements for the MSIV isolation instrumentation from the input variable sensors through the DTM digital trip function. Operability requirements for the MSIV isolation actuation circuitry consisting of the TLU two-out-of-four function, timers, OLUs, and load drivers are provided by LCO 3.3.6.2, "Main Steam Isolation Valve (MSIV) Actuation." Operability requirements for actuated components (i.e., MSIV solenoid valves) are addressed in LCO 3.6.1.3, "Containment Isolation Valves (CIVs)."

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the MSIV instrumentation are assumed in the safety analyses of References 2 and 3 to initiate closure of the MSIVs and MSL drain isolation valves to limit offsite doses. Refer to LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," Applicable Safety Analyses Bases, for more detail on MSIV isolation.

MSIV isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). However, certain monitored instrumentation parameters are retained for other reasons and are described below in the individual process parameter discussion.

The OPERABILITY of the MSIV isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate. Each channel must also respond within its assumed response time, where appropriate.

$NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

In general, the individual monitored process parameters are required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the Applicability of LCO 3.6.1.3. Functions that have

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

different Applicabilities are discussed below in the individual Functions discussion.

Although there are four channels of MSIV instrumentation for each function, only three channels of MSIV instrumentation for each function are required to be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems -Operating." This is acceptable because the single-failure criterion is met with three OPERABLE MSIV instrumentation channels, and because each MSIV instrumentation division is associated with and receives power from only one of the four electrical divisions.

The specific Applicable Safety Analyses, LCO and specific Applicability discussions are provided below on a Function basis.

1. Reactor Vessel Water Level - Low, Level 2

Low reactor pressure vessel (RPV) water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The isolations of the MSIVs and MSL drain isolation valves limit the release of fission products to help ensure that offsite does limits are not exceeded. The Reactor Vessel Water Level - Low, Level 2 is explicitly credited in the LOCA inside containment radiological analysis (Ref. 4).

Reactor Vessel Water Level - Low, Level 2 signals are initiated from four level sensors that sense the difference between the pressure due to a constant column (reference leg) of water and the pressure due to the actual water level (variable leg) in the vessel. Three channels of Reactor Vessel Water Level - Low, Level 2 Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low, Level 2 Allowable Value was chosen to be the same as the Isolation Condenser System Reactor Vessel Water Level - Low, Level 2 Allowable Value.

2. Reactor Vessel Water Level - Low, Level 1

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far,

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

fuel damage could result. The isolations of the MSIVs and MSL drain isolation valves limit the release of fission products to help ensure that offsite does limits are not exceeded. The Reactor Vessel Water Level - Low, Level 1 channels are provided as a backup to the Reactor Vessel Water Level - Low, Level 2 channels and are not credited in the safety analysis.

Reactor Vessel Water Level - Low, Level 1 signals are initiated from four level sensors that sense the difference between the pressure due to a constant column (reference leg) of water and the pressure due to the actual water level (variable leg) in the vessel. Three channels of Reactor Vessel Water Level - Low, Level 1 Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low, Level 1 Allowable Value was chosen to be the same as the Automatic Depressurization Reactor Vessel Water Level - Low, Level 1 Allowable Value.

3. Main Steam Line Pressure - Low

Low main steam line pressure indicates that there may be a problem with the turbine pressure regulation that could result in the Reactor Pressure Vessel (RPV) cooling down more than 55.6°C/hr (100°F/hr) if the pressure loss is allowed to continue. The Main Steam Line Pressure - Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 5). For this event the closure of the MSIVs and MSL drain isolation valves ensures that the RPV temperature change limit 55.6°C/hr (100°F/hr) is not reached.

The main steam line low-pressure signals are initiated from four sensors that sense the pressure downstream of the outboard MSIVs. The sensors are arranged such that, even though physically separated from each other, each sensor is able to detect low main steam line pressure. Three channels of Main Steam Line Pressure - Low Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function. The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Main Steam Line Pressure - Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 5).

4. <u>Main Steam Line Flow - High (per Steam Line)</u>

Main Steam Line Flow - High is provided to detect a break of the main steam line (MSL) and to initiate closure of the MSIVs and MSL drain isolation valves. If the steam were allowed to continue flowing out the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow - High Function is directly assumed in the analysis of the MSL break (Ref. 6). The isolation action, along with the scram function of the RPS and the operation of the ECCS and Safety Relief Valves assures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite dose limits.

The MSL flow signals are initiated from 16 differential pressure sensors that are connected to the four MSLs, four per steam line. The differential pressure sensors are arranged such that, even though physically separated from each other, all four connected to one MSL would be able to detect the high flow in that steam line. High MSL flow in any steam line will result in isolation of all MSLs. Three channels of Main Steam Line Flow - High Function for each main steam line are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual main steam line.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

5. <u>Condenser Pressure - High (per condenser)</u>

The Condenser Pressure - High Function is provided to prevent overpressurization of the main condenser in the event of a loss of main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Pressure - High Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs and MSL drain isolation valves is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident. The Condenser Pressure - High Function is credited in the transients in References 7 and 8.

Condenser pressure signals are derived from four pressure sensors that sense the pressure in the condenser. Three channels of Condenser Pressure - High Function (per condenser) are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis.

The Condenser Pressure – High Function is required to be OPERABLE in MODE 1. This Function is bypassed when the Reactor Mode Switch is not in the Run position.

6, 7. Main Steam Tunnel and Turbine Area Ambient Temperature - High

Main Steam Tunnel and Turbine Area Ambient Temperature - High Functions are provided to detect a leak in the reactor coolant pressure boundary and provide diversity to the MSL high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis because bounding analyses are performed for large breaks such as a MSL break.

Ambient temperature signals are initiated from thermocouples located away from the main steam lines so they are only sensitive to ambient air temperature. Three channels of Main Steam Tunnel Temperature - High Function are available and required to be OPERABLE to ensure no single instrument failure can preclude the isolation function. Three channels of Turbine Area Ambient Temperature - High Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The ambient temperature monitoring Allowable Value is based on the room or compartment size and the cooling provisions of the ventilation system.

BASES

ACTIONS

A Note has been provided to modify the ACTIONS related to Isolation Instrumentation channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable MSIV Instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided which allows separate Condition entry for each inoperable MSIV Instrumentation channel.

A.1

The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide isolation signals, the redundancy of the MSIV isolation design, and the low probability of an event requiring an MSIV isolation during this interval. However, this out of service time is only acceptable provided the associated Function still maintains MSIV isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the 12-hour Completion Time, the associated instrument channel must be verified to be in trip. This is acceptable because verifying the associated instrument channel in trip conservatively compensates for the inoperability by placing the MSIV isolation instrumentation in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

Alternatively, if it is not desirable to verify the associated instrument channel in trip (as in the case where it is desired to place the affected channel of sensors in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

Required Action B.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1 if the Required Action and Completion Time of Condition A is not met or if multiple, inoperable, untripped required channels (i.e., two or more required channels) for the same Function result in

BASES

ACTIONS (continued)

the Function not maintaining isolation capability. A Function is considered to be maintaining MSIV isolation capability when sufficient channels are OPERABLE or in trip such that the MSIV isolation logic will generate a trip signal from the given Function on a valid signal to at least one valve in the associated penetration flow path. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent.

C.1

If the required channel(s) is not restored to OPERABLE status, or verified to be in trip within the allowed Completion Time, or if MSIV isolation capability is not maintained, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

D.1

If the required channel(s) is not restored to OPERABLE status, or verified to be in trip within the allowed Completion Time, or if MSIV isolation capability is not maintained, plant operations may continue if the associated MSIV(s) and MSL drain isolation valve(s) are declared inoperable. Because this Function is required to ensure that the MSIVs and MSL drain isolation valves perform their intended function, sufficient remedial measures are provided by declaring the associated MSIV(s) and MSL drain isolation valves inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the Surveillance Requirements, the SRs for each isolation instrumentation Function are located in the SRs column of Table 3.3.6.1-1.

SR 3.3.6.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The RTIF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication, and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is based on operating experience that demonstrates channel failure is rare.

The CHANNEL CHECK supplements less formal, but more frequent checks of channels during normal operational use of the displays associated with the LCO required channels.

<u>SR 3.3.6.1.2</u>

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The RTIF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the Isolation Instrumentation channels.

<u>SR 3.3.6.1.3</u>

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the required

BASES

SURVEILLANCE REQUIREMENTS (continued)

channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Surveillance Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 9. ISOLATION SYSTEM RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the MSIV isolation instrumentation from the input variable sensors through the DTM digital trip function. This test overlaps the testing required by SR 3.3.6.2.2 to ensure complete testing of instrumentation channels and actuation circuitry.

STD COL 16.0-1-A 3.3.6.1-2

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each required division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

BASES

REFERENCES

1. Chapter 7, Figure 7.2-1.
2. Section 6.2.
3. Chapter 15.
4. Subsection 15.4.4.
5. Subsection 15.3.3.
6. Subsection 15.4.5.
7. Subsection 15.2.5.2.
8. Subsection 15.2.2.8.
9. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.6.2 Main Steam Isolation Valve (MSIV) Actuation

BASES

BACKGROUND	The MSIV actuation logic is designed to isolate the MSIVs and Main Steamline (MSL) drain isolation valves when one or more monitored parameters exceed the specified limit. The function of the MSIVs and MSL drain isolation valves, in combination with other accident mitigation systems, is to limit fission product release during postulated Design Basis Accidents (DBAs). MSIV and MSL drain isolation valve isolation within the times specified ensure that the release of radioactive materials to the environment will be consistent with the assumptions used in the analysis of DBAs. A detailed description of the MSIV instrumentation and MSIV actuation logic is provided in the Bases for LCO 3.3.6.1, "Main Steam Isolation Valve (MSIV) Instrumentation." This Specification provides requirements for the MSIV actuation circuitry consisting of the inputs to the Trip Logic Units (TLUs) through the Output Logic Units (OLUs) through the Load Drivers (LDs), and the associated timers. Operability of the MSIV instrumentation channels, up to and including the digital trip function of the Digital Trip module (DTM), is addressed by LCO 3.3.6.1. The OPERABILITY of the MSIVs, MSL drain isolation valves and their associated solenoids is addressed by LCO 3.6.1.3, "Containment Isolation Valves (CIVs)."
APPLICABLE SAFETY ANALYSES	The isolation signals generated by the MSIV instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of the MSIVs and MSL drain isolation valves to limit offsite doses. Refer to LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," Applicable Safety Analyses Bases, for more detail on MSIVs and MSL drain isolation valves. MSIV Actuation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Although there are four MSIV actuation divisions, only three are required to be OPERABLE to ensure no single automatic actuation division failure will preclude an MSIV isolation

BASES

LCO (continued)	to occur on a valid signal. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating." This is acceptable because the single-failure criterion is still met with three OPERABLE MSIV actuation divisions, and because each MSIV division is associated with and receives power from only one of the four electrical divisions.
APPLICABILITY	The MSIV actuation divisions are required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the Applicability of LCO 3.3.6.1 and LCO 3.6.1.3.
ACTIONS	A Note has been provided to modify the ACTIONS related to MSIV actuation divisions. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable MSIV actuation divisions provide appropriate compensatory measures for separate inoperable divisions. As such, a Note has been provided which allows separate Condition entry for each inoperable MSIV actuation division. <u>A.1</u> The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide isolation signals, the redundancy of the MSIV isolation design, and the low probability of an event requiring an MSIV isolation during this interval. However, this out of service time is only acceptable provided the associated Function still maintains MSIV actuation capability (refer to Required Actions B.1 Bases). If the inoperable required division cannot be restored to OPERABLE status within the 12-hour Completion Time, the affected actuation division must be verified to be in trip. This is acceptable because verifying the affected MSIV isolation actuation division in trip conservatively compensates for the inoperability by placing the MSIV isolation actuation in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

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ACTIONS (continued)

Alternatively, if it is not desirable to verify the affected required actuation division in trip (as in the case where it is desired to place the affected division in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

If the Required Actions and associated Completion Times of Condition A are not met or two or more required MSIV actuation divisions are inoperable, the affected actuation device(s) must be declared inoperable immediately. In this Condition, a loss of MSIV actuation capability occurs to numerous actuation devices. MSIV actuation capability is considered to be maintained when sufficient required actuation divisions will generate an isolation from a given Function on a valid signal so that at least one valve in the associated penetration flow path is isolated.

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the MSIV actuation divisions, including the two-out-of-four function of the Trip Logic Unit (TLU), Output Logic Unit (OLU), and Load Drivers (LDs) for a specific division. The testing in LCO 3.3.6.1 and LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.3.6.2.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 3. ISOLATION SYSTEM RESPONSE TIME may be verified by actual response time measurements in any series of

BASES

SURVEILLANCE REQUIREMENTS (continued)

sequential, overlapping, or total channel measurements. This test encompasses the MSIV actuation circuitry consisting of the inputs to the TLUs through the OLUs through the LDs, and the associated timers. This test overlaps the testing required by SR 3.3.6.1.4 to ensure complete testing of instrumentation channels and actuation circuitry.

STD COL 16.0-1-A 3.3.6.2-1

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each required division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Section 6.2.
2. Chapter 15.
3. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.6.3 Isolation Instrumentation

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BACKGROUND

The isolation instrumentation contained in this specification provides the capability to generate isolation signals to the containment isolation valves, the reactor building heating, ventilation and air conditioning system isolation dampers, and feedwater isolation valves. The function of the isolation valves and dampers, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). The function of the feedwater isolation valves is to also limit the mass addition of water into containment during and following a design basis feedwater line rupture inside containment. The function of the reactor water cleanup/shutdown cooling (RWCU/SDC) isolation valves in MODES 5 and 6 is to protect the core by isolating the RWCU/SDC system from the reactor pressure vessel and minimizing a potential loss of coolant resulting from a line break in the RWCU/SDC system. The function of high pressure control rod drive (HP CRD) makeup water injection isolation is to prevent the long-term addition of inventory into containment following a loss of coolant accident (LOCA). The function of the ICS isolation that occurs when 2 or more Depressurization Valves (DPVs) are open is to mitigate the accumulation of radiolytic hydrogen and oxygen that could result in a detonation.

Technical Specifications are required by 10 CFR 50.36 to contain limiting safety system settings (LSSS) defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is

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BACKGROUND (continued)

initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits, including the requirements for determining that the channel is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for

BACKGROUND (continued)

the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value which is the least conservative value of the as-found setpoint that a channel can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The containment isolation function is performed by the Leak Detection and Isolation (LD&IS) portion of the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System. Functional diversity is provided by monitoring a

BACKGROUND (continued)

wide range of independent parameters. Containment isolation occurs in response to signals from any of the following:

- Reactor Vessel Water Level - Low, Level 2,
- Reactor Vessel Water Level - Low, Level 1,
- Drywell Pressure - High,
- Main Steam Tunnel Ambient Temperature - High,
- RWCU/SDC Differential Mass Flow - High (per subsystem),
- Isolation Condenser Steam Line Flow - High (per Isolation Condenser),
- Isolation Condenser Condensate Return Line Flow - High (per Isolation Condenser),
- Isolation Condenser Pool Vent Discharge Radiation - High (per Isolation Condenser), or
- Reactor Building Exhaust Radiation – High.

The RWCU/SDC isolation function in MODES 5 and 6 is performed by the LD&IS portion of the SSLC/ESF System. RWCU/SDC isolation in MODES 5 and 6 isolation occurs in response to signals from either of the following:

- Reactor Vessel Water Level - Low, Level 2, or
- RWCU/SDC Differential Mass Flow - High (per subsystem),

The feedwater isolation function is performed by the LD&IS portion of the SSLC/ESF. Feedwater isolation occurs in response to any of the following:

- Feedwater Lines Differential Pressure - High concurrent with Drywell Pressure - High,
- Drywell Pressure - High concurrent with Drywell Water Level - High,
- Reactor Vessel Water Level - Low, Level 0.5, or
- Drywell Pressure - High-High.

The ICS isolation function that mitigates the accumulation of combustible gas is performed by the LD&IS portion of the

BASES

BACKGROUND (continued)

SSLC/ESF. ICS isolation occurs in response to the following signal:

- Depressurization Valve – Open

At least 2 DPVs must be open for this ICS isolation to be initiated.

The HP CRD isolation function is performed by the LD&IS portion of the SSLC/ESF. HP CRD isolation occurs in response to any of the following:

- Drywell Pressure - High concurrent with Drywell Water Level - High, or
- Gravity-Driven Cooling System (GDCS) Pool Water Level - Low.

The SSLC/ESF controls the initiation signals and logic for isolation. SSLC/ESF is a four division, separated protection logic system designed to provide a very high degree of assurance to both ensure isolation when required and prevent inadvertent initiation. The input and output trip determinations for all isolation functions are based upon a two-out-of-four logic arrangement. Each division of SSLC/ESF is configured such that all functions (e.g., the digital trip module (DTM) function and voter logic unit (VLU) function) are implemented in triply redundant processors to support the requirement that single divisional failures cannot result in inadvertent actuation.

Four separate instrument channels are used to monitor isolation initiation parameters. Signals from sensors are multiplexed at the divisional level and triply redundant sensor data is then transmitted to the SSLC/ESF triply redundant DTM function for setpoint comparison. The output of each divisional DTM function (a trip/no-trip condition) is routed to all four divisional triply redundant VLU functions such that each divisional VLU function receives input from each of the four divisional DTM functions.

For maintenance purposes and added reliability, each DTM function has a division of sensors bypass such that all instruments in that division will be bypassed in the trip logic at the VLU functions. Thus, each VLU function will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time.

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BACKGROUND (continued)

The processed trip signal from its own division and trip signals from the other three divisions are processed in the triply redundant VLU function for two-out-of-four voting.

The LD&IS logic is designed to seal-in the isolation signal once the trip has been initiated. The isolation signal overrides any control action to cause the closure of isolation valves. Reset of the isolation logic is required before any isolation valve can be manually opened.

Equipment within a single division is powered from the safety-related power source of the same division.

This Specification provides Operability requirements for the isolation instrumentation from the input variable sensors through the DTM function. Operability requirements for the isolation actuation circuitry consisting of timers, VLU functions, and load drivers are provided by LCO 3.3.6.4, "Isolation Actuation." Operability requirements for the actuated components are addressed in LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," and LCO 3.6.3.1, "Reactor Building (Contaminated Area Ventilation Subsystem (CONAVS) Area)."

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The containment isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of containment isolation valves and reactor building boundary isolation dampers to limit off-site doses. Refer to LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," Applicable Safety Analyses Bases, for more detail on containment isolation valves and LCO 3.6.3.1, "Reactor Building (Contaminated Area Ventilation Subsystem (CONAVS) Area)," Applicable Safety Analyses Bases for more detail on reactor building boundary isolation dampers.

The RWCU/SDC isolation signals generated by the isolation instrumentation are assumed in the analyses of Reference 3 to initiate closure of the RWCU/SDC isolation valves to protect the core by minimizing a potential loss of reactor pressure vessel coolant inventory in MODES 5 and 6.

The feedwater isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of feedwater isolation valves to limit mass water additions to the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

containment during and following a design basis feedwater line rupture inside containment.

The ICS isolation signals generated by the isolation instrumentation in response to the opening of 2 or more DPVs are assumed in the safety analyses of References 1 and 2 to mitigate the accumulation of radiolytic hydrogen and oxygen that could result in a detonation that would fail the ICS condensers and cause a breach of containment.

The HP CRD isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of HP CRD makeup water injection isolation valves to limit mass water additions to the containment following a LOCA.

Isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). However, certain monitored instrumentation parameters are retained for other reasons and are described below in the individual process parameter discussion.

The OPERABILITY of the isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.3-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate. Each channel must also respond within its assumed response time, where appropriate. $NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is nonconservative with respect to its required Allowable Value.

In general, the individual monitored process parameters are required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the Applicability of LCO 3.6.1.3 and LCO 3.6.3.1. Functions that have different Applicabilities are discussed below in the individual Functions discussion.

Although there are four channels of isolation instrumentation for each function, only three channels of isolation instrumentation for each function are required to

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating." This is acceptable because the single-failure criterion is met with three OPERABLE isolation instrumentation channels, and because each isolation instrumentation division is associated with and receives power from only one of the four electrical divisions.

The specific Applicable Safety Analyses, LCO and specific Applicability discussions are provided below on a Function basis.

1. Reactor Vessel Water Level - Low, Level 2

Low reactor pressure vessel (RPV) water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The isolations of valves whose penetration communicate with the containment or the reactor vessel and the isolation of the reactor building boundary isolation dampers limit the release of fission products to help ensure that offsite does limits are not exceeded. The Reactor Vessel Water Level - Low, Level 2 is credited in the LOCA inside containment radiological analysis (Ref. 4).

In MODES 5 and 6, low RPV water level may indicate a loss of coolant. Should RPV water level decrease too far, the ability to cool the core may be threatened. Closure of the RWCU/SDC isolation valves isolates the system from the RPV, minimizing the potential loss of coolant inventory. The Reactor Vessel Water Level - Low, Level 2 is implicitly credited in the shutdown probabilistic risk assessment (Ref. 3), and therefore satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Reactor Vessel Water Level - Low, Level 2 signals are initiated from four level sensors that sense the difference between the pressure due to a constant column (reference leg) of water and the pressure due to the actual water level (variable leg) in the vessel. Three channels of Reactor Vessel Water Level - Low, Level 2 Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Reactor Vessel Water Level - Low, Level 2 Allowable Value was chosen to be the same as the Isolation Condenser System Reactor Vessel Water Level - Low, Level 2 Allowable Value.

This Function isolates the RWCU/SDC lines, Equipment and Floor Drain System lines, Containment Inerting System lines, and the Fuel and Auxiliary Pools Cooling System process lines.

2. Reactor Vessel Water Level - Low, Level 1

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The isolations of valves whose penetration communicate with the containment or the reactor vessel and the isolation of the reactor building boundary isolation dampers limit the release of fission products to help ensure that offsite does limits are not exceeded. The Reactor Vessel Water Level - Low, Level 1 channels are provided as a backup to the Reactor Vessel Water Level - Low, Level 2 channels and is not credited in the safety analysis.

Reactor Vessel Water Level - Low, Level 1 signals are initiated from four level sensors that sense the difference between the pressure due to a constant column (reference leg) of water and the pressure due to the actual water level (variable leg) in the vessel. Three channels of Reactor Vessel Water Level - Low, Level 1 Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low, Level 1 Allowable Value was chosen to be the same as the Automatic Depressurization System Reactor Vessel Water Level - Low, Level 1 Allowable Value.

This Function isolates the RWCU/SDC lines, Process Radiation Monitoring System lines, Equipment and Floor Drain System lines, Containment Inerting System lines, Chilled Water System lines, and the Fuel and Auxiliary Pools Cooling System process lines.

3. Drywell Pressure - High

High drywell pressure can indicate a break in the reactor coolant pressure boundary. The isolations of valves whose

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

penetration communicate with the containment and the isolation of the reactor building boundary isolation dampers limit the release of fission products to help ensure that offsite dose limits are not exceeded. The Drywell Pressure - High channels are not explicitly credited in the safety analyses but retained for the overall redundancy and diversity of the isolation instrumentation.

High drywell pressure signals are initiated from four pressure sensors that sense the pressure in the drywell. Three channels of Drywell Pressure – High are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Drywell Pressure - High Allowable Value was chosen to be the same as the Reactor Protection System Drywell Pressure - High Allowable Value.

This Function isolates the Process Radiation Monitoring System lines, Equipment and Floor Drain System lines, Containment Inerting System lines, Chilled Water System lines, Fuel and Auxiliary Pools Cooling System process lines, and High Pressure Nitrogen Gas Supply System lines. In addition, this Function, in conjunction with either Feedwater Lines Differential Pressure - High or Drywell Water Level - High, isolates the feedwater lines. This Function, in conjunction with Drywell Water Level - High, also isolates the HP CRD makeup water injection line.

4. Main Steam Tunnel Ambient Temperature - High

Main Steam Tunnel Ambient Temperature - High Function is provided to detect a leak in the reactor coolant pressure boundary. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, off-site dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis because bounding analyses are performed for large breaks such as a MSL break.

Temperature signals are initiated from thermocouples located away from the main steam lines so they are only sensitive to ambient air temperature. Three channels of Main Steam Tunnel Temperature - High Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The ambient temperature monitoring Allowable Value is based on the room or compartment size and the cooling provisions of the ventilation system.

The Main Steam Tunnel Ambient Temperature - High Function isolates the RWCU/SDC System lines.

5. RWCU/SDC Differential Mass Flow - High (per subsystem)

The Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System Differential Mass Flow - High signal is provided to detect a break in the RWCU System outside containment. Should the reactor coolant continue to flow out the break off-site dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when RWCU/SDC System Differential Mass Flow - High is sensed to prevent exceeding offsite doses. This Function is directly assumed in the RWCU/SDC System line failure event outside containment (Ref. 5).

In MODES 5 and 6, high RWCU/SDC differential flow may indicate a loss of coolant. Should RPV water level decrease too far, the ability to cool the core may be threatened. Closure of the RWCU/SDC isolation valves isolates the system from the RPV, minimizing the potential loss of coolant inventory. The Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System Differential Mass Flow - High is implicitly credited in the shutdown probabilistic risk assessment (Ref. 3), and therefore satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Each RWCU/SDC subsystem includes a suction line near the mid level of the reactor pressure level (RPV) and another suction line at the RPV bottom. Each suction line includes a venturi-type flow element inside containment. Each flow element is instrumented with four flow sensors. The temperature of each suction line is also monitored by four temperature elements close to the venturi-type flow element. Each RWCU/SDC subsystem also includes a return line to the feedwater lines and another return line to the overboarding lines. These lines are instrumented consistent with the suction lines. Each flow rate signal is converted to a mass flow rate signal using its associated temperature element. A differential flow rate is calculated from the difference between the suction flows and return flows. This differential flow rate is compared to the setpoint. Therefore, each differential flow channel consists of all the components necessary to calculate the differential flow signal and provide a trip signal.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Three channels of the RWCU/SDC System Differential Mass Flow - High Function per RWCU/SDC subsystem are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The RWCU/SDC System Differential Mass Flow - High Allowable Value ensures that a leak or a line break of the RWCU/SDC piping is detected.

This Function isolates the RWCU/SDC lines.

6, 7 and 8. <u>Isolation Condenser Steam and Condensate Return Line Flow -High and Pool Vent Discharge Radiation - High</u>

The Isolation Condenser Steam Line Flow - High, Condensate Return Line Flow - High, and Pool Vent Discharge Radiation - High Functions are provided to monitor the pressure boundary status of each individual Isolation Condenser System (ICS) subsystem. The Isolation Condenser Steam Line Flow - High and Condensate Return Line Flow - High Functions will isolate the associated subsystem when a leak or a break has occurred while the Pool Vent Discharge Radiation - High Function will isolate the associated subsystem when leakage is detected outside the drywell. These Functions are not assumed in any transient or accident analysis since bounding analyses are performed for large breaks such as MSL breaks.

The isolation signals can be initiated from a total of 12 instruments per ICS subsystem, with each ICS subsystem having four differential pressure sensors per ICS subsystem steam line, four differential pressure sensors per ICS subsystem condensate line, and four radiation detectors located in its associated ICS subsystem vent discharge into the pool area. The flow instrumentation is designed to detect leakage both inside and outside of the drywell. The radiation detectors are designed to detect leakage outside of containment. Three channels of each monitored parameter for each ICS subsystem are required to be OPERABLE to ensure no single instrument failure can preclude the isolation functions.

The Allowable Value is chosen to be low enough to ensure that the isolation occurs to prevent fuel damage and maintains the MSL break event as the bounding event.

These Functions isolate the associated ICS lines.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Depressurization Valve – Open

The DPV – Open Function is provided to indicate that RPV depressurization has occurred and that the ICS is no longer required to perform its heat removal function. In this situation, the ICS is required to be isolated to mitigate the accumulation of radiolytic hydrogen and oxygen that could result in a detonation that would cause a containment breach. This Function is assumed in the safety analyses of References 1 and 2.

The position of each DPV is measured by 4 divisional position switches. The logic is arranged such that ICS Isolation will occur whenever 2 or more DPVs are open. Three channels of the DPV – Open Function are required to be OPERABLE for each DPV required by LCO 3.5.1, "Automatic Depressurization System (ADS) – Operating," to ensure no single instrument failure can preclude the isolation function.

This Function isolates the ICS lines.

10. Feedwater Lines Differential Pressure - High

The Feedwater Line Differential Pressure - High signal is provided to detect a break in the feedwater lines inside containment. Should the feedwater continue to flow into containment, containment integrity could be challenged as a result of the mass and energy addition to the containment drywell from the external feedwater system. Therefore, isolation of the feedwater system flow is initiated when Feedwater Lines Differential Pressure - High is sensed to protect containment integrity. This Function is implicitly assumed in the safety analyses of References 1 and 2.

The differential pressure between the two feedwater lines is monitored by four divisions of LD&IS. A high differential pressure is indicative of a feedwater line break inside and outside the containment.

Three channels of the Feedwater Line Differential Pressure - High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Feedwater Line Differential Pressure - High Allowable Value ensures that a leak or a line break of the feedwater piping is detected, in accordance with the containment analyses (Ref. 1).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function in conjunction with the Drywell Pressure - High Function isolates the feedwater lines.

11. Reactor Building Exhaust Radiation - High

High radiation in the reactor building exhaust or the refueling area exhaust is an indication of fission gases from a leak or an accident. The release may have originated from the containment due to a break in the reactor coolant pressure boundary or the refueling floor due to a fuel handling accident. When a Reactor Building Exhaust Radiation - High signal is detected, the Reactor Building Heating, Ventilation and Air Conditioning System is isolated. This Function is assumed to be available during high energy line break conditions and during a LOCA because the reactor building is credited for hold up and as a plate out barrier.

The Reactor Building Exhaust Radiation - High signal is initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building. Three channels of the Reactor Building Exhaust Radiation - High Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation functions.

The Reactor Building Exhaust Radiation - High Allowable Value is chosen to ensure the RB is isolated prior to radioactivity release exceeding the assumptions of the offsite does analyses.

12. Drywell Water Level - High

High drywell water level is an indication of a possible line break inside containment. This Function is provided to ensure that feedwater and HP CRD are isolated in the event of a LOCA, but remains capable of coolant injection for other accident scenarios.

Drywell water level is monitored by four channels of water level instrumentation. Three channels of the Drywell Water Level - High Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Drywell Water Level - High Allowable Value is chosen to be low enough to ensure feedwater isolation occurs, limiting the flow of condensate into containment in accordance with the containment analyses (Ref. 1).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function in conjunction with the Drywell Pressure - High Function isolates the feedwater lines and the HP CRD makeup water injection line.

13. Reactor Vessel Water Level - Low, Level 0.5

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The isolations of valves whose penetration communicate with the containment or the reactor vessel limit the release of fission products to help ensure that offsite does limits are not exceeded. Reactor Vessel Water Level - Low, Level 0.5 signals are initiated from four fuel zone level sensors.

The Reactor Vessel Water Level - Low, Level 0.5 Allowable Value is chosen to ensure that feedwater line isolations occurs in accordance with the assumptions of Reference 4.

Three channels of Reactor Vessel Water Level - Low, Level 0.5 Function are required to be OPERABLE to ensure that no single instrument failure can preclude feedwater line isolation.

14. Drywell Pressure - High-High

High drywell pressure is an indication of a possible line break inside containment. This Function is provided to ensure that feedwater is isolated in the event of a LOCA, but remains capable of coolant injection for other accident scenarios.

Drywell pressure is monitored by four channels of pressure instrumentation. Three channels of the Drywell Pressure - High-High Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Drywell Pressure - High-High Allowable Value is chosen to be higher than the scram setpoint to prevent undesired initiation, and low enough to retain effectiveness throughout the entire spectrum of LOCA events.

This Function isolates the feedwater lines.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

15. Gravity-Driven Cooling System Pool Water Level - Low

Low GDCS pool water level indicates the injection of water from the GDCS pools in the event of a LOCA. This Function is provided to ensure that the HP CRD makeup water injection is isolated to prevent the long-term addition of inventory to the containment following GDCS injection in response to a LOCA.

GDCS pool water level is monitored by four channels of water level indication in each GDCS pool. Three channels of the GDCS Pool Water Level - Low Function are required to be OPERABLE in each GDCS pool. This Function initiates upon a low level in two out of the three GDCS pools.

The GDCS Pool Water Level - Low Allowable Value is determined by analysis to ensure effectiveness under the full spectrum of LOCA events.

This Function isolates the HP CRD makeup water injection line.

ACTIONS

The ACTIONS are modified by two NOTES. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration flow path can be rapidly isolated when a need for isolation is indicated. Note 2 has been provided to modify the ACTIONS related to Isolation Instrumentation channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Isolation Instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided which allows separate Condition entry for each inoperable Isolation Instrumentation channel.

BASES

ACTIONS (continued)

A.1

With one or more Functions with one required channel inoperable, the affected required channel must be restored to OPERABLE status within 12 hours. The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide isolation signals, the redundancy of the isolation design, and the low probability of an event requiring isolation during this interval. However, this out of service time is only acceptable provided the associated Function still maintains isolation capability (refer to Required Actions B.1 Bases). If the inoperable required channel cannot be restored to OPERABLE status within the 12-hour Completion Time, the affected instrumentation division must be verified to be in trip. This is acceptable because verifying the affected isolation instrumentation division in trip conservatively compensates for the inoperability by placing the isolation instrumentation in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

Alternatively, if it is not desirable to verify the required instrument channel in trip (as in the case where it is desirable to place the affected channel of sensors in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.6.3-1 if the Required Action and Completion Time of Condition A is not met or if multiple, inoperable, untripped required channels for the same Function result in the Function not maintaining isolation capability. A Function is considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that the isolation logic will generate a trip signal from the given Function on a valid signal so that at least one valve in the associated penetration flow path is isolated. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed.

BASES

ACTIONS (continued)

C.1

If the affected instrumentation channel cannot be verified to be in trip within the specified Completion Time or if isolation capability is not maintained, plant operations may continue if the associated Containment Isolation Valve(s) (CIVs) is declared inoperable immediately. Because this Function is required to ensure that the CIVs perform their intended function, sufficient remedial measures are provided by declaring the associated CIV(s) inoperable.

D.1 and D.2

If the affected instrumentation channel cannot be verified to be in trip within the specified Completion Time or if isolation capability is not maintained, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1 and E.2

If the affected instrumentation channel cannot be verified to be in trip within the specified Completion Time or if isolation capability is not maintained, the associated flow path should be isolated. However, if the RWCU/SDC function is needed to provide core cooling, these Required Actions allow the flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RWCU/SDC system (i.e., provide alternate decay heat removal capabilities so the flow path can be isolated). ACTIONS must continue until the channel is restored to OPERABLE status or the RWCU/SDC system is isolated.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the Surveillance Requirements, the SRs for each isolation instrumentation Function are located in the SRs column of Table 3.3.6.3-1.

SR 3.3.6.3.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication, and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is based on operating experience that demonstrates channel failure is rare.

The CHANNEL CHECK supplements less formal, but more frequent checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the Isolation Instrumentation channels and the self-diagnostic features that monitor the channels for proper operation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Surveillance Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.3.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 6.

ISOLATION SYSTEM RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the isolation instrumentation from the input variable sensors through the DTM function. This test overlaps the testing required by SR 3.3.6.4.2 to ensure complete testing of instrumentation channels and actuation circuitry.

A Note to the Surveillance states that the radiation detectors may be excluded from ISOLATION SYSTEM RESPONSE TIME testing. This Note is necessary because of the difficulty of generating an appropriate detector input signal and because the principles of detector operation virtually ensure an instantaneous response time. Response Time for radiation detection channels shall be measured from detector output or the input of the first electronic component in the channel.

STD COL 16.0-1-A 3.3.6.3-2

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the required channels associated with each division are

BASES

SURVEILLANCE REQUIREMENTS (continued)	alternately tested. The 24-month test Frequency is consistent with the refueling cycle and has with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.
REFERENCES	1. Section 6.2. 2. Chapter 15. 3. NEDO-33201, ESBWR Certification Probabilistic Risk Assessment, Revision 6, October 2010. 4. Subsection 15.4.4. 5. Subsection 15.4.9. 6. Section 15.2.

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B 3.3 INSTRUMENTATION

B 3.3.6.4 Isolation Actuation

BASES

BACKGROUND

The isolation actuation logic is designed to isolate the affect penetration flow paths when one or more monitored parameters exceed the specified limit. The isolation actuation logic actuates the following containment isolation flow paths: (a) Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System lines, (b) Isolation Condenser System (ICS) lines, (c) Process Radiation Monitoring System lines, (d) Equipment and Floor Drain System lines, (e) Containment Inerting System lines, (f) Chilled Water System lines, (g) Fuel and Auxiliary Pools Cooling System (FAPCS) process lines, and (h) High Pressure Nitrogen Gas Supply System lines. The isolation actuation logic also isolates the reactor building boundary isolation dampers. The function of the containment isolation valves and reactor building boundary isolation dampers, in combination with other accident mitigation systems, is to limit fission product release during postulated Design Basis Accidents (DBAs). Containment and reactor building isolation within the times specified ensure that the release of radioactive materials to the environment will be consistent with the assumptions used in the analysis of DBAs.

The isolation actuation logic is also designed to isolate the RWCU/SDC System from the reactor pressure vessel (RPV) in MODES 5 and 6, isolate feedwater flow into containment and trip main feedwater pump breakers, isolate the ICS when 2 or more Depressurization Valves (DPVs) are open, and isolate high pressure control rod drive (HP CRD) makeup water injection when one or more monitored parameters exceed the specified limit. The function of the feedwater isolation valves is to limit the mass addition of water into containment during and following a design basis feedwater line rupture inside containment. The function of the reactor water cleanup/shutdown cooling (RWCU/SDC) isolation valves in MODES 5 and 6 is to protect the core by isolating the RWCU/SDC system from the reactor pressure vessel and minimizing a potential loss of coolant resulting from a line break in the RWCU/SDC system. The function of the ICS isolation that occurs when 2 or more DPVs are open is to mitigate the accumulation of radiolytic hydrogen and oxygen that could result in a detonation. The function of the HP CRD

BACKGROUND (continued)	makeup water isolation is to prevent the long-term addition of inventory to the containment following a loss of coolant accident (LOCA). A detailed description of the isolation instrumentation and isolation actuation logic is provided in the Bases for LCO 3.3.6.3, "Isolation Instrumentation." This Specification provides Operability requirements for the isolation actuation circuitry consisting of timers, voter logic unit (VLU) functions, and load drivers. Operability requirements for the isolation instrumentation from the input variable sensors through the DTM function are provided by LCO 3.3.6.3, "Isolation Instrumentation." Operability requirements for the actuated components are addressed in LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," and LCO 3.6.3.1, "Reactor Building (Contaminated Area Ventilation Subsystem (CONAVS) Area)."
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The containment isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of valves and reactor building and boundary isolation dampers to limit off site doses. Refer to LCO 3.6.1.3, Applicable Safety Analyses, for more details of containment isolation valves. Refer to LCO 3.6.3.1, Applicable Safety Analyses, for more details of the reactor building isolation dampers. The RWCU/SDC isolation signals generated by the isolation instrumentation are assumed in the analyses of Reference 3 to initiate closure of the RWCU/SDC isolation valves to protect the core by minimizing a potential loss of reactor pressure vessel coolant inventory in MODES 5 and 6. The feedwater isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate closure of feedwater isolation valves to limit mass water additions to the containment during and following a design basis feedwater line rupture inside containment. The ICS isolation signals generated by the isolation instrumentation in response to the opening of 2 or more DPVs are assumed in the safety analyses of References 1 and 2 to mitigate the accumulation of radiolytic hydrogen and oxygen that could result in a detonation that would fail the ICS condensers and cause a breach of containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The HP CRD isolation signals generated by the isolation instrumentation are assumed in the safety analyses of References 1 and 2 to initiate isolation of the HP CRD makeup water injection line to prevent the long-term addition of inventory to the containment following a LOCA.

Isolation Actuation satisfies Criteria 3 and 4 of 10 CFR 50.36(c)(2)(ii).

Although there are four isolation actuation divisions, only three are required to be OPERABLE to ensure no single automatic actuation division failure will preclude an isolation to occur on a valid signal. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating." This is acceptable because the single-failure criterion is still met with three OPERABLE isolation actuation divisions, and because each isolation division is associated with and receives power from only one of the four electrical divisions.

The individual containment isolation actuation divisions are required to be OPERABLE in the MODES 1, 2, 3, and 4 consistent with the Applicability of LCO 3.6.1.3 and LCO 3.6.3.1. The feedwater isolation valve actuation divisions are required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the assumptions of References 1 and 2. The RWCU/SDC isolation actuation division is also required to be OPERABLE in MODES 5 and 6 consistent with the assumptions of Reference 3.

1. Reactor Water Cleanup/Shutdown Cooling System Isolation

The RWCU/SDC System Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 2; Reactor Vessel Water Level - Low, Level 1; Main Steam Tunnel Ambient Temperature - High; and Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow - High (per RWCU/SDC subsystem) Functions. In MODES 5 and 6, the RWCU/SDC System Isolation actuation divisions receive input from the Reactor Vessel Water Level - Low, Level 2 and from the Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow - High (Per RWCU/SDC subsystem) Functions. Three Reactor Water Cleanup/Shutdown Cooling System Isolation actuation

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

2. Isolation Condenser System Isolation

The Isolation Condenser System Isolation actuation divisions receive input from the following isolation instrumentation: Isolation Condenser Steam Line Flow - High (per ICS subsystem); Isolation Condenser Condensate Line Flow - High (per ICS subsystem); Isolation Condenser Pool Vent Discharge Radiation - High (per ICS subsystem); and Depressurization Valve - Open Functions. Three Isolation Condenser System Isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

3. Process Radiation Monitoring System Isolation

The Process Radiation Monitoring System Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 1; and Drywell Pressure - High Functions. Three Process Radiation Monitoring System Isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

4. Equipment and Floor Drain System Isolation

The Equipment and Floor Drain System Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 2; Reactor Vessel Water Level - Low, Level 1; and Drywell Pressure High Functions. Three Equipment and Floor Drain System Isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

5. Containment Inerting System Isolation

The Containment Inerting System Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 2; Reactor Vessel Water Level - Low, Level 1 and Drywell Pressure - High Functions. Three Containment Inerting System Isolation actuation divisions are required to be OPERABLE to

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ensure no single isolation actuation failure can preclude the isolation function.

6. Chilled Water System Isolation

The Chilled Water System Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 1; and Drywell Pressure - High Functions. Three Chilled Water System Isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

7. Fuel and Auxiliary Pools Cooling System Process Lines

The FAPCS Process Lines isolation actuation divisions receive input from the following isolation instrumentation: the Reactor Vessel Water Level - Low, Level 2; Reactor Vessel Water Level - Low, Level 1; and Drywell Pressure - High Functions. Three FAPCS Process Lines isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

8. Reactor Building Heating, Ventilation and Air Conditioning System Isolation

Reactor Building Heating, Ventilation and Air Conditioning System Isolation actuation divisions receive input from the Reactor Building Exhaust Radiation - High. Three Reactor Building Heating, Ventilation and Air Conditioning System Isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

9. High Pressure Nitrogen Gas Supply Isolation

The High Pressure Nitrogen Gas Supply Isolation actuation divisions receive input from the following isolation instrumentation: Reactor Vessel Water Level - Low, Level 1; and Drywell Pressure - High Functions. Three High Pressure Nitrogen Gas Supply isolation actuation divisions are required to be OPERABLE to ensure no single isolation actuation failure can preclude the isolation function.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Feedwater Isolation Valves Isolation

The Feedwater Isolation Valve Isolation actuation divisions receive input from the Feedwater Lines Differential Pressure - High, Drywell Water Level - High, Reactor Vessel Level - Low, Level 0.5, Drywell Pressure - High, and Drywell Pressure - High-High isolation instrumentation channels. Each feedwater line includes one feedwater control valve installed as the inboard containment isolation valve and the first of two in-series feedwater isolation valves is installed as the outboard containment isolation valve. The second feedwater isolation valve and feedwater control valve provide functional redundancy. This Function actuates the two feedwater isolation valves in each feedwater line to provide isolation in the event of a feedwater line break inside containment. Three Feedwater Isolation Valve - Isolation actuation divisions are required to be OPERABLE to ensure that no single isolation actuation failure can preclude the Function.

11. High Pressure Control Rod Drive Isolation

The HP CRD Isolation actuation divisions receive input from the Gravity Driven-Driven Cooling System (GDCS) Pool Water Level - Low, Drywell Pressure - High, and Drywell Water Level - High isolation instrumentation channels. The HP CRD makeup water injection line contains two in-series isolation valves. This Function actuates the two isolation valves in the HP CRD makeup water injection line to prevent addition of inventory to the containment by this pathway following a LOCA. Three HP CRD Isolation actuation divisions are required to be OPERABLE to ensure that no single isolation actuation failure can preclude the isolation function.

ACTIONS

The ACTIONS are modified by two NOTES. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration flowpath can be rapidly isolated when a need for isolation is indicated. Note 2 has been provided to modify the ACTIONS related to isolation actuation. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition.

ACTIONS (continued)

Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable isolation actuation provides appropriate compensatory measures for separate inoperable isolation actuation divisions. As such, a Note has been provided which allows separate Condition entry for each inoperable isolation actuation division.

A.1

The 4-hour Completion Time is consistent with the Completion Times of LCO 3.6.1.3 for penetration flow paths with two CIVs and is acceptable based on engineering judgment considering the diversity of sensors available to provide isolation signals, the redundancy of the isolation design, and the low probability of an accident requiring isolation during this time. However, this out of service time is only acceptable provided the associated Function still maintains isolation actuation capability (refer to Required Actions B.1 Bases). If the inoperable division cannot be restored to OPERABLE status within the 4-hour Completion Time, the affected required actuation division must be verified to be in trip. This is acceptable because verifying the affected isolation actuation division in trip conservatively compensates for the inoperability by placing the isolation actuation in a one-out-of-two configuration, restoring the capability to accommodate a single failure.

Alternatively, if it is not desirable to verify the affected required actuation division in trip (as in the case where it is desired to place the affected division in bypass), Condition C must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.6.4-1 if the Required Action and Completion Time of Condition A is not met or if multiple, inoperable, untripped required divisions of isolation actuation (i.e., one or two divisions associated with each isolation valve or damper in a penetration flow path) result in the isolation actuation capability not maintained. Isolation automatic actuation capability is considered to be maintained when sufficient actuation divisions are OPERABLE or in trip such that the isolation logic will generate a trip signal on a valid signal to close

ACTIONS (continued)

one valve on the associated penetration. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed.

C.1

With the Required Action and associated Completion Time of Condition A not met, or if isolation actuation capability is not maintained, the affected isolation actuation device(s) must be declared inoperable immediately. Isolation actuation capability is considered to be maintained when sufficient actuation divisions are OPERABLE such that isolation logic will generate an actuation signal on a valid signal.

D.1 and D.2

With the Required Action and associated Completion Time of Condition A not met, or if two or more required actuation divisions inoperable, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours The Completion Time is reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1 and E.2

If the affected actuation division cannot be verified to be in trip within the specified Completion Time or if isolation capability is not maintained, the associated flow path should be isolated. However, if the RWCU/SDC function is needed to provide core cooling, these Required Actions allow the flow path to remain unisolated provided action is immediately initiated to restore the division to OPERABLE status or to isolate the RWCU/SDC system (i.e., provide alternate decay heat removal capabilities so the flow path can be isolated). ACTIONS must continue until the division is restored to OPERABLE status or the RWCU/SDC system is isolated.

BASES

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each isolation actuation Function are located in the SRs column of Table 3.3.6.4-1.

SR 3.3.6.4.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the isolation actuation divisions. The testing in LCO 3.3.6.3, LCO 3.6.1.3, and LCO 3.6.3.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.3.6.4.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 4.

ISOLATION SYSTEM RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the isolation actuation circuitry consisting of timers, VLU functions, and load drivers. This test overlaps the testing required by SR 3.3.6.3.4 to ensure complete testing of instrumentation channels and actuation divisions.

STD COL 16.0-1-A 3.3.6.4-1

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each required division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4.3

A system functional test is performed to verify that the mechanical portions of the actuation function operate as designed when demanded. This includes verifying that RWCU/SDC isolation valves, feedwater isolation valves, and HP CRD makeup water injection isolation valves automatically close. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.1 and LCO 3.3.8.1 (for RWCU/SDC isolation valves) overlaps this SR to provide complete testing of the safety function.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. Section 6.2.
2. Chapter 15.
3. NEDO-33201, ESBWR Certification Probabilistic Risk Assessment, Revision 6, October 2010.
4. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Instrumentation

BASES

BACKGROUND

NAPS COL 16.0-1-A 3.3.7.1-2

The purpose of the CRHAVS instrumentation is to initiate appropriate actions to ensure the CRHAVS and control room habitability area (CRHA) boundary provide a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity. The equipment involved with CRHAVS is described in the Bases for LCO 3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)."

The safety-related function of the CRHAVS used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems, or Emergency Filter Units (EFUs), for treatment of outside supply air and a CRHA boundary that limits the inleakage of unfiltered air. Upon receipt of a high control room air intake radiation initiation signal (indicative of conditions that could result in radiation exposure to CRHA occupants), or upon an extended loss of AC power, the CRHA isolation mode is initiated as follows:

- The primary divisional fan of the primary EFU is energized,
- The primary EFU redundant isolation dampers are opened,
- The main air supply duct and restroom exhaust isolation dampers are closed, and
- The nonsafety-related normal ventilation fans are stopped.

If all onsite and offsite AC power is lost, one of the nonsafety-related recirculation AHUs operates for a minimum of two hours using the nonsafety-related Uninterruptible AC Power Supply System to dissipate heat from operation of the nonsafety-related main control room Nonsafety-Related Distributed Control and Information System (N-DCIS) electrical loads. Selected N-DCIS electrical loads are automatically de-energized upon receipt of a CRHA high temperature initiation signal (indicating failure of the redundant nonsafety-related recirculation AHUs). During

BASES

BACKGROUND (continued)

operation of the EFU, the standby selected EFU is automatically started upon receipt of a EFU outlet high radiation or EFU low flow initiation signal (indicating failure of the selected primary EFU filters or fans to operate). Controls to manually isolate the CRHA and to manually actuate CRHAVS following indication of a radiological event (indicative of conditions that could result in radiation exposure to CRHA occupants) are provided.

CRHAVS operation in maintaining CRHA habitability is discussed in Section 6.4 and Section 9.4.1 (Refs. 1 and 2, respectively).

Technical Specifications are required by 10 CFR 50.36 to contain Limiting Safety System Settings (LSSS) defined by the regulation as "...settings for automatic protective devices related to those variables having significant safety functions." Where LSSS is specified for a variable on which a Safety Limit (SL) has been placed, the setting must be chosen such that automatic protective action will correct the abnormal situation before a SL is exceeded. The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. Where LSSS is specified for a variable having a significant safety function but which does not protect SLs, the setting must be chosen such that automatic protective actions will initiate consistent with the design basis. The Design Limit is the limit of the process variable at which a safety action is initiated to ensure that these automatic protective devices will perform their specified safety function.

The actual settings for automatic protective devices must be chosen to be more conservative than the Analytical/Design Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The methodology for determining the actual settings, and the required tolerances to maintain these settings conservative to the Analytical/Design Limits, including the requirements for determining that the channel is OPERABLE, are defined in the Setpoint Control Program (SCP), in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)."

BASES

BACKGROUND (continued)

The Limiting Trip Setpoint (LTSP) is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical/Design Limit and thus ensuring that the SL would not be exceeded (i.e., for Analytical Limits), or that automatic protective actions occur consistent with the design basis (i.e., for Design Limits). As such, the LTSP accounts for process and primary element measurement errors, and uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., accuracy), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the LTSP ensures that SLs are not exceeded and that automatic protective devices will perform their specified safety function. As such, the LTSP meets the definition of an LSSS. The nominal trip setpoint to which the setpoint is reset after calibration is the $NTSP_F$, which is more conservative than the LTSP and has margin to assure that the Allowable Value is not exceeded during calibration.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and that automatic protective actions will initiate consistent with the design basis. Therefore, the LTSP is the LSSS as defined by 10 CFR 50.36. However, use of the LTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as-found" value of a protective device setting during a Surveillance.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value is specified in the SCP, as required by Specification 5.5.11, in order to define OPERABILITY of the devices and is designated as the Allowable Value, which is the least conservative value of the as-found setpoint that a channel can have during CHANNEL CALIBRATION. The LTSP, $NTSP_F$, Allowable Value, "as-found" tolerance, and "as-left" tolerance, and the methodology for calculating the "as-left" and "as-found" tolerances will be maintained in the SCP, as required by Specification 5.5.11.

BASES

BACKGROUND (continued)

The Allowable Value is the least conservative value that the setpoint of the channel can have when tested such that a channel is OPERABLE if the setpoint is found conservative with respect to the Allowable Value during the CHANNEL CALIBRATION. Note that, although a channel is OPERABLE under these circumstances, the setpoint must be left adjusted to a value within the established "as-left" tolerance of the $NTSP_F$ and confirmed to be operating within the statistical allowances of the uncertainty terms assigned in the setpoint calculation. As such, the Allowable Value differs from the $NTSP_F$ by an amount equal to or greater than the "as-found" tolerance value. In this manner, the actual setting of the device will ensure that a SL is not exceeded or that automatic protective actions will initiate consistent with the design basis at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to be non-conservative with respect to the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

The Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System controls the initiation signals and logic for CRHA isolation, CRHAVS actuation, and N-DCIS electrical load de-energization. SSLC/ESF is a four division, separated protection logic system designed to provide a very high degree of assurance to both ensure CRHA isolation, CRHAVS actuation, and N-DCIS electrical load de-energization when required, and prevent inadvertent isolation, actuation, and de-energization. The input and output trip determinations for all CRHAVS functions are based upon a two-out-of-four logic arrangement. Each division of SSLC/ESF is configured such that all functions (e.g., the digital trip module (DTM) function and voter logic unit (VLU) function) are implemented in triply redundant processors to support the requirement that single divisional failures cannot result in inadvertent actuation.

Four separate instrument channels are used to monitor CRHAVS initiation parameters. Signals from sensors are multiplexed at the divisional level and triply redundant sensor data is then transmitted to the PRMS and SSLC/ESF triply redundant DTM function for setpoint comparison. The output of each divisional DTM (a trip/no-trip condition) is routed to all four divisional triply redundant VLU functions such that

BASES

BACKGROUND (continued)	each divisional VLU function receives input from each of the four divisional DTM functions. For maintenance purposes and added reliability, each DTM function has a division of sensors bypass such that all instruments in that division will be bypassed in the trip logic at the VLU functions. Thus, each VLU function will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time. The processed trip signal from its own division and trip signals from the other three divisions are processed in the triply redundant VLU function for two-out-of-four voting. The load driver arrangement for actuation of the CRHA isolation dampers, CRHAVS fans and dampers, and N-DCIS electrical load breakers are such that an actuation signal from two divisions of CRHA isolation, CRHAVS actuation, and N-DCIS electrical load de-energization logic are required to actuate each damper, fan, or breaker. Although an actuation signal from any two divisions provides the start signal for all four EFU fans with their associated dampers, the SSLC/ESF logic allows only one designated EFU fan to start in the designated primary EFU. This Specification provides OPERABILITY requirements for the CRHA isolation, CRHAVS actuation, and N-DCIS electrical load de-energization instrumentation from the input variable sensors through the DTM function. OPERABILITY requirements for the CRHA isolation, CRHAVS actuation, and N-DCIS electrical load de-energization instrumentation circuitry consisting of VLU functions and load drivers are provided by LCO 3.3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Actuation." OPERABILITY requirements for the actuated components are addressed in LCO 3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)."
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The ability of the CRHAVS to maintain habitability of the CRHA is an explicit assumption for the safety analyses presented in Chapter 6 and Chapter 15, (Refs. 1 and 3, respectively). The isolation mode of the CRHAVS is assumed to operate following a design basis accident (DBA). The radiological dose to control room personnel as a result of

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

various DBAs is summarized in Reference 3. No single active failure will result in a loss of the system design function.

CRHAVS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the CRHAVS instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. Each Function must have the required number of OPERABLE channels, with their setpoints in accordance with the SCP, where appropriate.

$NTSP_F$s are specified in the SCP, as required by Specification 5.5.11. The $NTSP_F$s are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

The individual Functions are required to be OPERABLE in MODES 1, 2, 3, and 4 to maintain habitability of the control room following a DBA, since the DBA could lead to a fission product release.

In MODES 5 and 6, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Functions listed in Table 3.3.7.1-1 are not required to be OPERABLE in MODES 5 or 6, except for other situations under which significant radioactive releases can be postulated, i.e., during operations with a potential for draining the reactor vessel (OPDRVs).

Although there are four channels of CRHAVS instrumentation for each function, only three channels of CRHAVS instrumentation for each function required to be OPERABLE. The three required channels are those channels associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating," and LCO 3.8.7, "Distribution Systems – Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE CRHAVS instrumentation channels, and because each CRHAVS instrumentation division is associated with and receives power from only one of the four electrical divisions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The specific Applicable Safety Analyses, LCO and Applicability discussions are listed below on a Function-by-Function basis.

1. Control Room Air Intake Radiation – High-High

Radiation monitors for the Control Building Air Intake consist of four redundant channels to monitor the air intake to the building. Each radiation channel consists of a gamma sensitive detector and a radiation monitor that is located in the main control room.

The Control Room Air Intake Radiation - High-High Allowable Value is chosen to ensure the control room is isolated prior to exceeding the 10 CFR 50 Appendix A GDC 19 requirements.

Three channels of Control Room Air Intake Radiation - High-High Function are required to be OPERABLE to ensure no single instrument failure will preclude CRHA isolation and actuation of CRHAVS in the emergency filtration mode of operation.

2. Extended Loss of AC Power

If the nonsafety-related main air supply units are de-energized due to a loss of AC power, the SSLC/ESF provides an initiation signal as a conservative measure assuming a radiological release.

Three channels of Extended Loss of AC Power Function are required to be OPERABLE to ensure no single instrument failure will preclude CRHA isolation and actuation of CRHAVS in the emergency filtration mode of operation.

3. EFU Discharge Flow – Low (primary train)

Flow detectors for the EFU outlets consist of four redundant channels on each filter train to monitor the flow rate of filtered air being supplied to the Control Room Habitability Area. When low flow is detected and has not been corrected by start of the operating train's standby EFU fan, then the standby EFU train automatically starts to continue the emergency filtration mode. Any two-out-of-four channel trips result in the automatic shutdown of the in-service EFU and automatic start-up of the standby EFU.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The EFU Discharge Flow - Low Allowable Value is chosen to ensure swap over of the EFU such that the control room remains pressurized.

Three channels of EFU Discharge Flow - Low Function for the selected primary CRHAVS train are required to be OPERABLE to ensure no single instrument failure will preclude actuation of the standby CRHAVS train in the emergency filtration mode of operation.

4. EFU Outlet Radiation – High-High (primary train)

Radiation monitors for the EFU outlets consist of four redundant channels on each filter train to monitor the filtered air to the Control Room Habitability Area. Each radiation channel consists of a gamma sensitive detector and a radiation monitor that is located in the main control room. Any two-out-of-four channel trips result in the automatic shutdown of the in-service EFU and automatic start-up of the standby EFU.

The EFU Outlet Radiation – High-High Allowable Value is chosen to ensure swap over of the EFU without exceeding the 10 CFR 50 Appendix A GDC 19 requirements.

Three channels of EFU Outlet Radiation – High-High Function for the selected primary CRHAVS train are required to be OPERABLE to ensure no single instrument failure will preclude actuation of the standby CRHAVS train in the emergency filtration mode of operation.

ACTIONS

The ACTIONS have been modified by a Note to permit separate Condition entry for each CRHAVS instrumentation channel. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable CRHAVS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable CRHAVS instrumentation channel.

BASES

ACTIONS (continued)

A.1

With one or more Functions with one required channel inoperable, the required channel must be restored to Operable status within 12 hours.

The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide actuation signals, the redundancy of the CRHAVS instrumentation design, and the low probability of an event requiring CRHAVS actuation during this period.

However, this out of service time is only acceptable provided the associated Function still maintains CRHAVS actuation capability (refer to Required Actions B.1 Bases).

Alternatively, if the instrumentation division can not be restored to OPERABLE status, Condition B must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1

Required Action B.1 directs entry into the appropriate Condition referenced in Table 3.3.7.1-1 if the Required Action and Completion Time of Condition A is not met or if multiple, inoperable, untripped required channels for the same Function result in the Function not maintaining CRHAVS actuation capability. A Function is considered to be maintaining CRHAVS actuation capability when sufficient channels are OPERABLE or in trip such that the CRHAVS logic will generate an initiation signal from the given Function on a valid signal. The applicable Condition specified in the Table is Function dependent.

C.1.1, C.1.2, and C.2

If the required channel(s) is not restored to OPERABLE status within the allowed Completion Time or if CRHAVS actuation capability for the Function is not maintained, the associated feature(s) may be incapable of performing the intended function.

Required Action C.1.1 and Required Action C.1.2 require manual isolation of the CRHA boundary and placing an OPERABLE CRHAVS train in the isolation mode, respectively, which accomplishes the safety function by ensuring

ACTIONS (continued)

radiological protection of the occupants within the CRHA boundary.

Alternatively, Required Action C.2 requires declaring the CRHAVS trains inoperable in accordance with LCO 3.7.2. Declaring the CRHAVS trains inoperable is acceptable, since the Required Actions of LCO 3.7.2 provide appropriate actions for the inoperable components

D.1

If the required channel(s) is not restored to OPERABLE status within the allowed Completion Time or if CRHAVS actuation capability for the Function is not maintained, the signal(s) to automatically swap CRHAVS trains may be incapable of performing the intended function and the affected CRHAVS train (the standby train) must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

The SRs are modified by a Note. The Note directs the reader to Table 3.3.7.1-1 to determine the correct SRs to perform for each CRHAVS Function.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks and communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK every 12 hours supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks and communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the CRHAVS instrumentation channels.

SR 3.3.7.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the NTSPF within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint.

SR 3.3.7.1.4

This SR ensures that the individual required channel response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain

BASES

SURVEILLANCE REQUIREMENTS (continued)

the CRHAVS RESPONSE TIME. CRHAVS RESPONSE TIME acceptance criteria are included in Reference 4.

CRHAVS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the isolation instrumentation from the input variable sensors through the DTM function.

This test overlaps the testing required by SR 3.3.7.2.2 to ensure complete testing of instrumentation channels and actuation circuitry.

A Note to the Surveillance states that the radiation detectors may be excluded from CRHAVS RESPONSE TIME testing. This Note is necessary because of the difficulty of generating an appropriate detector input signal and because the principles of detector operation virtually ensure an instantaneous response time. Response Time for radiation detection channels shall be measured from detector output or the input of the first electronic component in the channel.

STD COL 16.0-1-A 3.3.7.1-3

CRHAVS RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three channels. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Section 6.4.
2. Section 9.4.1.
3. Section 15.4.
4. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.7.2 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Actuation

BASES

BACKGROUND

NAPS COL 16.0-1-A 3.3.7.2-1

The purpose of the CRHAVS actuation logic is to initiate appropriate actions to ensure the CRHAVS and control room habitability area (CRHA) boundary provide a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity. The equipment involved with CRHAVS is described in the Bases for LCO 3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)."

This specification addresses OPERABILITY of the CRHAVS actuation circuitry from the outputs of the Digital Trip Module (DTM) functions through the voter logic unit (VLU) functions and the load drivers (LDs) associated with the CRHAVS. Operability requirements associated with the CRHAVS instrumentation channels are provided in LCO 3.3.7.1, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Instrumentation." Operability requirements for actuated components (i.e., dampers and valves) are addressed in LCO 3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)."

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CRHAVS to maintain habitability of the CRHA is an explicit assumption for the safety analyses presented in Chapter 6 and Chapter 15, (Refs. 1 and 2, respectively). The isolation mode of the CRHAVS is assumed to operate following a design basis accident (DBA). The radiological dose to control room occupants as a result of various DBAs is summarized in Reference 2. No single active failure will result in a loss of the system design function.

CRHAVS actuation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	CRHAVS actuation supports OPERABILITY of the CRHAVS Instrumentation, LCO 3.3.7.1, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Instrumentation," and therefore is required to be OPERABLE. This Specification addresses OPERABILITY of the CRHAVS actuation circuitry from the outputs of the DTM functions through the LDs, which covers the VLU functions and the LDs associated with the CRHA isolation dampers, CRHAVS Emergency Filtration Unit (EFU) fans and isolation dampers, and Nonsafety-Related Distributed Control and Information System (N-DCIS) electrical load breakers, and other nonsafety-related electrical loads in the CRHA. Although there are four divisions of CRHAVS actuation, only three CRHAVS actuation divisions are required to be OPERABLE. The three required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating," and LCO 3.8.7, "Distribution Systems – Shutdown." This is acceptable because the single-failure criterion is met with three OPERABLE CRHAVS actuation divisions, and because each CRHAVS actuation division is associated with and receives power from only one of the four electrical divisions. In MODES 1, 2, 3, and 4 the CRHAVS must be OPERABLE to maintain habitability of the control room following a DBA, since the DBA could lead to a fission-product release. In MODES 5 and 6, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CRHAVS OPERABLE is not required in MODE 5 or 6, except for other situations under which significant radioactive releases can be postulated, i.e., during operations with a potential for draining the reactor vessel (OPDRVs).
ACTIONS	<u>A.1</u> Condition A exists when one required CRHAVS actuation division is inoperable. In this Condition, CRHAVS actuation still maintains actuation trip capability, but cannot accommodate a single failure. The 12-hour Completion Time is acceptable based on engineering judgment considering the diversity of sensors available to provide trip signals, the redundancy of the CRHAVS actuation design, and the low

BASES

ACTIONS (continued)

probability of an event requiring CRHAVS actuation during this period. However, this out of service time is only acceptable provided the associated Function still maintains CRHAVS actuation capability (refer to Required Actions B.1.1, B.1.2, B.1.3, and B.2 Bases).

Alternatively, if it is not desired to restore the required actuation division to OPERABLE status, Condition B must be entered and its Required Action taken when the Completion Time of Required Action A.1 expires.

B.1.1, B.1.2, B.1.3, and B.2

With the Required Actions and associated Completion Times of Condition A or B are not met, or two or more required actuation divisions are inoperable, the associated feature(s) may be incapable of performing the intended function. CRHAVS automatic actuation capability is considered to be maintained when sufficient actuation divisions are OPERABLE or in trip such that the CRHAVS logic will generate an actuation signal on a valid signal.

Required Action B.1.1 and Required Action B.1.2 require manual isolation of the CRHA boundary and placing an OPERABLE CRHAVS train in the isolation mode, respectively, which accomplishes the safety function of the inoperable channel by ensuring radiological protection of the occupants within the CRHA boundary. Required Action B.1.3 requires declaring the CRHAVS train that is not placed in service inoperable since a failure in the actuation division may affect its ability to initiate upon a failure of the in-service train. Declaring the remaining CRHAVS train inoperable is acceptable, since the Required Actions of LCO 3.7.2 provide appropriate actions for the inoperable train.

Alternatively, Required Action B.2 requires declaring the affected actuation device(s) inoperable in accordance with LCO 3.7.2. Declaring the affected actuation device(s) inoperable is acceptable, since the Required Actions of LCO 3.7.2 provide appropriate actions for the inoperable components.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.1

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required CRHAVS logic for a specific division.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.3.7.2.2

This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the CRHAVS RESPONSE TIME. CRHAVS RESPONSE TIME acceptance criteria are included in Reference 3.

CRHAVS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. This test encompasses the isolation actuation circuitry consisting of timers, VLU functions, and load drivers. This test overlaps the testing required by SR 3.3.7.1.4 to ensure complete testing of instrumentation channels and actuation divisions.

STD COL 16.0-1-A 3.3.7.2-2

CRHAVS RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS for three divisions. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that the channels associated with each division are alternately tested. The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. Section 6.4.
2. Section 15.4.
3. Section 15.2.

B 3.3 INSTRUMENTATION

B 3.3.8.1 Diverse Protection System (DPS)

BASES

BACKGROUND

The DPS comprises a portion of the diverse instrumentation and control systems that are part of the diversity and defense-in-depth strategy.

The DPS functions are implemented in the Nonsafety-Related Distributed Control and Information System (N-DCIS) as a highly reliable, triple redundant control system whose sensors, hardware and software are diverse from their counterparts on any of the safety-related instrumentation and control systems. The DPS is a nonsafety-related, triple redundant system powered by redundant nonsafety-related load group power supplies.

DPS provides a set of initiation logics that provide a diverse means to initiate certain engineered safety feature (ESF) functions using sensors, hardware and software that are separate from, and independent of, the primary ESF systems. The ESF Functions include core cooling provided by the Gravity-Driven Cooling System (GDCS) and the Automatic Depressurization System (ADS) function using safety relief valves (SRVs) and depressurization valves (DPVs). The initiating logic is based on Reactor Pressure Vessel Level – Low, Level 1.

The initiation logic is "energize to actuate," similar to that described in the Bases for LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Emergency Core Cooling System (ECCS) Actuation." The diverse ECCS automatic initiation signal is based on two-out-of-four coincident logic processed by triple redundant processors. If the DPS ECCS initiation signal persists for 10 seconds, the logic seals in and a DPS ECCS start signal is initiated. Manual initiation requires operation of two switches, with each switch requiring two distinct operator actions. The manual initiation signal is based on two-out-of-two coincident logic processed by triple redundant processors. A coincident logic trip decision is required from two-out-of-three processors to generate the start signal. Series discrete output switches independently process the two-out-of-three voted start signal. A valid initiation signal from all series output switches is required to generate diverse actuation.

BACKGROUND (continued)

For the ADS SRV opening function, three of the four solenoids on each SRV are powered by three of the four divisional safety-related power sources in the Safety System Logic and Control Engineered Safety Features (SSLC/ESF) ADS described in the Bases for LCO 3.3.5.1 and LCO 3.3.5.2. A fourth solenoid on each SRV is powered by the nonsafety-related load group, with the trip logic controlled by DPS. All ten SRVs in the ADS are controlled by the DPS through the fourth solenoid on each valve.

For the ADS DPV opening function, one of the four squib initiators on each DPV is controlled by and connected to the nonsafety-related DPS logic. The other three solenoids are controlled by the SSLC/ESF ADS logic described in the Bases for LCO 3.3.5.1 and LCO 3.3.5.2. It takes three simultaneous DPS trip signals in a triple redundant logic path to initiate the squib valve opening.

The logic application for the GDCS squib valves from the DPS is similar to that of the DPV logic application described above. For the GDCS squib valve-opening function, one of the four squib initiators on each GDCS valve is controlled by and connected to the nonsafety-related DPS logic. The DPS logic requires three simultaneous GDCS trip initiation signals to initiate a GDCS squib valve opening.

The DPS also performs selected containment isolation functions as part of the diverse ESF function using two-out-of-four sensor logic and two-out-of-three processing logic. The containment isolation functions performed by DPS include closure of the Reactor Water Cleanup and Shutdown Cooling (RWCU/SDC) isolation valves on Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow - High.

The DPS also opens pool cross-connect valves between the equipment storage pool and the Isolation Condenser/Passive Containment Cooling System (IC/PCCS) expansion pools when a low level condition is detected in the IC/PCCS inner expansion pool to which the valves are connected. Each IC/PCCS pool is connected to the equipment storage pool by two cross-connect valves in parallel where one valve is a pneumatic operated valve with an accumulator and the other is a squib valve. Each expansion pool-to-equipment pool cross-connect squib valve is equipped with four squib initiators. The expansion pool-to-equipment pool cross-connect pneumatic valves are equipped with four

BASES

BACKGROUND (continued)	solenoid valves (i.e., initiators). A signal to any of the four initiators will actuate the valve. One of the four initiators on each valve is actuated by DPS.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The DPS Functions are required to provide a diverse capability to actuate the specified safety-related equipment based on risk importance (Ref. 1). The DPS Functions are not credited for mitigating accidents in the safety analyses (Ref. 2). The DPS satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Each Function must have its setpoint in accordance with the Setpoint Control Program (SCP), where appropriate. The actual setpoint is calibrated consistent with the SCP.

Nominal Trip Setpoints ($NTSP_F$s) are specified in the Setpoint Control Program (SCP), as required by Specification 5.5.11. The $NTSP_F$s are selected to ensure the actual setpoints are conservative with respect to the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the $NTSP_F$, but conservative with respect to its Allowable Value, is acceptable. A Function is inoperable if its actual trip setpoint is non-conservative with respect to its required Allowable Value.

$NTSP_F$s are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, an actuation signal is generated. For those limiting safety system settings (LSSS) related to variable protecting Safety Limits (SLs), the Analytical Limits are derived from the limiting values of the process parameters obtained from the safety analysis. For those LSSS related to variables having significant safety functions but which do not protect SLs, the Design Limits are those settings that must initiate automatic protective actions consistent with the design basis. The Allowable Values are derived from the Analytical/Design Limits, corrected for calibration, process and some of the instrument errors. The $NTSP_F$s are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

tolerances, instrument drift and severe environment errors (for instrumentation that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

1.a, 2.a <u>Reactor Vessel Level – Low, Level 1</u>

Automatic actuation of ADS (consisting of the SRVs and DPVs) and GDCS injection occurs upon detection of Reactor Vessel Level – Low, Level 1. Reactor Vessel water level is detected by four wide range water level sensors that are different from those used for the SSLC/ESF wide range level sensors. Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result.

The Reactor Vessel Level – Low, Level 1 Function is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the assumptions in Reference 1.

1.b, 2.b <u>Drywell Pressure – High (Manual Actuation)</u>

Manual controls are provided for ADS (consisting of the SRVs and DPVs) and GDCS injection initiation upon detection of high drywell pressure sustained for 60 minutes. This control is provided to mitigate small and medium break LOCA scenarios that do not result in GDCS and ADS initiation from low RPV water level. This Function also requires OPERABILITY of DPS indication of the high drywell pressure condition.

The Drywell Pressure – High (Manual Actuation) Function is required to be OPERABLE in MODES 1, 2, 3, and 4 consistent with the assumptions in Reference 1.

3.a <u>Reactor Vessel Level – Low (Manual Actuation)</u>

Manual controls are provided for initiation of the GDCS equalizing lines upon detection of low reactor vessel water level. Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. This Function also requires OPERABILITY of DPS indication of the low water level condition.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Reactor Vessel Level – Low (Manual Actuation) Function is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the assumptions in Reference 1.

4.a <u>Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow – High</u>

Automatic isolation of RWCU/SDC occurs upon detection of Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow – High. Isolation of the RWCU System is initiated when RWCU/SDC System Differential Mass Flow – High is sensed to prevent exceeding off-site doses.

The function of the RWCU/SDC isolation valves, in combination with other accident mitigation systems, is to limit fission product release during a postulated Design Bases Accident (DBA).

The Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow – High Function is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the assumptions in Reference 1.

5.a <u>Isolation Condenser/Passive Containment Cooling System Pool Level – Low</u>

Automatic actuation of the IC/PCCS expansion pool-to-equipment pool cross-connect occurs upon detection of Isolation Condenser/Passive Containment Cooling System Pool Level – Low in the associated IC/PCCS inner expansion pool. Actuation of the IC/PCCS expansion pool-to-equipment pool cross-connect ensures a sufficient quantity of water is available for decay heat removal in the event of a design basis accident.

The Isolation Condenser/Passive Containment Cooling System Pool Level – Low Function is required to be OPERABLE in MODES 1, 2, 3, and 4, consistent with the assumptions in Reference 1.

ACTIONS

A Note has been provided to modify the ACTIONS related to the DPS Functions. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition

ACTIONS (continued)

continue to apply for each additional failure, with Completion Times based on initial entry into the condition. However, the Required Actions for inoperable DPS Functions provide appropriate compensatory measures for separate inoperable Functions. As such, a Note has been provided which allows separate Condition entry for each inoperable DPS Function.

A.1

In this Condition, required safety-related initiators will actuate the components assumed in the design basis LOCA analysis in Reference 2 concurrent with any additional single failure. However, design features intended to mitigate digital protection system common mode failures may not be available.

In this Condition, the inoperable Function must be restored to OPERABLE status within 30 days. This Completion Time is acceptable because the required safety-related initiators will actuate the minimum number of components required to respond to the design basis LOCA concurrent with any additional single failure.

B.1 and B.2

With the Required Action and associated Completion Time of Condition A not met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of DPS has not occurred. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A CHANNEL CHECK will detect gross DPS failure; thus, it is key to verifying the DPS continues to operate properly between each CHANNEL CALIBRATION.

The Frequency is based upon operating experience that demonstrates failure of the DPS components is rare. The CHANNEL CHECKS every 12 hours supplement less formal, but more frequent checks of DPS during normal operational use of the displays associated with the Functions required to be OPERABLE by the LCO.

SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on the DPS to ensure that the entire DPS will perform the intended Functions. The associated controllers, displays, monitoring and input/output (I/O) communication interfaces continuously function during normal power operation. Abnormal operation of these components is detected and alarmed. In addition, the associated controllers are equipped with on-line diagnostic capabilities for cyclically monitoring the functionality of I/O signals, buses, power supplies, processors, and inter-processor communications.

The 31-day Frequency is based on the reliability of the DPS.

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the DPS responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the DPS adjusted to the $NTSP_F$ within the "as-left" tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the DPS logic. LOGIC SYSTEM FUNCTIONAL tests are conducted on a 24-month Frequency. The testing in LCO 3.3.6.4, "Isolation Actuation," LCO 3.6.1.3, "Containment Isolation Valves (CIVs)," LCO 3.5.2, "Gravity-Driven Cooling System (GDCS) – Operating," and

BASES

SURVEILLANCE REQUIREMENTS (continued)	LCO 3.7.1, "Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools," overlaps this Surveillance to provide complete testing of the assumed safety function. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.
REFERENCES	1. Chapter 19. 2. Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Safety Relief Valves (SRVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of SRVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). The ESBWR steam relief capacity is designed to satisfy both ASME Code Service Level B (upset) overpressure protection, and Service Level C (emergency) design service limits (Ref. 2). This LCO addresses only those requirements for operability of the vessel overpressure protection that satisfy the Service Level B pressure limits.

The SRVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. In the safety mode, the direct action of the steam pressure in the main steam lines will act against a spring-loaded disk that will pop open when the valve inlet pressure exceeds the spring force and the frictional forces acting against the inlet steam pressure at the main or pilot disk.

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe Service Level B pressure transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 3). The analysis results demonstrate that the design capacity of one SRV is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure, i.e., 110% x 8.62 MPaG (1250 psig) = 9.48 MPaG (1375 psig). This LCO helps to ensure that the acceptance limit of 9.48 MPaG (1375 psig) is met during the design basis event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 4 discusses additional events that are expected to actuate the SRVs.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Safety relief valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The results of the overpressure analysis provided in Reference 3 demonstrate that one SRV is required to function in the safety mode to meet ASME overpressure protection. Therefore, to satisfy the design basis overpressure event (including provision for single failure), two SRVs are required to be OPERABLE. The requirements of this LCO are applicable only to the capability of the SRVs to mechanically open in the safety mode to relieve excess pressure. The SRV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure, i.e., 8.62 MPaG (1250 psig), and the highest safety valve is set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 assume that the SRV setpoints are at conservatively high values above the nominal setpoints to account for initial setpoint errors and any setpoint drift that might occur during operation. Operation with fewer valves OPERABLE than specified, or with setpoints greater than specified, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.
APPLICABILITY	In MODES 1, 2, 3 and 4, the specified number of SRVs must be OPERABLE because there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. In MODE 5, reactor pressure is low enough that the overpressure limit is not likely to be approached by assumed operational transients or accidents. In MODE 6, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. Therefore, the SRV function is not required by LCO 3.4.1 during these conditions.

BASES

ACTIONS

A.1

With the safety mode of one required SRV inoperable, the remaining operable SRV is capable of providing the necessary overpressure protection. However, the overall reliability of the pressure relief system is reduced because additional failure of the remaining OPERABLE SRV could result in failure to adequately relieve pressure during an overpressure event. For this reason, continued operation is permitted for a limited time only.

The 14-day Completion Time to restore the inoperable required SRV to OPERABLE status is based on the relief capability of the remaining SRV, the low probability of an event requiring SRV actuation, and a reasonable time to complete the Required Action.

B.1

If the Required Action and associated Completion Time of Condition A cannot be met, or with less than the minimum number of required SRVs OPERABLE, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status the plant must be brought to at least MODE 3 within 12 hours and MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This Surveillance demonstrates that the required SRVs will open at the pressures assumed in the safety analysis of Reference 3.

The demonstration of the SRV safety mode lift settings is a bench test and must be performed during shutdown. The SRV setpoint is $\pm 3\%$ for OPERABILITY and the valves are reset to $\pm 1\%$ during the Surveillance.

The Frequency of this SR is in accordance with the Inservice Testing Program.

BASES

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. Section 5.2.2.
3. Section 15.5.1.
4. Section 15.5.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded unless applicable codes permit flanged or threaded joints.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE.

This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c) and GDC 55 of 10 CFR 50, Appendix A (Ref. 1, 2, and 3). 10 CFR 50, Appendix A, GDC 30 (Ref. 4), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 5) describes acceptable methods for selecting Leakage Detection Systems.

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leak tight. Leakage from these systems should be detected and isolated from the primary containment atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release

BASES

BACKGROUND (continued)	assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss-of-coolant accident.
APPLICABLE SAFETY ANALYSES	The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly. The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The allowable LEAKAGE limits are based on the predicted and experimentally determined behavior of cracks in pipes, the ability to makeup to the RCS, the normally expected background leakage due to equipment design, and the detection capability of the various sensors and instruments. No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity. RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	RCS operational LEAKAGE shall be limited to: a. <u>Pressure Boundary LEAKAGE</u> No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets are not pressure boundary LEAKAGE. b. <u>Unidentified LEAKAGE</u> The unidentified LEAKAGE limit is based on a reasonable minimum detectable amount that the drywell air monitoring, drywell sump level monitoring, and drywell air cooler

BASES

LCO (continued)

condensate flow rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

APPLICABILITY

In MODES 1, 2, 3, and 4, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 5 and 6, compliance with the RCS operational LEAKAGE limits is not required because the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

ACTIONS

A.1

With RCS LEAKAGE greater than the limits for reasons other than pressure boundary LEAKAGE, actions must be taken to reduce LEAKAGE to within limits. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours are allowed to verify the source and reduce the LEAKAGE rates before the reactor must be shut down. A change in unidentified LEAKAGE that has been identified and quantified may be reclassified and considered as identified LEAKAGE. However, the total LEAKAGE limit would remain unchanged. The 4-hour Completion Time is needed to properly verify the source and reduce the LEAKAGE before the reactor must be shut down.

B.1 and B.2

If any Required Action and associated Completion Time of Condition A is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours, and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based

BASES

ACTIONS (continued)

on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.3.4.1, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference 5. In conjunction with alarms and other administrative controls, a 12-hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. 6).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55.
4. 10 CFR 50, Appendix A, Section IV, GDC 30.
5. Regulatory Guide 1.45.
6. Generic Letter 88-01, Supplement 1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Specific Activity

BASES

BACKGROUND	During circulation, the reactor coolant acquires radioactive materials due to release of fission-products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during an accident could send radioactive materials into the environment. Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure, in the event of a release of any radioactive material to the environment during an accident, radiation doses are maintained within the limits of 10 CFR 52.47(a)(2)(iv) (Ref. 1). This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2-hour radiation dose to an individual at the site boundary to within the 10 CFR 52.47(a)(2)(iv) limit.
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving radioactive material in the primary coolant are presented in Reference 2. The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a: 1. Main steam line break (MSLB) outside containment 2. Feedwater line break (FWLB) outside containment 3. Small line break outside containment, or 4. Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System line break outside containment. The RWCU/SDC System line break outside containment release is the bounding accident with respect to offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2-hour Total Effective Dose

BASES

APPLICABLE SAFETY ANALYSES (continued)	Equivalent (TEDE) doses at the site boundary, resulting from an RWCU/SDC System line break outside containment during steady state operations, will not exceed the dose guidelines of Regulatory Guide 1.183 (Ref. 3). The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site. RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The specific iodine activity is limited to ≤ 7400 Bq/gm (0.2 μCi/gm) DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis is not exceeded, so any release of radioactivity to the environment during an RWCU/SDC System line break outside containment is less than the Regulatory Guide 1.183 limits.
APPLICABILITY	In MODE 1, and MODES 2, 3, and 4, limits on the primary coolant radioactivity are applicable because there is an escape path for release of radioactive material from the primary coolant to the environment in the event of line breaks outside of primary containment. In MODES 5 and 6, no limits are required because the reactor is not pressurized and the potential for leakage is reduced.
ACTIONS	<u>A.1 and A.2</u> When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 148,000 Bq/gm (4.0 μCi/gm), samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 48-hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

BASES

ACTIONS (continued)

B.1, B.2, and B.3

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 7400 Bq/gm (0.2 μCi/gm) within 48 hours, or if at any time it is > 148,000 Bq/gm (4.0 μCi/gm), it must be determined at least every 4 hours.

The plant must be brought to MODE 3 within 12 hours and to MODE 5 within 36 hours. These actions reduce the potential for leakage by reducing RCS pressure and core thermal energy. In MODE 5, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The allowed Completion Times for Required Actions B.2 and B.3 for bringing the plant to MODES 3 and 5 are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7-day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 52.47(a)(2)(iv).
2. Section 15.4.
3. Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Plants," July 2000.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

STD COL 16.0-1-A 3.4.4-1

The PTLR contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic testing, and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides limits for both heatup and criticality.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component of most concern in regard to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The actual shift in the Reference Temperature, Nil-Ductility Transition (RT_{NDT}) of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and 10 CFR 50, Appendix H (Ref. 4).

BASES

BACKGROUND (continued)

The operating P/T limit curves will be adjusted as necessary, based on the evaluation findings and the recommendations of Reference 5.

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The criticality limits include the Reference 1 requirement that they be at least 22°C (40°F) above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a non-isolable leak or loss-of-coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate-of-change conditions that might cause undetected flaws to propagate and cause non-ductile failure of the RCPB, a condition that is unanalyzed. Reference 6 establishes the methodology for determining the P/T limits. Because the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves because they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The elements of this LCO are:

a. RCS pressure, temperature, and heatup or cooldown rate are within the limits specified in the PTLR; STD COL 16.0-1-A 3.4.4-1

b. RCS pressure and temperature are within the criticality limits specified in the PTLR, prior to achieving criticality; and STD COL 16.0-1-A 3.4.4-1

c. Reactor vessel flange and the head flange temperatures are within the limits of the PTLR when tensioning reactor vessel head bolting studs. STD COL 16.0-1-A 3.4.4-1

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The temperature rate-of-change limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leak and hydrostatic testing P/T limit curves. Thus, the LCO for the rate-of-change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate-of-change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel

BASES

APPLICABILITY (continued)

metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODES 1, 2, 3,or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30-minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

The 72-hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event-specific stress analyses or inspections. A favorable evaluation must be completed if continued operation beyond the 72 hours is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at

BASES

ACTIONS (continued)

reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by bringing the plant to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, 3, and 4 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 93.3°C (200°F). Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components.

Condition C is modified by a Note requiring Required Action C.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate-of-change limits are specified in hourly increments, 30 minutes permits assessment and correction of minor deviations.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance for heatup, cooldown, or inservice leak and hydrostatic testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR has been modified by a Note that requires this Surveillance to be performed only during system heatup, and cooldown operations and inservice leak and hydrostatic testing.

SR 3.4.4.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.4.3, SR 3.4.4.4, and SR 3.4.4.5

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 5 and MODE 6 and in MODE 5 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

STD COL 16.0-1-A 3.4.4-1

STD COL 16.0-1-A 3.4.4-2

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 5 with RCS temperature ≤ 26.7°C (80°F), 30-minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 5 with RCS temperature ≤ 37.8°C (100°F), monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the limits specified in the PTLR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 30-minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12-hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

3. ASTM E 185-82.

4. 10 CFR 50, Appendix H.

5. Regulatory Guide 1.99, Revision 2, May 1988.

CWR COL 16.0-1-A 3.4.4-3

6. NEDC-33441P, "GE Hitachi Nuclear Energy Methodology for the Development of ESBWR Reactor Pressure Vessel Pressure-Temperature Curves," Revision 6, November 2013.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed initial condition of Design Basis Accidents (DBAs) and is also an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 7.17 MPaG (1040 psig) is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 1 also assumes an initial reactor steam dome pressure for the analysis of DBAs and transients used to determine the limits for fuel cladding integrity MCPR (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"). Reactor steam dome pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified reactor steam dome pressure limit of ≤ 7.17 MPaG (1040 psig) ensures the plant is operated within the assumptions of the transient analyses. Operation above the limit may result in a transient response more severe than analyzed.
APPLICABILITY	In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES the reactor may be generating significant steam and the DBAs and transients are bounding. In MODES 3, 4, 5, and 6, the limit is not applicable because the reactor is shutdown. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

BASES

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15-minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal. If the operator is unable to restore the reactor steam dome pressure to below the limit, then the reactor should be brought to MODE 3 to be within the assumptions of the transient analyses.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

Verification that reactor steam dome pressure is ≤ 7.17 MPaG (1040 psig) ensures that the initial conditions of the DBAs and transients are met. Operating experience has shown the 12-hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

REFERENCES

1. Chapter 15.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Automatic Depressurization System (ADS) - Operating

BASES

BACKGROUND

The ECCS function is provided by the combination of the Gravity-Driven Cooling System (GDCS), the Automatic Depressurization System (ADS), the Standby Liquid Control (SLC) System, and the Isolation Condenser System (ICS). The ECCS is designed to flood the core during a loss-of-coolant accident (LOCA) to provide required core cooling. By providing core cooling following a LOCA, the ECCS, in conjunction with the containment, limits the release of radioactive materials to the environment following a LOCA.

The ADS (Ref. 1) is an integral part of the ECCS because GDCS flow to the RPV requires the RPV to be close to containment pressure. Therefore, the ADS is designed to depressurize the RPV following indication of a LOCA. The ADS consists of eight squib-actuated depressurization valves (DPVs) and the ten Safety Relief valves (SRVs) that have been configured to function as ADS valves. The ten dual function SRVs are pneumatically actuated when functioning as ADS valves using energy stored in nitrogen accumulators.

Each of the eight DPVs is equipped with four squib initiators. A signal to any of the four squib initiators will actuate the DPV. Each of the ten SRVs is equipped with four actuation solenoids (i.e., initiators). A signal to any of the four solenoids will actuate the SRV. Three of the four initiators on each valve are actuated by the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System described in the Bases for LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Emergency Core Cooling System (ECCS) Actuation." The fourth initiator is actuated by the Diverse Protection System (DPS), which is designed to mitigate digital protection system common mode failures.

Power to each of the three safety-related initiators on each ECCS valve is supplied from a different division of the DC and Uninterruptible AC Electrical Power Distribution. As such, at least two of the three safety-related initiators in each ECCS valve will be associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."

BASES

BACKGROUND (continued)	Actuation signals and logic for ADS initiation are described in the Bases of LCO 3.3.5.1. ADS initiation is sequenced beginning with the opening of five SRVs that reduce reactor pressure. The remaining five SRVs open after a short time delay. After another short time delay, the DPVs are staggered opened beginning with a group of three DPVs, followed by consecutive groups of two, two and one DPV with a short time delay between each group. This sequential operation facilitates rapid depressurization while minimizing the amount of water lost because of level swell in the reactor that occurs when pressure is rapidly reduced. The ADS is designed to ensure that no single active component failure will cause inadvertent initiation of ADS or prevent automatic initiation and successful operation of the minimum required ECCS subsystems when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE.
APPLICABLE SAFETY ANALYSES	ADS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents for which ADS operation is required are presented in Reference 2. The required ECCS analyses and assumptions and the results of these analyses are described in References 1 and 2. This LCO ensures that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 3), will be met following a LOCA assuming the worst-case single active component failure in the ECCS: a. Maximum fuel element cladding temperature is ≤ 1204°C (2200°F). b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation. c. Maximum hydrogen generation from zirconium-water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react. d. The core is maintained in a coolable geometry. e. Adequate long-term cooling capability is maintained.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Each break location is analyzed assuming each potential failure to determine the most limiting single failure for the LOCA event to ensure that the remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage. The limiting failures are discussed in Reference 1.

For ADS to support GDCS injection following a small break LOCA, the analysis in Reference 1 assumes the single failure of either one DPV or one SRV. At least three Isolation Condenser loops, two SLC trains, and the minimum required complement of GDCS injection and equalizing lines are assumed to be available during the LOCA.

The ADS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO for ADS requires the OPERABILITY of the following:

a. The ADS function of ten SRVs; and

b. Eight DPVs.

OPERABILITY of each DPV and SRV requires OPERABILITY of the DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6.

OPERABILITY of the ADS function of the SRVs also requires that SRV nitrogen accumulator pressure be within the limit specified by SR 3.5.1.1.

APPLICABILITY

ADS is required to be OPERABLE during MODES 1, 2, 3, and 4 when there is considerable energy in the reactor core and core cooling may be required to prevent fuel damage following a LOCA. ADS requirements for MODES 5 and 6 are determined by the requirements of the GDCS system, which is being supported.

ACTIONS

A.1

This Condition applies when one ADS valve has an inoperable DPS initiator. In this Condition, required safety-related initiators will actuate the minimum number of ADS valves

ACTION (continued)

assumed in the design basis LOCA analysis in Reference 1 concurrent with any additional single failure, including digital protection system common mode failures.

In this Condition, the inoperable DPS initiator must be restored to OPERABLE status the next time the plant is placed in MODE 5 (i.e., prior to entering MODE 2 or MODE 4 from MODE 5). This Completion Time is acceptable because the remaining DPS initiator and the required safety-related initiators will actuate the minimum number of ADS valves required to respond to the design basis LOCA concurrent with any additional single failure.

B.1

This Condition applies when two or more DPS initiators are inoperable. In this Condition, required safety-related initiators will actuate the minimum number of ADS valves assumed in the design basis LOCA analysis in Reference 1 concurrent with any additional single failure. However, design features intended to mitigate the possibility of digital protection system common mode failures are not available.

In this Condition, all but one DPS initiator must be restored to OPERABLE status within 30 days. This Completion Time is acceptable because the required safety-related initiators will actuate the minimum number of ADS valves required to respond to the design basis LOCA concurrent with any additional single failure.

C.1

This Condition applies when one ADS valve (i.e., either one DPV or one SRV) is inoperable for reasons other than Condition A. In this Condition, failure of a second ADS valve could result in less than the minimum required ADS capacity during a design basis LOCA.

In this Condition, the inoperable ADS valve must be restored to OPERABLE status within 14 days. This Completion Time is acceptable based on engineering judgment considering the low probability of a failure of an additional DPV or SRV concurrent with a design basis LOCA during this period.

BASES

ACTION (continued)

D.1 and D.2

This Condition applies when two or more ADS valves (i.e., any combination of DPVs or SRVs) are inoperable for reasons other than Conditions A or B. This Condition also applies when the Required Actions and Completion Times of Conditions A, B, or C are not met. In this Condition, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

This SR requires periodic verification that the supply pressure to SRV accumulators (i.e., High Pressure Nitrogen Supply System (HPNSS)) is greater than or equal to the specified limit. An accumulator on each SRV provides pneumatic pressure for ADS valve actuation. The SRV accumulator capacity is sufficient for one actuation at drywell design pressure following a failure of the gas supply to the accumulator.

The 31-day Frequency is acceptable because HPNSS low pressure alarms provide prompt notification of an abnormal pressure in the HPNSS.

SR 3.5.1.2

This SR requires verification every 31 days of the continuity of the DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems – Operating."

The 31-day Frequency is acceptable because either of the two safety-related initiators in each valve is capable of actuating the associated ADS valve. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each ADS valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity

BASES

SURVEILLANCE REQUIREMENTS (continued)

monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in either division does not disable the ADS valve because the valve will still be opened by the initiator in the other division.

SR 3.5.1.3

This SR requires periodic verification that the ADS function of each SRV actuates on an actual or simulated automatic initiation signal. The ADS function of each SRV is required to actuate automatically to perform its design function. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.5.2 and LCO 3.3.8.1 overlap this SR to provide complete testing of the assumed safety function.

This SR is modified by a Note that excludes SRV valve actuation as a requirement for this SR to be met. This is acceptable because SRVs are tested in accordance with the Inservice Test Program.

The 24-month Frequency for performing this SR is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power. From past operating experience, it is believed that these components will pass the SR when performed once per the 24-month refueling interval.

SR 3.5.1.4

This SR requires periodic verification that the ADS function of each DPV actuates on an actual or simulated automatic initiation signal. The ADS function of each DPV is required to actuate automatically to perform their design functions. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.5.2 overlaps this SR to provide complete testing of the assumed safety function.

This SR is modified by a Note that excludes squib valve actuation as a requirement for this SR to be met. This is acceptable because the design of the squib-actuated valve was selected for this application because of its very high reliability. The OPERABILITY of squib-actuated valves is verified by continuity tests in SR 3.5.1.2 and the Inservice Test Program for squib-actuated valves.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24-month Frequency for performing this SR is based on the need to perform this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed once per the 24-month refueling interval.

REFERENCES

1. Chapter 6.

2. Chapter 15.

3. 10 CFR 50.46.

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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 Gravity-Driven Cooling System (GDCS) - Operating

BASES

BACKGROUND

The ECCS function is provided by the combination of the Gravity-Driven Cooling System (GDCS), the Automatic Depressurization System (ADS), the Standby Liquid Control (SLC) System, and the Isolation Condenser System (ICS). The ECCS is designed to flood the core during a loss-of-coolant accident (LOCA) to provide required core cooling. By providing core cooling following a LOCA, the ECCS, in conjunction with the containment, limits the release of radioactive materials to the environment following a LOCA.

The GDCS (Ref. 1) is divided into three subsystems: the GDCS short-term cooling (injection subsystem); the GDCS long-term cooling (equalizing subsystem); and, the GDCS deluge subsystem. Three GDCS pools, located above the wetwell, at an elevation above the reactor core, contain the water that supports all four GDCS trains for the injection and deluge subsystems.

The GDCS injection subsystem is capable of refilling the RPV following a LOCA after the RPV is depressurized by the ADS. Each of the four injection trains connects to the associated GDCS pool through a single pipe that includes a block valve at the pool. Each of the four injection trains then divides into two branch lines after entering the drywell. The resulting eight injection branch lines each include a check valve, squib-actuated injection valve, and a block valve near the RPV. Each injection branch line provides coolant to the annulus region of the reactor through an RPV nozzle located above the top of active fuel (TAF).

The GDCS equalizing subsystem provides long term post-LOCA water makeup by connecting the annulus region of the reactor to the suppression pool. Each of the four equalizing trains includes a block valve at the suppression pool, a check valve, a squib-actuated equalizing valve, and a block valve at the RPV. The suppression pool is located in the containment with a normal level above the top of the core.

The GDCS deluge subsystem is used to dump water from the GDCS pools to the lower drywell in the event of a severe accident. The deluge subsystem is designed to respond to a severe accident and is not required in any accident analysis in

BASES

BACKGROUND (continued)

Reference 1. Therefore, OPERABILITY of the GDCS deluge subsystems is not required by Technical Specifications and is addressed in licensee controlled documents.

Each of the eight GDCS injection subsystem squib valves is equipped with four squib initiators. A signal to any of the four initiators will actuate the valve. Three of the four initiators on each valve are actuated by the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System described in the Bases for LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation" and LCO 3.3.5.2, "Emergency Core Cooling System (ECCS) Actuation." The fourth initiator is actuated by the Diverse Protection System (DPS), which is designed to mitigate digital protection system common mode failures.

Each of the four GDCS equalizing train squib valves is equipped with four squib initiators. A signal to any of the four initiators will actuate the valve. Three initiators on each valve are actuated by the SSLC/ESF described in the Bases for LCO 3.3.5.1 and LCO 3.3.5.2. The fourth initiator is actuated by the DPS. The equalizing trains are needed for the long term cooling only and are not automatically actuated by the DPS. The DPS initiator is provided only for manual initiation of the equalizing train.

Power to each of the three safety-related initiators on each ECCS valve is supplied from a different division of the DC and Uninterruptible AC Electrical Power Distribution. As such, at least two of the three initiators in each ECCS valve will be associated with divisions required by LCO 3.8.6, "Distribution Systems - Operating."

The GDCS is designed to ensure that no single active component failure will cause inadvertent initiation of GDCS or prevent automatic initiation and successful operation of the minimum required ECCS subsystems when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE.

Although the nominal and bounding containment performance analyses are performed at an initial condition of 46.1°C (115°F) for the GDCS pool water temperature, additional analyses assuming GDCS pool water temperature as high as 65.5°C (150°F) were performed. These analyses demonstrate the relative insensitivity of the calculated peak containment pressure and temperature and reactor pressure

BASES

BACKGROUND (continued)

vessel long-term water level after a DBA for increased GDCS pool water initial temperature. Therefore, monitoring of the GDCS pool temperature is not required.

APPLICABLE SAFETY ANALYSES

GDCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents for which GDCS operation is required are presented in Reference 1. The required ECCS analyses and assumptions and the results of these analyses are described in References 1 and 2.

This LCO ensures that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 3), will be met following a LOCA assuming the worst-case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 1204°C (2200°F).

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation.

c. Maximum hydrogen generation from zirconium-water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

d. The core is maintained in a coolable geometry.

e. Adequate long-term cooling capability is maintained.

Each break location is analyzed assuming each potential failure to determine the most limiting single failure for the LOCA event to ensure that the remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage. Both the injection and equalizing subsystems are designed to ensure that adequate reactor vessel inventory is provided assuming the initiating event is a LOCA in one train and there is a failure of one squib valve to actuate in a second train.

The analysis described in Reference 1 determined that the GDCS injection subsystem is capable of providing the minimum required core cooling following a LOCA initiated by a break in an injection branch line with a concurrent failure of any other injection branch line. The break in an injection

BASES

APPLICABLE SAFETY ANALYSES (continued)	branch line is assumed to disable the injection capability of both injection branch lines in that injection train. Additionally, this analysis determined that the GDCS equalizing trains are capable of providing the minimum required long-term core cooling following a LOCA initiated by a break in an equalizing train with a concurrent failure of any other equalizing train. The GDCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires the OPERABILITY of the following:

a. Eight branch lines of the injection subsystem (i.e., all four injection trains); and

b. Four trains of the equalizing subsystem.

OPERABILITY of each squib-actuated GDCS valve in the injection subsystem and equalizing subsystem requires OPERABILITY of the DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6.

OPERABILITY of each GDCS branch line requires that water level in the associated GDCS pool be within the limit specified by SR 3.5.2.1. Additionally, all GDCS RPV block valves, GDCS pool block valves, and suppression pool block valves must be locked open.

APPLICABILITY

GDCS subsystems are required to be OPERABLE during MODES 1, 2, 3, and 4 when there is considerable energy in the reactor core and core cooling may be required to prevent fuel damage following a LOCA. GDCS requirements for MODES 5 and 6 are specified in LCO 3.5.3, "Gravity-Driven Cooling System (GDCS) - Shutdown."

ACTIONS

A.1

This Condition applies when one or more GDCS subsystems have one inoperable DPS initiator. In this Condition, required safety-related initiators will actuate the minimum number of

ACTIONS (continued)

GDCS valves assumed in the design basis LOCA analysis in Reference 1 concurrent with any additional single failure, including digital protection system common mode failures.

In this Condition, the inoperable DPS initiators must be restored to OPERABLE status the next time the plant is placed in MODE 5 (i.e., prior to entering MODE 2 or MODE 4 from MODE 5). This Completion Time is acceptable because the remaining DPS initiators and the required safety-related initiators will actuate the minimum number of GDCS valves required to respond to the design basis LOCA concurrent with any additional single failure.

B.1

This Condition applies when one or more GDCS subsystems have two or more inoperable DPS initiators. In this Condition, required safety-related initiators will actuate the minimum number of GDCS subsystem valves assumed in the design basis LOCA analysis in Reference 1 concurrent with any additional single failure. However, design features intended to mitigate the possibility of digital protection system common mode failures are not available.

In this Condition, all but one DPS initiator in each GDCS subsystem must be restored to OPERABLE status within 30 days. This Completion Time is acceptable because the required safety-related initiators will actuate the minimum number of GDCS subsystem valves required to respond to the design basis LOCA concurrent with any additional single failure.

C.1

This Condition applies when one GDCS injection subsystem branch line is inoperable for reasons other than Condition A or B. In this Condition, the minimum number of GDCS injection subsystem branch lines required for a design basis LOCA remain OPERABLE. However, failure of a second injection subsystem branch line could result in less than the minimum required GDCS injection capacity assumed in the design basis LOCA analysis in Reference 1.

In this Condition, the inoperable GDCS injection subsystem branch line must be restored to OPERABLE status within 14 days. This Completion Time is acceptable based on

BASES

ACTIONS (continued)

engineering judgment considering the low probability of a failure of an additional GDCS injection subsystem branch line concurrent with a design basis LOCA during this period.

D.1

This Condition applies when one GDCS equalizing train is inoperable for reasons other than Condition A or B. In this Condition, the minimum number of GDCS equalizing trains required for a design basis LOCA remain OPERABLE. However, failure of a second equalizing train could result in less than the minimum required GDCS injection capacity assumed in the design basis LOCA analysis in Reference 1.

In this Condition, the inoperable GDCS equalizing train must be restored to OPERABLE status within 14 days. This Completion Time is acceptable based on engineering judgment considering the low probability of a failure of an additional GDCS equalizing train concurrent with a design basis LOCA during this period.

E.1 and E.2

This Condition applies when two or more injection branch lines or two or more equalizing trains are inoperable for reasons other than Condition A or B. In this Condition, the plant may not have sufficient GDCS capability to respond to a design basis LOCA. This Conditions also applies when Required Actions and Completion Time of Conditions A, B, C, or D are not met. In this Condition, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

This SR requires verification every 12 hours that the water level in each of the GDCS pools is within the specified limit. The minimum specified level ensures there is a sufficient volume of water in the drywell to ensure the core remains covered following a severe LOCA and support decay heat removal without operator intervention for a minimum of 72 hours.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 12-hour Frequency is acceptable because GDCS pool low level alarms will provide prompt notification of an abnormal level in any of the GDCS pools.

SR 3.5.2.2

This SR requires verification every 31 days of the continuity of the DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6 for each squib-actuated GDCS valve.

The 31-day Frequency is acceptable because either of the two safety-related initiators in each valve is capable of actuating the associated GDCS valve. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each squib-actuated GDCS valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in either division does not disable the GDCS valve because the valve will still be opened by the initiator in the other division.

SR 3.5.2.3

This SR requires verification every 24 months that each required GDCS valve actuates on an actual or simulated automatic initiation signal. The GDCS is required to actuate automatically to perform its design function. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.5.2 and 3.3.8.1 overlap this SR to provide complete testing of the assumed safety function.

This SR is modified by a Note that excludes squib valve actuation as a requirement for this SR to be met. This is acceptable because the design of the squib-actuated valve was selected for this application because of its very high reliability. The OPERABILITY of squib-actuated valves is verified by continuity tests and the Inservice Test Program for squib-actuated valves.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24-month Frequency for performing this SR is based on the need to perform this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed once per the 24-month refueling interval.

SR 3.5.2.4 and SR 3.5.2.5

SR 3.5.2.4 requires verification every 24 months on a STAGGERED TEST BASIS that the flow path for each pair of GDCS injection branch lines, from the GDCS pool to the associated squib valve and the associated RPV injection nozzle, is not obstructed. SR 3.5.2.5 requires verification every 24 months on a STAGGERED TEST BASIS that the flow path for each GDCS equalizing line, from the suppression pool to the associated squib valve and the associated RPV injection nozzle, is not obstructed. Verification that the GDCS lines and RPV nozzles are not obstructed can be performed using the GDCS line test connections and any combination of flow tests, flushing, visual inspection, or boroscopic inspection.

These SRs are modified by a Note that excludes squib valve actuation as a requirement for the SR to be met. This is acceptable because test connections allow access to both sides of the squib-actuated valves, allowing verification that the flow path is free of obstructions without actuating the squib valve.

The Frequency for performing these SRs is based on engineering judgment. This Frequency is acceptable because cleanliness controls provide a high degree of assurance that foreign material that could obstruct the GDCS lines will not be introduced into the GDCS pools, the suppression pool, or reactor vessel.

REFERENCES

1. Chapter 6.
2. Chapter 15.
3. 10 CFR 50.46.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 GDCS - Shutdown

BASES

BACKGROUND	A description of the ADS is provided in the Bases for LCO 3.5.1, "Automatic Depressurization System (ADS) - Operating." A description of the GDCS is provided in the Bases for LCO 3.5.2, "Gravity-Driven Cooling System (GDCS) - Operating." In MODES 5 and 6, GDCS is used to provide additional water inventory inside the containment to respond to a loss of decay heat removal capability or a loss of reactor coolant inventory. Loss of decay heat removal capability could result from the unavailability of both Reactor Water Cleanup/Shutdown Cooling loops, loss of reactor component cooling water or plant service water systems, or loss of preferred power. Loss of reactor coolant inventory could result from pipe breaks in the RCS associated with maintenance or refueling, misalignment of systems connected to the RCS, or leakage during replacement of control rod drive assemblies. GDCS pools with a minimum combined volume within the limit specified and the suppression pool provide additional water inventory to support decay heat removal for an extended period and makeup to respond to a loss of reactor coolant inventory. ADS supports the GDCS function by providing a vent path that is adequate to maintain the RPV close to containment pressure following loss of decay heat removal capability. The number of ADS valves required to support GDCS is a function of core decay heat load.
APPLICABLE SAFETY ANALYSES	Three GDCS pools and the suppression pool provide sufficient inventory when in MODES 5 and 6 to respond to a loss of non-safety-related decay heat removal capability for 72 hours without reliance on the Isolation Condenser System (Ref. 2). Three GDCS pools and the suppression pool also provide additional water inventory inside the containment on a loss of reactor coolant inventory (Ref. 1). Three injection subsystem branch lines (i.e. one from each GDCS pool) and one equalizing train are required to supply the required makeup. ADS capacity equivalent to six

BASES

APPLICABLE SAFETY ANALYSES (continued)	depressurization valves (DPVs), which is sufficient to maintain the RPV close to containment pressure following a LOCA or loss of decay heat removal capability is required to support GDCS injection. The GDCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires two injection subsystem branch lines associated with each of the three GDCS pools (i.e., six injection subsystem branch lines) and two equalizing subsystem trains. Additionally, to support OPERABILITY of the required GDCS subsystems, OPERABILITY of ADS valves (i.e., DPVs or SRVs or a combination of each) with relief capacity equivalent to six DPVs is required. These requirements ensure that the water inventory in three GDCS pools and the suppression pool will be injected in the event of any single failure. OPERABILITY of each required squib-actuated GDCS valve and each required ADS valve requires OPERABILITY of two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems - Shutdown."
APPLICABILITY	Two injection subsystem branch lines associated with each of the three GDCS pools, two equalizing subsystem trains, and ADS valves with relief capacity equivalent to six DPVs are required to be OPERABLE in MODES 5 and 6 to assure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in response to a loss of decay heat removal capability, a LOCA, or an inadvertent draindown of the RPV. These requirements are not applicable when the buffer pool gate is removed and water level is above the specified level over the top of the reactor pressure vessel flange because of the additional inventory available when in this configuration.
ACTIONS	<u>A.1</u> This Condition applies when one required GDCS injection branch line, one required GDCS equalizing train, or one required ADS valve is inoperable. In this Condition, the remaining OPERABLE branch lines, equalizing trains, and ADS valves provide sufficient RPV flooding capability to recover

ACTIONS (continued)

from a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown. However, overall reliability is reduced.

Therefore, the inoperable branch line, equalizing train, and ADS valve must be restored to OPERABLE within 14 days. The Completion Time is based on engineering judgment considering the need for prompt action to establish an alternate method to supply RPV inventory makeup or the need for timely restoration of vent capacity sufficient to allow GDCS injection.

B.1

This Condition applies when two or more required injection subsystem branch lines are inoperable. In this Condition, water in one or more GDCS pools may not be available to respond to a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown.

Required Action B.1 requires establishing at least two methods of injecting a combined water volume greater than or equal to the required GDCS pool volumes (1636 m^3 (57,775 ft^3)). Alternate sources and methods for water injection are identified in the plant's Abnormal and Emergency Operating Procedures. The method used to provide water for core flooding is based on plant conditions. The 4-hour Completion Time is based on engineering judgment considering the need for prompt action to establish an alternate method to supply RPV inventory makeup.

C.1

This Condition applies when two required equalizing subsystem trains are inoperable. In this Condition, water in the suppression pool may not be available to respond to a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown.

Required Action C.1 requires establishing at least two methods of injecting a combined water volume greater than or equal to the required suppression pool volume (799 m^3 (28,216 ft^3)). Alternate sources and methods for water injection are identified in the plant's Abnormal and Emergency Operating Procedures. The method used to provide water for core flooding is based on plant conditions. The

BASES

ACTIONS (continued)

4-hour Completion Time is based on engineering judgment considering the need for prompt action to establish an alternate method to supply RPV inventory makeup.

D.1.1, D.1.2, D.2

This Condition applies when GDCS is inoperable due to two or more required ADS valves being inoperable. In this Condition, RPV venting capacity may not be sufficient to allow GDCS injection. Required Action D.1.1 requires that GDCS injection capability be restored within 4 hours by establishing RCS vent path(s) with relief capacity equivalent to the required ADS valves. Manually actuated ADS valves may be used to satisfy this requirement. RCS vent paths other than ADS valves may be used provided the vent path(s) establish an RCS vent equivalent to 6 DPVs and are maintained open. A combination of OPERABLE ADS valves and other open vent paths can satisfy this Required Action.

Alternately, Required Action D.1.2 requires establishing at least two methods of injecting a combined water volume greater than or equal to the required GDCS and suppression pool volumes ($\geq 2435\ m^3$ ($85{,}991\ ft^3$)). Alternate sources and methods for water injection are identified in the plant's Abnormal and Emergency Operating Procedures. The method used to provide water for core flooding is based on plant conditions.

The Completion Times are based on engineering judgment considering the need for prompt action to establish an alternate method to supply RPV inventory makeup or the need for timely restoration of vent capacity sufficient to allow GDCS injection.

Required Action D.2 requires that LCO requirements be met within 72 hours. This Completion Time is based on engineering judgment considering the low probability of an event requiring GDCS injection when in this Condition.

E.1 and E.2

If the LCO is not met for reasons other than Condition A, B, or C, action must be initiated to provide at least two methods of injecting the minimum specified volume of water into the RPV. In addition, LCO requirements must be met within 72 hours. This Completion Time is based on engineering judgment considering the low probability of an event requiring GDCS injection when in this Condition.

BASES

ACTIONS (continued)

Alternate sources and methods for water injection are identified in the plant's Abnormal and Emergency Operating Procedures. The method used to provide water for core flooding is based on plant conditions.

F.1, F.2.1 and F.2.2

If Required Actions and associated Completion Times are not met, the water inventory available for injection may not be sufficient to respond to a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown. Therefore, actions to suspend operations with a potential for draining the reactor vessel (OPDRVs) must be initiated immediately to minimize the probability of a vessel draindown. Actions must continue until OPDRVs are suspended. In addition, action must be initiated immediately to establish reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) area isolation boundary. This can be accomplished by isolating the REPAVS and CONAVS dampers or verifying the automatic isolation capability of the respective exhaust high radiation function. This action is needed to establish appropriate compensatory measures for a potential loss of decay heat removal as a result of an inadvertent draindown event. The Completion Times are based on engineering judgment considering the need for prompt action to mitigate the consequences of a potential loss of decay heat removal capability, LOCA, or inadvertent vessel draindown.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

This SR requires verification every 24 hours that the water level in each of the GDCS pools is within the specified limit. This SR ensures adequate inventory is maintained in the containment to respond to a loss of decay heat removal capability or a loss of reactor coolant due to a LOCA or inadvertent draining of the RPV.

The 24-hour Frequency is acceptable because highly reliable GDCS pool low level alarms will provide prompt notification of an abnormal level in any of the GDCS pools.

SR 3.5.3.2

This SR requires verification every 24 hours that suppression pool level is sufficient to support the required operation of the GDCS equalizing trains in response to loss

BASES

SURVEILLANCE REQUIREMENTS (continued)

of decay heat removal capability, LOCA, or inadvertent vessel draindown. The 24-hour Frequency is acceptable because suppression pool low level alarms will provide prompt notification of an abnormal level in the suppression pool.

SR 3.5.3.3

This SR requires periodic verification that the supply pressure to required SRV accumulators is greater than or equal to the specified limit. An accumulator on each SRV provides pneumatic pressure for ADS valve actuation. The SRV accumulator capacity is sufficient for one actuation following a failure of the gas supply to the accumulator.

SR 3.5.3.3 is modified by two Notes. Note 1 states that this SR is only required to be met in MODE 5 and in MODE 6 prior to removal of the reactor pressure vessel head. ADS is not required for GDCS injection following removal of the reactor pressure vessel head. Note 2 states that the SRV accumulator supply pressure is only required to be met for SRVs that are credited with meeting the necessary relief capacity equivalent to 6 depressurization valves (DPVs).

The 31-day Frequency is acceptable because low pressure alarms provide prompt notification of an abnormal pressure in the accumulator supply.

SR 3.5.3.4

This SR requires verification every 31 days of the continuity of two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems - Shutdown," for each required GDCS valve, and for ADS valves required to support relief capacity equivalent to 6 DPVs. The 31-day Frequency is acceptable because either of the two safety-related initiators in each valve is capable of actuating the associated GDCS or ADS valve. Additionally, an alarm will provide prompt notification of loss of circuit continuity.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in

BASES

SURVEILLANCE REQUIREMENTS (continued)

either division does not disable the GDCS because the valve will still be opened by the squib initiator in the other division.

SR 3.5.3.5

This SR requires verification every 24 months that that each required GDCS valve and ADS valve required to support relief capacity equivalent to 6 DPVs actuates on an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.5.2 overlaps this SR to provide complete testing of the assumed safety function.

This SR is modified by two Notes. Note 1 states that for ADS valves this SR is only required to be met in MODE 5 and in MODE 6 prior to removal of the reactor pressure vessel head. ADS is not required for GDCS injection following removal of the reactor pressure vessel head. Note 2 excludes valve actuation as a requirement for this SR to be met. OPERABILITY of required squib-actuated valves is verified by continuity tests and the Inservice Test Program for squib-actuated valves. Required SRVs are tested in accordance with the Inservice Test Program.

The 24-month Frequency for performing this SR is based on the need to perform this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed once per the 24-month refueling interval.

SR 3.5.3.6

SR 3.5.3.6 requires the performance of SRs 3.5.2.4 and 3.5.2.5 from LCO 3.5.2. Refer to the corresponding Bases for LCO 3.5.2 for a discussion of each SR.

REFERENCES

1. Chapter 6.

2. Chapter 15.

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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Isolation Condenser System (ICS) - Operating

BASES

BACKGROUND

The Isolation Condenser System (ICS) actuates automatically following a reactor pressure vessel (RPV) isolation and transfers sufficient heat from the RPV to the Isolation Condenser/Passive Containment Cooling System IC/PCCS pool to prevent safety relief valve (SRV) actuation (Ref. 1). LCO 3.7.1, "Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools," supports the ICS in removing sufficient decay heat following an RPV isolation to cool the reactor to safe shutdown conditions (MODE 4) within 36 hours and maintain the reactor in a safe condition for an additional 36 hours with minimal loss of RCS inventory (Ref. 1). The ICS also provides water inventory to the RPV at the start of a LOCA and provides the initial RPV depressurization following a loss of feedwater allowing ADS initiation to be delayed. The ICS is also assumed available to respond to a Station Blackout and an Anticipated Transient without Scram (Ref. 1).

The ICS consists of four independent trains. Each ICS train includes a heat exchanger (isolation condenser), a steam supply line that connects the top of the isolation condenser to the RPV, a condensate return line that connects the bottom of the isolation condenser to the RPV, a high point purge line, and vent lines from both the upper and lower headers of the isolation condenser. The isolation condensers are located above the containment and are submerged in a large pool of water (IC/PCCS pool) that is at atmospheric pressure. Steam produced in IC/PCCS pools by boiling around the isolation condenser is vented to the atmosphere (Ref. 1).

Each of the four isolation condensers consists of two identical modules. Each module includes an upper and lower header connected by a bank of vertical tubes. A single vertical steam supply line directs steam from the RPV to the horizontal upper header in each module through four branch lines. The branch lines include flow restrictors that limit the consequences of a line break. Steam is condensed inside banks of vertical tubes that connect the upper and lower headers in each module and the condensate collects in the lower header. Each ICS condensate return line includes an in-line vessel that provides additional water inventory to the RPV when the ICS is initiated.

BASES

BACKGROUND (continued)

Operation of each ICS train is initiated by opening either the condensate return valve or the condensate return bypass valve. These valves are in parallel and are both normally closed.

The condensate return valves open on an ICS initiation signal. The condensate return bypass valves open on loss of power.

With both the condensate return valve and condensate return bypass valves closed and the steam supply line to the reactor open, the isolation condenser and the condensate return line fill with condensate to a level above the upper headers. The steam supply line, which is insulated to prevent the accumulation of condensate, remains filled with steam. A purge line with an orifice connects the top of the isolation condenser to a main steam line. Flow through the purge line when the ICS is in standby prevents the accumulation of non-condensable gases in the top of the isolation condenser.

Upon receipt of an ICS initiation signal, the condensate return valves open causing the condensate in the isolation condenser and condensate return line to return to the RPV. Steam from the RPV continues to condense in the isolation condenser and drains back to the RPV.

Beginning six hours after ICS initiation, radiolytically generated non-condensable gases are automatically, continuously vented to the suppression pool through vent lines connected to the lower header of the isolation condenser. The lower header vent valves also open automatically on high reactor pressure, which could be indicative of a loss of flow through the ICS. Operation of the lower header vent in each train is initiated by opening two, parallel connected, lower header vent valves or, opening two, series connected, lower header vent bypass valves. The lower header vent valves are normally closed, fail-open solenoid-operated valves. One of the valves is controlled by the Safety System Logic and Control /Engineered Safety Features (SSLC/ESF) System described in the Bases for LCO 3.3.5.3, "Isolation Condenser System (ICS) Instrumentation," and LCO 3.3.5.4, "Isolation Condenser System (ICS) Actuation." The other lower header vent valve is controlled by the Diverse Protection System (DPS), which is designed to mitigate digital protection system common mode failures. The lower header vent bypass valves are a relief valve and normally closed, fail-open solenoid valve. The lower header vent bypass valves open automatically (with

BASES

BACKGROUND (continued)

or without power) at a pressure higher than the lower header vent valves and at a pressure lower than what is needed to lift the SRVs.

Each ICS condenser is located in a sub-compartment of the IC/PCCS pool. Following RPV isolation, pool water temperature could rise to about 101°C (214°F). The steam formed will be non-radioactive and have a slight positive pressure relative to station ambient. The steam generated in the IC/PCCS pool is released to the atmosphere through large-diameter discharge vents. Each ICS train is designed to remove 33.75 MWt of decay heat when the reactor is above normal operating pressure so that any three of the four ICS trains have sufficient capacity to perform the ICS design function (Ref. 1).

Each of the condensate return valves is equipped with four solenoids (i.e., initiators). A signal to any of the four initiators will actuate the valve. Three of the four initiators on each valve are actuated by the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System described in the Bases for LCO 3.3.5.3, "Isolation Condenser System (ICS) Instrumentation," and LCO 3.3.5.4, "Isolation Condenser System (ICS) Actuation." The fourth initiator is actuated by the Diverse Protection System (DPS), which is designed to mitigate digital protection system common mode failures. The operator is able to stop any individual ICS train whenever the RPV pressure is below a reset value, overriding ICS automatic actuation signals.

Power to each of the three safety-related initiators on each ICS valve is supplied from a different division of the DC and Uninterruptible AC Electrical Power Distribution. As such, at least two of the three initiators in each ICS condensate return valve will be associated with divisions required by LCO 3.8.6, "Distribution Systems - Operating."

Each ICS condenser forms a closed safety-related loop outside the containment that acts as a "passive" substitute for an open "active" valve outside the containment. In addition, the ICS steam supply line and condensate return line each include two, normally open containment isolation valves in series. These valves close automatically to isolate the RPV on indication of a leak or break in the ICS that could bypass the containment. Specifically, high flow indicated on two of the four differential pressure transmitters on each steam supply line or high flow indicated on two of the four differential pressure

BASES

BACKGROUND (continued)	transmitters on each condensate return line will close all four isolation valves on the associated ICS train. Additionally, elevated radiation levels on two of the four radiation monitors associated with the steam space above each ICS pool subcompartment cause an alarm on radiation levels indicative of a minor leak and will isolate the steam supply and condensate return line of the associated ICS train on radiation levels indicative of a significant leak. Similarly, each ICS purge line also penetrates the containment to the closed system and is equipped with an excess flow check valve and a normally open shutoff valve. Each ICS venting line also penetrates the containment to the closed system. The upper header vent line is equipped with two normally closed, fail-closed solenoid valves in series; the lower header vent line is equipped with an excess flow check valve in series with a restricting orifice; and the lower header vent bypass line is equipped with a high-pressure relief valve in series with a normally closed, fail-open solenoid valve. The ICS isolation valves are also automatically signaled to close upon receipt of an open signal from two or more Depressurization Valves (DPVs). Closing the ICS isolation valves mitigates the accumulation of radiolytic hydrogen and oxygen, and there is sufficient time allotted for the water stored in the ICS condensate line to drain to the RPV prior to the isolation. The ICS is designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ICS subsystems when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE.
APPLICABLE SAFETY ANALYSES	The ICS is assumed to function following an RPV isolation or low water level (Level 2) event (Ref. 1). Operation of three of the four ICS trains after RPV isolation will limit RCS pressure enough to prevent safety relief valve (SRV) actuation. By conserving reactor water inventory following the RPV isolation, ICS minimizes the need for automatic reactor depressurization that would be required to add additional water inventory from low pressure sources.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The ICS also has an ECCS function to provide liquid inventory to the RPV during the initial stages of a LOCA. The ICS also provides the initial depressurization of the reactor during a loss of feed water so that ADS initiation can be delayed. ICS - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires four ICS trains to be OPERABLE. OPERABILITY of each condensate return valve and the SSCL/ESF-actuated lower header vent valve requires OPERABILITY of two safety-related initiators associated with electrical divisions required by LCO 3.8.6. The condensate return bypass valve, the DPS-actuated lower header vent valve, and the lower head vent bypass valves are not required for ICS OPERABILITY. The isolation valve for each ICS condenser subcompartment pool must be locked open. This ensures that the full capacity of the IC/PCCS pools is available to provide required cooling water to the ICS train for at least 72 hours after an RPV isolation or LOCA without the need for operator action. With the ICS subcompartment isolation valve locked open, subcompartment level is maintained in accordance with the requirements in LCO 3.7.1, "Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools."
APPLICABILITY	Four ICS trains are required to be OPERABLE in MODES 1 and 2 and in MODES 3 and 4 when < 2 hours since reactor was critical, to remove reactor decay heat, or provide additional RCS inventory following a LOCA, a loss of feedwater, or a reactor shutdown with isolation. In addition, in MODES 1 and 2, the ICS is required to be OPERABLE to prevent unnecessary automatic reactor depressurization or SRV actuation following RPV isolation or low water level events. ICS requirements in MODES 3 and 4 when ≥ 2 hours since reactor was critical, and in MODE 5 are specified in LCO 3.5.5, "Isolation Condenser System (ICS) - Shutdown."
ACTIONS	<u>A.1</u> This Condition applies when one of the four ICS trains is inoperable. In this Condition, the remaining three trains have adequate capacity to respond to events described in

ACTIONS (continued)

References 1 and 2. However, the overall reliability is reduced because a failure in one of the OPERABLE trains could result in an insufficient ICS capacity. In this Condition, the inoperable ICS train must be restored to OPERABLE status within 14 days. This Completion Time is acceptable based on engineering judgment considering the low probability of a failure of an additional ICS train concurrent with a design basis event during this period.

B.1

This Condition applies when two or more ICS trains are inoperable. In this condition, the ICS may not have sufficient capacity to respond to events described in References 1 and 2. This Condition also applies when the Required Actions and associated Completion Time of Condition A or B are not met. In this Condition, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowable Completion Time is reasonable, based on plant design, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

This SR requires periodic verification that each ICS manual, power-operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position. This SR is intended to ensure proper valve alignment in any flow path required for proper operation of the ICS. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position upon locking, sealing, or securing.

This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of being mispositioned are in the correct position. The 31-day Frequency for performing this SR is acceptable based on engineering judgment and was chosen to provide added assurance that ICS valves are correctly positioned.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

This SR requires verification every 31 days that the High Pressure Nitrogen Supply System (HPNSS) pressure to each nitrogen-operated ICS steam supply and condensate return valve is within the specified limit. The 31-day Frequency is acceptable because HPNSS low pressure alarms will provide prompt notification of an abnormal pressure in the HPNSS.

SR 3.5.4.3

This SR requires verification every 31 days of the continuity of two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6 for each condensate return valve and each SSLC/ESF-actuated lower header vent valve. The 31-day Frequency is acceptable because either of the two safety-related initiators in each valve is capable of actuating the associated ICS valve. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each ICS valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in either division does not disable the ICS valve because the valve will still be opened by the initiator in the other division.

SR 3.5.4.4

This SR requires periodic verification that each ICS subcompartment manual isolation valve is locked open. This SR ensures that the level in the subcompartment is the same as the level in the associated expansion pool and that the full volume of water in the IC/PCCS pools is available to each condenser. If this SR is not met, the associated ICS train may not be capable of performing its design functions. The 24-month Frequency for this SR is based on engineering judgment and is acceptable because the manual isolation valves between the IC/PCCS pool and the ICS subcompartments are locked open and maintained in their correct position under administrative controls.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.5

This SR requires periodic verification that the ICS actuates on an actual or simulated automatic initiation signal. The ICS is required to actuate automatically to perform its design function. This Surveillance test verifies that the automatic initiation logic will cause the ICS to operate as designed when a system initiation signal (actual or simulated) is received. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.5.4 overlaps this Surveillance to provide complete testing of the assumed ICS function.

The 24-month Frequency for performing this SR is acceptable based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power.

SR 3.5.4.6

This SR requires periodic verification that the heat removal capability of each ICS train satisfies requirements specified in Reference 1. The temperature sensor located downstream of the condensate return isolation valve and the differential pressure transmitter on the condensate return line may be used to provide test data. The Frequency, prior to exceeding 25% RTP if not performed in the previous 24 months on a STAGGERED TEST BASIS, is based on engineering judgment and allows deferring performance until plant conditions needed to perform the test are established.

REFERENCES

1. Section 5.4.6.
2. Section 6.3.3.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Isolation Condenser System (ICS) - Shutdown

BASES

BACKGROUND

The ICS is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation to provide adequate RPV pressure reduction to preclude safety relief valve operation and provide core cooling while conserving reactor water inventory (Ref. 1). A description of the ICS is provided in the Bases for LCO 3.5.4, "Isolation Condenser System (ICS) - Operating." When the reactor is shutdown, a reduced ICS capability is maintained to provide cooldown capability and to ensure a highly reliable and passive alternative to the Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) system for decay heat removal.

RWCU/SDC consists of two independent and redundant trains powered from separate electrical divisions that can be powered from either offsite power or the standby diesel generators. However, RWCU/SDC is a nonsafety-related system that cannot be assumed to remain available following an equipment failure or a loss of offsite power. Depending on plant and equipment status, various alternatives to the RWCU/SDC for decay heat removal can be configured in MODES 3, 4 and 5. When the Isolation Condenser/Passive Containment Cooling System (IC/PCCS) pool and the individual ICS pool subcompartments are flooded, use of one or more ICS loops is the preferred backup method for decay heat removal in MODES 3 and 4.

Although not effective for decay heat removal in MODE 5, the ICS does provide a highly reliable and passive backup to the RWCU/SDC for decay heat removal in this MODE. If normal decay heat removal capability is lost, the reactor coolant temperature will increase until the ICS provides the required decay heat removal capacity.

APPLICABLE SAFETY ANALYSES

A highly reliable, safety-related, and passive alternative to RWCU/SDC for decay heat removal when shutdown is not required for mitigation of any event or accident evaluated in the safety analyses. However, decay heat removal must be accomplished to prevent core damage.

ICS - Shutdown satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO requires that two trains of ICS be OPERABLE when shutdown to provide a backup method for decay heat removal. OPERABILITY of each condensate return valve and the Safety System Logic and Control/Engineered Safety Feature (SSLC/ESF)-actuated lower header vent valve requires OPERABILITY of two safety-related initiators associated with electrical divisions required by LCO 3.8.6. The condensate return bypass valve, the Diverse Protection System (DPS)-actuated lower header vent valve, and the lower head vent bypass valves are not required for ICS OPERABILITY.

With the RPV water level above the ICS steam supply line, OPERABILITY of the ICS function is not impacted (Ref. 2).

When in MODE 5, required ICS loops require functionality of associated IC/PCCS expansion pools as heat sink for the ICS condensers.

APPLICABILITY

This LCO requires that two trains of ICS be OPERABLE in MODES 3 and 4 when it has been ≥ 2 hours since the reactor was critical, and in MODE 5.

ACTIONS

A.1, A.2. A.3, and A.4

If one or more of the required ICS trains are not available, the plant may not have a reliable and passive alternative to RWCU/SDC for decay heat removal. Therefore, action must be taken immediately to restore the required ICS train(s) to operable status.

With one of the two required ICS trains inoperable, the remaining train is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both ICS trains inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial ICS train inoperability. The 1-hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued decay heat removal capability.

BASES

ACTIONS (continued)

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability.

Alternate methods that can be used include (but are not limited to) the RWCU/SDC System and the Fuel and Auxiliary Pools Cooling System. With one or more required ICS train(s) inoperable, at least one method of decay heat removal is verified to be in operation. The 1-hour Completion Time is based on engineering judgment recognizing the need to provide decay heat removal. Furthermore, verification must be reconfirmed every 12 hours thereafter. This will provide assurance of continued decay heat removal capability.

During the period when the required ICS train(s) is inoperable, the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

B.1 and B.2

This Condition applies when the Required Actions and associated Completion Times are not met. In this Condition, action must be initiated immediately to establish reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) area isolation boundary. This can be accomplished by isolating the REPAVS and CONAVS dampers or verifying the automatic capability of the respective exhaust high radiation function. This action is needed to establish appropriate compensatory measures for a loss of decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

This SR requires verification every 31 days that each ICS manual, power-operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position. This SR is intended to ensure proper valve alignment in any flow path required for proper operation of the ICS. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position upon locking, sealing, or securing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of being mispositioned are in the correct position.

The 31-day Frequency for performing this SR is acceptable based on engineering judgment and was chosen to provide added assurance that ICS valves are correctly positioned.

SR 3.5.5.2

This SR requires verification every 31 days that the High Pressure Nitrogen Supply System (HPNSS) pressure to each nitrogen-operated ICS valve is within the specified limit. The 31-day Frequency is acceptable because highly reliable HPNSS low pressure alarms will provide prompt notification of an abnormal pressure in the HPNSS.

SR 3.5.5.3

This SR requires verification every 31 days of the continuity of two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each condensate return valve and each SSLC/ESF-actuated lower header vent valve.

The 31-day Frequency is acceptable because either of the two safety-related initiators in each valve is capable of actuating the associated ICS valve. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each ICS valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently. The operation of the disable/test switch in either division does not disable the ICS valve because the valve will still be opened by the initiator in the other division.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.5.4

This SR requires verification every 24 months that each ICS subcompartment manual isolation valve is locked open. This SR is necessary to ensure that the full volume of water in the IC/PCCS pools is available to each condenser. If this SR is not met, the associated ICS loop may not be capable of performing its design functions. The 24-month Frequency for this SR is based on engineering judgment and is acceptable because the manual isolation valves between the IC/PCCS pool and the ICS subcompartments are locked open and maintained in their correct position under administrative controls.

SR 3.5.5.5

This SR requires verification every 24 months that the ICS actuates on an actual or simulated automatic initiation signal. The ICS is required to actuate automatically to perform its design function. This Surveillance test verifies that the automatic initiation logic will cause the ICS to operate as designed when a system initiation signal (actual or simulated) is received. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.4 overlaps this Surveillance to provide complete testing of the assumed ICS function.

The 24-month Frequency for performing this SR is acceptable based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the SR were performed with the reactor at power.

SR 3.5.5.6

SR 3.5.5.6 requires the performance of SR 3.5.4.6 from LCO 3.5.4. Refer to the corresponding Bases for LCO 3.5.4 for a discussion of this SR.

REFERENCES

1. Section 5.4.6.

2. NEDO-33201, ESBWR Certification Probabilistic Risk Assessment, Section 16.4.1, Revision 6, October 2010.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Containment

BASES

BACKGROUND

The function of the containment is to isolate and contain fission products released from the reactor coolant system following a design basis loss of coolant accident (LOCA) and to confine the postulated release of radioactive material to within limits. The containment structure is a reinforced concrete cylindrical structure, which encloses the reactor pressure vessel and its related systems and components. The containment structure has an internal steel liner, which provides an essentially leak-tight barrier against an uncontrolled release of radioactive material to the environment.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE automatic containment isolation system or

   2. Closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Containment Isolation Valves (CIVs),"

b. Containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Containment Air Lock,"

c. All equipment hatches are closed, and

d. The sealing mechanism (e.g., welds, bellows, or O-rings) associated with a penetration is OPERABLE.

This Specification ensures that the performance of the containment, in the event of a design basis accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

BASES

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate such that the postulated release of fission-product radioactivity subsequent to a DBA will not result in doses in excess of the values given in the licensing basis.

The DBA that results in a release of radioactive material within containment is a LOCA. In the analysis of this accident, it is assumed that containment is OPERABLE at event initiation such that release of fission products to the environment is controlled by the rate of containment leakage.

Analytical methods and assumptions involving the containment are presented in References 1 and 2. The safety analyses assume a non-mechanistic fission-product release following a DBA that forms the basis for determination of offsite doses. The fission-product release is in turn based on an assumed leakage rate from the containment. OPERABILITY of the containment ensures that the leakage rate assumed in the safety analyses is not exceeded, and that the site boundary radiation dose will not exceed the limits of 10 CFR 52.47(a)(2)(iv) and Regulatory Guide 1.183 (Refs. 4 and 5, respectively) even if the non-mechanistic release were to occur.

The maximum allowable leakage rate for the containment (L_a) is 0.35% by weight of the containment air per 24 hours at the maximum calculated containment pressure (Ref. 1), excluding MSIV leakage. The bulk of the containment leakage is released into the reactor building. The remaining portion of primary leakage is assumed to leak through the Passive Containment Cooling System (PCCS) into the airspace directly above the Isolation Condenser/PCCS (IC/PCCS) pools and is quickly vented directly to the atmosphere.

Containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met. Additionally, the drywell-to-wetwell gas space leakage must be within acceptance criteria to ensure the pressure suppression function.

BASES

LCO (continued)

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the containment air locks are addressed in LCO 3.6.1.2.

APPLICABILITY

The containment is required to be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODES 5 and 6 to prevent leakage of radioactive material from containment.

ACTIONS

A.1

If the containment is inoperable, a DBA could cause a release of radioactive material to containment. Therefore, the containment must be restored to OPERABLE status within 1 hour.

The 1-hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABILITY during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods where containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status in the required Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage testing (SR 3.6.1.2.1) or main steam isolation valve leakage (SR 3.6.1.3.9) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Containment Leakage Rate Testing Program. As-left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for Option B for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

This SR measures inleakage past the feedwater flow isolation valves into the containment to ensure that leakage past the feedwater isolation valves is within allowable limits (Ref. 6).

Limiting the leakage from the feedwater system outside containment into the containment is necessary to limit mass water additions to the containment during and following a design basis feedwater line rupture inside containment.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

SR 3.6.1.1.3

Maintaining the pressure suppression function of the containment requires limiting the leakage from the drywell to the wetwell. Thus, if an event were to occur that pressurizes the drywell, the steam would be directed through the horizontal vent pipes into the wetwell. This SR measures the wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve pathway leakage to ensure that these leakage paths are within allowable limits.

SURVEILLANCE REQUIREMENTS (continued)

Satisfactory performance of this SR can be achieved by establishing a known initial differential pressure (≥ 2.0 psid [14 kPaD]) between the drywell side and the wetwell side of the vacuum breaker and isolation valve and verifying that the measured leakage for each is ≤ 15% of the equivalent leakage through an acceptable design basis value $A/\sqrt{K}$ of 2.0 cm^2 (2.16E-03 ft^2). The leakage test is performed every 24 months. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

The SR is modified by a Note stating that performance of SR 3.6.1.1.5 satisfies this Surveillance Requirement. This is acceptable since SR 3.6.1.5 ensures margin to the design basis pressure suppression function, including the wetwell-to-drywell vacuum breaker leakage. Excluding the isolation valve leakage measurement when performing SR 3.6.1.1.5 introduces minimal added uncertainty based on its role as a backup isolation device and its reliability.

SR 3.6.1.1.4

Maintaining the pressure suppression function of the containment requires limiting the leakage from the drywell to the wetwell. Thus, if an event were to occur that pressurizes the drywell, the steam would be directed through the horizontal vent pipes into the wetwell. This SR determines the total wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve pathway leakage (maximum pathway) to ensure that these leakage paths are within allowable limits.

For those outages where the overall drywell-to-wetwell gas space leakage test is not conducted, the vacuum breaker and vacuum breaker isolation valve leakage test verifies that even with the maximum allowable total leakage, a margin of 65% remains for potential passive structural leakage. Historical industry drywell-to-wetwell gas space test data indicates that the leakage through the passive structural components is a small fraction of the remaining 65% margin. The total vacuum breaker leakage limit, combined with negligible leakage from the passive structural area, ensures that the drywell-to-wetwell gas space leakage limit is met for those outages in which the overall drywell-to-wetwell gas space leakage test is not performed.

SURVEILLANCE REQUIREMENTS (continued)

Satisfactory performance of this SR is achieved by summing the individual wetwell-to-drywell vacuum breaker/vacuum breaker isolation valve pathway leakages (from SR 3.6.1.3) on a maximum pathway basis and verifying that the total measured drywell-to-wetwell gas space leakage is ≤ 35% of the equivalent leakage through an acceptable design basis value $A/\sqrt{K}$ of 2.0 cm^2 (2.16E-03 ft^2). This Surveillance is performed every 24 months. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

The SR is modified by a Note stating that performance of SR 3.6.1.1.5 satisfies this Surveillance Requirement. This is acceptable since SR 3.6.1.5 ensures margin to the design basis pressure suppression function, including the wetwell-to-drywell vacuum breaker leakage. Excluding the isolation valve leakage measurement when performing SR 3.6.1.1.5 introduces minimal added uncertainty based on its role as a backup isolation device and its reliability.

<u>SR 3.6.1.1.5</u>

Maintaining the pressure suppression function of the containment requires limiting the leakage from the drywell to the wetwell. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the horizontal vent pipes into the wetwell. This SR determines effective overall suppression pool bypass leakage area to ensure that the leakage paths that would bypass the wetwell pressure suppression function are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known initial differential pressure (≥ 2.0 psid [14 kPaD]) between the drywell and the wetwell and verifying that the suppression pool bypass leakage equivalent to an area ≤ 50% of the bounding design basis value $A/\sqrt{K}$ of 2.0 cm^2 (2.16E-03 ft^2).

The overall suppression pool bypass leakage test is performed every 24 months. The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

BASES

REFERENCES

1. Section 6.2.

2. Section 15.4.

3. 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

4. 10 CFR 52.47(a)(2)(iv).

5. Regulatory Guide 1.183, July 2000.

6. Table 5.4-1.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Containment Air Lock

BASES

BACKGROUND

Two double-door containment air locks, one in the upper drywell region and one in the lower drywell region, are built into the containment to provide personnel access to the drywell while maintaining containment isolation during the process of personnel entering and exiting the drywell. The air lock is designed to withstand the same loads, temperatures, and peak design internal and external pressures as the containment (Ref. 1). As part of the containment, the air locks limit the release of radioactive material to the environment during normal plant operation and through a range of incidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to verify its ability to withstand pressures in excess of the maximum expected pressure following a DBA in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double seals and local leakage rate testing capability to ensure pressure integrity. To obtain a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each air lock is nominally a right circular cylinder with doors at each end that are interlocked to prevent simultaneous opening. The air lock is provided with limit switches on both doors that provide control room indication of door position. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Under some conditions as allowed by this LCO, the containment may be accessed through the air lock when the interlock mechanism has failed by manually performing the interlock function.

The containment air lock forms part of the containment pressure boundary. As such, air lock integrity and air tightness are essential to limit offsite doses from a DBA. Not maintaining air lock integrity or air tightness may result in offsite doses in excess of those described in the plant safety analyses. All leakage rate surveillance

BASES

BACKGROUND (continued)	requirements conform to 10 CFR 50, Appendix J, Option B (Ref. 2), as modified by approved exemptions described in the Containment Leakage Rate Testing Program.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within containment is a LOCA. In the analysis of this accident, it is assumed that containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of containment leakage. The containment is designed with an allowable leakage rate of 0.35% by weight of the containment per 24 hours at the calculated maximum containment pressure (Ref. 3), excluding MSIV leakage. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. The containment air lock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	As part of the containment pressure boundary, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. Two containment air locks are required to be OPERABLE. For the air lock to be considered OPERABLE, both air lock doors must be OPERABLE, the air lock interlock mechanism must be OPERABLE, and the air lock must be in compliance with the Type B air lock leakage testing requirements as described in the Containment Leakage Rate Testing Program. The closure of either the inner or outer door in each air lock is sufficient to provide a leak tight barrier following postulated events. However, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment. The air lock interlock mechanism allows only one air lock door to be opened at a time. This provision ensures that a gross breach of containment does not exist when the containment is required to be OPERABLE.

BASES

APPLICABILITY	The containment air locks are required to be OPERABLE in MODES 1, 2, 3, and 4 when a DBA could cause a significant increase in containment pressure and the release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of a LOCA are reduced because RPV pressure and temperature are lower. Therefore, maintaining OPERABILITY of the containment air locks is not required.
ACTIONS	Three Notes modify ACTIONS. Note 1 specifies that entry into and exit from the containment is permissible to perform repairs on the affected air lock. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit. Note 2 clarifies that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for operation to continue. This note clarifies that a subsequent inoperable air lock is governed by the same Condition and associated Required Actions used for the other air lock. Note 3 provides the clarification that Conditions and Required Actions of LCO 3.6.1.1, "Containment," are applicable when air lock leakage results in exceeding the overall containment leakage rate acceptance criteria. <u>A.1, A.2, and A.3</u> If one air lock door is inoperable, Required Action A.1 specifies that the OPERABLE door must be verified closed and remain closed. This action must be completed within 1 hour. Maintaining the OPERABLE door closed assures that a leak tight containment barrier is maintained by an OPERABLE air lock door. The 1-hour Completion Time is consistent with the

BASES

ACTIONS (continued)

Required Actions of LCO 3.6.1.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

Required Action A.2 specifies the air lock must be isolated by locking closed the OPERABLE air lock door within 24 hours. The 24-hour Completion Time is considered reasonable for locking the OPERABLE air lock door because the OPERABLE door is being maintained closed.

Required Action A.3 requires periodic verification that the air lock with an inoperable door has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The verification interval of 31 days is based on engineering judgment and is considered adequate in view of the administrative controls that make a mispositioned locked door unlikely.

Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, because access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

Two Notes modify the Required Actions for Condition A. Note 1 ensures that Condition C is entered if both doors in the air lock are inoperable. With both doors in an air lock inoperable, the Action to lock an OPERABLE door closed is not applicable. Required Actions C.1 and C.2 are the appropriate remedial actions.

Note 2 provides an allowance that entry and exit using an inoperable air lock is permissible under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time and that the door does not remain open longer than is required.

B.1, B.2, and B.3

If an air lock door interlock mechanism is inoperable, the Required Actions and associated Completion Times for one inoperable air lock door described for Condition A are applicable.

ACTIONS (continued)

Two Notes modify the Required Actions. Note 1 ensures that Condition C is entered if both doors in the air lock are inoperable. With both doors in an air lock inoperable, the Action to lock an OPERABLE door closed is not applicable. Required Actions C.1 and C.2 are the appropriate remedial actions.

Note 2 provides an allowance that entry and exit using an inoperable air lock is permissible under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time and that the door does not remain open longer than is required.

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, because access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 specifies that action must be initiated to evaluate containment overall leakage rate using current air lock test results to verify that the requirements of LCO 3.6.1.1 are being met.

Required Action C.2 specifies that the OPERABLE door be verified closed and remain closed. This action must be completed within 1 hour. This specified time period is consistent with the Required Actions of LCO 3.6.1.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

Required Action C.3 specifies that the air lock must be restored to OPERABLE status within 24 hours. The 24-hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status, considering that at least one door in the air lock is maintained closed.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not

BASES

ACTIONS (continued)

apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is specified in the Containment Leakage Rate Testing Program.

Two Notes modify SR 3.6.1.2.1. Note 1 clarifies that an inoperable air lock door does not invalidate the previous successful performance of an overall air lock leakage test. This is acceptable because either air lock door is capable of providing a fission-product barrier in the event of a DBA.

Note 2 specifies that the results of containment air lock leakage rate testing be evaluated as part of the acceptance criteria applicable to SR 3.6.1.1.1.

SR 3.6.1.2.2

This SR requires periodic verification that the air lock door interlock will function as designed and that simultaneous inner and outer door opening will not occur inadvertently.

The 24-month Frequency is based on engineering judgment and is acceptable because the interlock mechanism is typically not challenged when containment is entered. Additionally, indications of air lock door status would alert operators promptly of a failure of an interlock.

BASES

REFERENCES

1. Section 3.8.

2. 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

3. Section 6.2.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Containment Isolation Valves (CIVs)

BASES

BACKGROUND

The function of CIVs is to limit fission-product release during and following postulated Design Basis Accidents (DBAs) to values less than 10 CFR 52.47(a)(2)(iv) (Ref. 1) offsite dose limits and GDC 19 control room dose limits (Ref. 2). The OPERABILITY requirements for CIVs help ensure that adequate containment leak tightness is maintained during and after an accident by minimizing potential leakage paths to the environment. Containment isolation, within the time limits specified for those isolation valves designed to close automatically, ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the DBA analyses. Therefore, the OPERABILITY requirements provide assurance that containment leakage rates assumed in the safety analyses will not be exceeded.

Containment isolation devices are either passive or active (automatic). Passive devices include manual valves, deactivated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems. Active devices include check valves and automatic valves designed to close following an accident without operator's action.

Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation (and possibly loss of containment integrity) or leakage that exceeds limits assumed in the safety analyses. The ESBWR design does not credit any closed system inside containment as a containment barrier.

Main Steam Isolation Valves (MSIVs) and main steamline (MSL) drain isolation valves are actuated by the Reactor Trip and Isolation Function (RTIF) portion of the Leak Detection and Isolation System (LD&IS) as described in Bases for LCO 3.3.6.1, "Main Steam Isolation Valve (MSIV) Instrumentation," and LCO 3.3.6.2, "Main Steam Isolation Valve (MSIV) Actuation." Each MSIV is equipped with two safety-related solenoids (i.e., the safety-related initiators). Both MSIV safety-related initiators must de-energize to close the MSIV.

BASES

BACKGROUND (continued)	Automatic containment isolation valves (other than MSIVs and MSL drain isolation valves) are actuated by the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) portion of LD&IS as described in Bases for LCO 3.3.6.3, "Isolation Instrumentation," and LCO 3.3.6.4, "Isolation Actuation." The automatic containment isolation function of the LD&IS is designed to ensure that no single active component failure will prevent automatic isolation of any containment penetration when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE. The diverse protection system (DPS) performs selected containment isolation functions as part of the diverse ESF function, which is designed to mitigate digital protection system common mode failures. As described in Bases for LCO 3.3.8.1, "Diverse Protection System," the Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System CIVs are required to have OPERABLE diverse isolation capability.
APPLICABLE SAFETY ANALYSES	This LCO was derived from the requirements related to the control of offsite radiation doses resulting from major accidents. As delineated in 10 CFR 52.47(a)(2)(iv) (Ref. 1), a proposed site must consider a fission-product release from the core, with offsite release based on the expected demonstrable leakage rate from the containment. As part of the containment boundary, CIV function is essential to containment integrity. Therefore, the safety analysis of any event requiring isolation of containment is applicable to this LCO. The DBAs that result in a release of radioactive material within containment are a LOCA such as a main feedwater line break, or a main steam line break (MSLB). In the analysis for each of these accidents, it is assumed that CIVs are either closed or close within the required isolation times following event initiation. This ensures that potential leakage paths to the environment through CIVs are minimized. The MSIVs are required to close in ≥ 3 but ≤ 5 seconds; therefore, the 5-second closure time is assumed in the analysis. Likewise, it is assumed that the containment is isolated such that release of fission products to the environment is controlled by the rate of containment leakage.

APPLICABLE SAFETY ANALYSES (continued)

The DBA analysis assumes isolation of the containment is complete and leakage is terminated, except for the maximum allowable leakage, (L_a). The containment isolation total response time includes signal delay and CIV stroke times. The single-failure criterion required to be imposed in the conduct of plant safety analyses was considered in the design of the containment isolation valves.

The CIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that each CIV is OPERABLE because CIVs form a part of the containment boundary. The CIV safety function is minimizing offsite radiation exposures resulting from a DBA. This LCO provides assurance that the CIVs will perform their designed safety functions to mitigate the consequences of accidents that could result in offsite exposure.

The automatic power-operated isolation valves are OPERABLE when their isolation times are within limits, the valves actuate on an automatic isolation signal, and excess flow check valves (EFCVs) actuate within the required differential pressure range.

For each automatically actuated CIV, the LCO requires OPERABILITY of required safety-related initiators (e.g., solenoids) associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating." For the RWCU/SDC System CIVs, the LCO also requires electrical continuity OPERABILITY of the DPS initiator (i.e., solenoid).

The normally closed isolation valves are OPERABLE when manual valves are closed, automatic valves are deactivated and secured in their closed position, and blind flanges are in place. The normally open manual isolation valves are OPERABLE when they are capable of closing.

The valves covered by this LCO are listed with their associated stroke times (if applicable) in Reference 5.

APPLICABILITY

CIVs must be OPERABLE in MODES 1, 2, 3, and 4 to protect against a DBA release of radioactive material to containment.

BASES

APPLICABILITY (continued)

In MODES 5 and 6, the probability and consequences of a LOCA are reduced because RPV pressure and temperature are lower. Therefore, OPERABILITY of CIVs is not required to ensure containment integrity when in MODE 5 or 6.

ACTIONS

The ACTIONS are modified by four Notes. Note 1 allows CIVs to be opened intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve to isolate the valve when a valid containment isolation signal is indicated.

Note 2 provides clarification that separate condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable CIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable CIVs are governed by subsequent Condition entry and application of associated Required Actions.

Note 3 requires that the OPERABILITY of the affected systems be evaluated when a CIV is inoperable. This ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable CIV. Note 4 specifies that the Conditions and Required Actions of LCO 3.6.1.1, "Containment," are applicable when CIV leakage results in exceeding overall containment leakage rate acceptance criteria when in MODES 1, 2, 3, and 4. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions are taken.

Periodic verification of isolation devices located in high radiation areas may be verified closed by use of administrative means. Allowing verification by administrative means is acceptable because access to these areas is typically restricted. Therefore, the potential for misalignment of these valves, once they have been verified to be in the proper position, is small.

Periodic verification of isolation devices that are locked, sealed, or otherwise secured in position may be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently

ACTIONS (continued)

repositioned. Therefore, the potential for misalignment of these devices, once they have been verified to be in the proper position, is low.

A.1

This Condition applies when one or more RWCU/SDC penetration flow path(s) have an inoperable DPS initiator (i.e., solenoid). In this Condition, required SSLC/ESF initiators will actuate the minimum number of CIVs assumed in the design basis analysis concurrent with any additional single failure.

In this Condition, the inoperable DPS initiator(s) must be restored to OPERABLE status within 30 days. This Completion Time is acceptable because the required safety-related initiators will actuate the minimum number of CIVs required to respond to the design basis LOCA concurrent with any additional single failure.

B.1 and B.2

If one of the CIVs in one or more penetration flow paths is inoperable for reasons other than Condition A or D, the penetration still has isolation capability but the ability to tolerate a single failure is lost. Therefore, Required Action B.1 requires that the affected penetrations must be isolated within 4 hours for penetrations other than the main steam line, and within 8 hours for main steam lines.

For penetrations isolated in accordance with Required Action B.1, the valve or device used to isolate the penetration should be the closest to the containment that is available. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve, a check valve with flow through the valve secured, or a blind flange.

The Completion Time of 4 hours to isolate penetrations (other than a main steam line) provides sufficient time to complete the action and is acceptable because the penetration still has isolation capability although the ability to tolerate a single failure is lost.

BASES

ACTIONS (continued)

The Completion Time of 8 hours to isolate a main steam line provides additional time to attempt restoration given that the isolation will result in a transient and the potential for a plant shutdown. This is acceptable because the penetration still has isolation capability although the ability to tolerate a single failure is lost. Continued operation with an isolated main steam line is only permitted if the plant safety analysis allows operation with an isolated main steam line. Such operation must be within the conditions, such as main steam line flow, assumed in the plant safety analysis. For example, justification for plant operation with an MSIV closed must evaluate the potential for significant degradation of components in the reactor and steam systems as a result of acoustic resonance in the active steam lines with increased flow rates. Otherwise, the plant must be placed in cold shutdown.

Required Action B.2 requires periodic verification that isolated penetrations remain isolated. This is necessary to ensure that containment penetrations required to be isolated following an accident, and which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected penetration is isolated is acceptable because the valves are operated under administrative control and the probability of their misalignment is low.

The Completion Time for verification of isolation valves inside containment is that verification must be completed prior to entering MODE 2 or 4 from MODE 5 if containment was de-inerted while in MODE 5 unless the verification was performed within the previous 92 days. This Completion Time is based on engineering judgment and is acceptable because of the inaccessibility of the valves and other administrative controls that ensure that valve misalignment is unlikely.

C.1

If two or more CIVs are inoperable in one or more penetration flow paths for reasons other than Condition A or D, isolation capability for the penetration may be lost.

BASES

ACTIONS (continued)

Therefore, at least one of the CIVs in each flow path must be restored to OPERABLE or Required Action C.1 requires that the penetration be isolated within one hour.

For penetrations isolated in accordance with Required Action C.1, the valve or device used to isolate the penetration should be the closest to the containment available. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve, a check valve with flow through the valve secured, or a blind flange.

The Completion Time of one hour is consistent with the ACTIONS of LCO 3.6.1.1, "Containment," and is reasonable considering the importance of maintaining containment integrity during MODES 1, 2, 3 and 4.

D.1

If MSIV or feedwater line leakage is not within required limits, the assumptions of the safety analysis for the radiological consequences of an event are not met. Therefore, the leakage must be restored to within the required limit.

Restoration of the leakage rate can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolation penetration is assumed to be the actual pathway leakage through the isolation device(s). If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices.

The Completion Time for restoration of MSIV or feedwater line leakage is 8 hours. The Completion Time is consistent with the Completion Time for isolation of an inoperable valve of the same type.

E.1 and E.2

If the Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be

BASES

ACTIONS (continued)

brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR requires periodic verification that each 25 mm (1 in), 350 mm (14 in), 400 mm (16 in), and 500 mm (20 in) containment purge valve is closed. This SR ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is inoperable.

This SR is modified by a Note that permits the 25 mm (1 in), 350 mm (14 in), 400 mm (16 in), and 500 mm (20 in) containment purge valves to be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

The 31-day Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. The 31-day Frequency is acceptable because containment purge valve status is available to operations personnel.

SR 3.6.1.3.2

This SR requires periodic verification that each manual CIV and blind flange that is located outside containment and is required to be closed during accident conditions is closed. This SR is not required on valves or blind flanges that are locked, sealed, or otherwise secured. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside the containment boundary is within design limits.

This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves or blind flanges located outside containment and capable of being mispositioned are in the correct position. In this application, the term "sealed" has no connotation of leak tightness. A sealed valve utilizes a device that provides evidence of unauthorized manipulation (e.g., cable secured by means of a lead seal).

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 31-day Frequency is relatively easy and was chosen to provide added assurance that the valves are in the correct positions. The 31-day Frequency has been shown to be acceptable through operating experience. A Note has been added to this SR to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open.

SR 3.6.1.3.3

This SR requires verification every 31 days of the continuity of the RWCU/SDC DPS initiator (i.e., solenoid) and of the required safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6 for each CIV.

The 31-day Frequency is acceptable because multiple initiators for each CIV are capable of actuating the associated CIV. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the initiators.

This SR is modified by a Note that continuity is not required to be met for one required initiator circuit intermittently disabled under administrative controls. This allows surveillance and maintenance with the assurance that the CIV will not be inadvertently isolated. The operation of the disable/test switch in one division does not disable the isolation function because of the capability of the remaining required initiator(s).

SR 3.6.1.3.4

This SR requires periodic verification that each manual CIV and blind flange that is located inside containment and required to be closed during accident conditions is closed. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside the containment boundary is within design limits.

For valves inside containment, the Frequency defined as "prior to entering MODE 2 or 4 from MODE 5 if containment was de-inerted while in MODE 5 and if not performed within the previous 92 days" is appropriate because these valves and flanges are operated under administrative control and the probability of their misalignment is low. A Note has been

BASES

SURVEILLANCE REQUIREMENTS (continued)

added to this SR to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open.

SR 3.6.1.3.5

This SR requires periodic verification that the isolation time of each power-operated and automatic CIV is within required limits. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. MSIVs are excluded from this SR because MSIV full-closure isolation time is demonstrated by SR 3.6.1.3.6.

The Frequency for this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.6

This SR requires periodic verification that the isolation time of each MSIV is within the required limits. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses.

The 24-month Frequency was developed to be consistent with the normal refueling interval and is acceptable based on engineering judgment.

SR 3.6.1.3.7

This SR requires periodic verification that each automatic CIV will actuate to its isolation position on a containment isolation signal. Containment isolation is required to prevent leakage of radioactive material from containment following a DBA. The LOGIC SYSTEM FUNCTIONAL TESTs in LCO 3.3.6.2, LCO 3.3.6.4, and LCO 3.3.8.1 overlap this SR to provide complete testing of the safety function.

This 24-month Frequency was developed to be consistent with the normal refueling interval. This Frequency will allow the SR to be performed during a plant outage because isolation of penetrations could disrupt cooling water flow and the normal operation of critical components.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.8

This SR requires periodic verification that for a representative sample of reactor instrumentation line EFCVs each reduces flow on a simulated line break. This SR provides assurance that the instrumentation line EFCVs will perform to increase margin to predicted radiological consequences during the postulated instrumentation line break event evaluated in Reference 3.

This 24-month Frequency was developed to be consistent with the normal refueling interval. This interval will allow the SR to be performed during a plant outage because of the potential for an unplanned plant transient if the SR is performed with the reactor at power.

SR 3.6.1.3.9

This SR requires periodic verification that the leakage rate through each main steam line is within the specified limit when tested at $\geq P_a$. The analyses in Reference 3 are based on the specified leakage limit.

The MSIV leakage rate must be verified at a frequency in accordance with Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analyses in Reference 3. Maintaining the MSIVs OPERABLE requires compliance with requirements of 10 CFR 50, Appendix J (Ref. 6), as modified by approved exemptions.

SR 3.6.1.3.10

This SR requires periodic verification that the combined feedwater isolation valves leakage rates for both feedwater line leakage paths is within limits. The leakage rates must be verified in accordance with Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analyses in References 3 and 4. Maintaining the combined feedwater line leakage paths OPERABLE requires compliance with requirements of 10 CFR 50, Appendix J (Ref. 6), as modified by approved exemptions, which are identified in the Containment Leakage Rate Testing Program.

BASES

REFERENCES

1. 10 CFR 52.47(a)(2)(iv).

2. 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC 19.

3. Section 15.4.

4. Section 6.2.

5. Section 6.2, Tables 6.2-15 through 6.2-45.

6. 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The upper limit for containment drywell pressure is an input to the analyses for containment performance during postulated loss-of-coolant accidents (LOCAs). The limit was selected based on plant operating experience as a reasonable upper bound during normal operation. This limitation on drywell pressure provides added assurance that the peak containment pressure does not exceed the design value of 310 kPaG (45.0 psig).
APPLICABLE SAFETY ANALYSES	Containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The upper limit for containment drywell pressure is an initial condition in the analyses (Ref. 1) that ensures that the peak drywell internal pressure will be maintained below the drywell design pressure in the event of a LOCA. The calculated peak drywell pressure for the limiting event is provided in Reference 1. Drywell pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that containment drywell pressure be maintained ≤ 106.9 kPa (15.5 psia) during normal operation. Maintaining containment drywell pressure within the specified limit ensures that an initial condition assumed in the safety analysis remains valid. This ensures that the peak LOCA drywell internal pressure will be maintained below the drywell design pressure in the event of a LOCA.
APPLICABILITY	Containment drywell pressure must be maintained within the specified limit in MODES 1, 2, 3, and 4 when a LOCA could cause a significant increase in containment pressure and the release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of LOCA are reduced because RPV pressure and temperature are lower.

BASES

APPLICABILITY (continued)	Therefore, maintaining drywell pressure within limits is not required when in MODE 5 or 6.

ACTIONS

A.1

If drywell pressure is not within the limits of the LCO, drywell pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the Required Actions of LCO 3.6.1.1, "Containment," which requires that Containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell pressure cannot be restored to within limits in the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

This SR requires periodic verification that drywell pressure is within the specified limit. This ensures that facility operation remains within the limits assumed in the containment analysis.

The 12-hour Frequency for this SR was developed based on operating experience related to trending of drywell pressure variations and pressure instrument drift during the applicable MODES. The 12-hour Frequency is acceptable because of other indications available in the control room, including drywell pressure alarms, will provide prompt notification of abnormal drywell pressure.

REFERENCES

1. Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND	During normal operation, the reactor vessel and piping add heat to the drywell airspace. Drywell coolers remove this energy and maintain appropriate drywell average air temperature. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limit on drywell average air temperature was developed as a reasonable upper bound based on the plant design and operating plant experience.
APPLICABLE SAFETY ANALYSES	Containment performance is evaluated for the spectrum of break sizes for postulated loss-of-coolant accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 1). Analyses assume an initial average drywell air temperature of 46.1°C (115°F). This assumption ensures that the safety analysis utilizes conservative initial conditions. Lower initial temperature represents more initial noncondensable gas mass, and consequently higher long-term analyzed containment pressure. Therefore, the Reference 1 analyses were performed well below the nominal drywell temperature during power operation to ensure conservative peak drywell pressure. Maintaining the operating initial conditions of ≤ 65.5°C (150°F) ensures that the peak post-LOCA drywell long-term temperature does not exceed the maximum allowable temperature of 171°C (340°F) and 121°C (250°F) for the drywell and wetwell, respectively (Ref. 2). The most severe drywell temperature condition occurs as a result of a feedwater line rupture. The maximum calculated drywell average temperature for the worst case break area is provided in Reference 1. Equipment inside containment required to mitigate the effects of a DBA is designed to operate and capable of operating under environmental conditions expected for the accident. Exceeding drywell average air temperature may result in the degradation of the equipment and containment structure under accident loads.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that drywell average air temperature be ≤ 65.5°C (150°F). In the event of a DBA, with an initial drywell average temperature less than or equal to the LCO temperature limit, the accident temperature profile assures that the drywell structural temperature is maintained below its design temperature and that required safety related equipment will continue to perform its function.
APPLICABILITY	Drywell average air temperature is required to be within specified limits in MODES 1, 2, 3, and 4. A DBA could cause a release of radioactive material to containment and cause a heatup and pressurization of containment. In MODES 5 and 6, the probability and consequences of a LOCA are reduced because RPV pressure and temperature are lower. Therefore, drywell average temperature within limits is not required in MODE 5 or 6.
ACTIONS	<u>A.1</u> If drywell average air temperature is not within the limit of the LCO, operation may not be within the assumptions of the containment analysis. Therefore, drywell average air temperature must be restored within the specified limit within eight hours. The 8 hour Completion Time provides sufficient time to correct minor problems or to prepare the plant for an orderly shutdown and is acceptable because of the low sensitivity of the analysis to variations in this parameter. <u>B.1 and B.2</u> If the drywell average air temperature cannot be restored within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The

BASES

ACTIONS (continued)

allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

This SR requires verification that drywell average air temperature is within specified limits every 24 hours. Permanently installed temperature sensors are provided in various locations and elevations inside containment. These sensors are fed to the plant computer for averaging and continuous monitoring of the containment.

The 24 hour Frequency of the SR is acceptable based on (1) operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and (2) the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is acceptable because highly reliable drywell average air temperature alarms will provide prompt notification of abnormal average air temperature.

REFERENCES

1. Section 6.2.
2. Table 6.2-1.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Wetwell-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the wetwell-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are three vacuum breaker flow paths between the drywell and the wetwell, which allow gas flow from the wetwell to the drywell when the drywell is at a negative pressure with respect to the wetwell. Therefore, wetwell-to-drywell vacuum breaker flow paths prevent an excessive negative differential pressure across the wetwell-drywell boundary. Each vacuum breaker is a process-actuated valve, similar to a check valve.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, the increased pressure inside the drywell forces a mixture of noncondensable gases, steam and water through the vertical/horizontal vent pipes into the suppression pool where the steam is rapidly condensed. Condensation of the steam remaining in the drywell is caused by the ECCS flooding of the RPV and cold water spilling out of the broken pipe directly into the drywell causes depressurization of the drywell.

On the upstream side of the vacuum breaker, a pneumatically operated fail as-is safety-related isolation valve is provided. During a LOCA, when the vacuum breaker opens to equalize the wetwell-to-drywell pressure and subsequently does not completely close as detected by the logic associated with proximity sensors and differential temperature from four groups of divisional thermocouples, a control signal will close the upstream isolation valve to prevent excessive bypass leakage due to the opening created by the vacuum breaker.

BASES

APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the wetwell-to-drywell vacuum breaker flow paths are presented in Reference 1 as part of the accident response of the containment systems. The vacuum breaker flow paths are provided as part of the containment to limit the negative pressure differential across the drywell and wetwell walls that form part of the containment boundary. A loss of coolant accident (LOCA) could result in excessive negative differential pressure across the wetwell-to-drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture. Subsequent condensation of the steam would result in depressurization of the drywell. The Reference 1 safety analyses assume that the vacuum breakers are closed initially and are open at a differential pressure of 3.07 kPa (0.445 psi). The analyses support that one vacuum breaker is sufficient to perform the relief function. The Reference 1 safety analyses also assume that all three vacuum breaker flow paths are isolated when the wetwell and drywell differential pressure is equalized, following the initial vacuum breaker opening. Because failure of a vacuum breaker flow path to isolate could result in excessive bypass leakage that would degrade the pressure suppression capability of the containment, each vacuum breaker flow path is equipped with an isolation valve that will close on a control signal if the associated vacuum breaker does not completely close, as detected by the logic associated with the proximity sensors and differential temperature from four groups of divisional thermocouples. The analyses show that the drywell-to-wetwell design pressure is not exceeded even under the worst-case accident scenario. The wetwell-to-drywell vacuum breakers and isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Only two of the three vacuum breaker flow paths must be OPERABLE for opening, with the associated vacuum breaker isolation valves in the open position. All wetwell-to-drywell vacuum breakers, however, are required to be closed (except during testing or when the vacuum breakers are performing their intended design function). Additionally, all vacuum breaker isolation valves must be OPERABLE for automatic closure.

BASES

LCO (continued)

Vacuum breaker flow path OPERABILITY provides assurance that the drywell-to-wetwell negative pressure differential remains below the design value. Vacuum breaker flow path OPERABILITY also ensures that there is no excessive bypass leakage should a LOCA occur to maintain the pressure suppression capability of the containment.

APPLICABILITY

Vacuum breaker flow path OPERABILITY must be maintained in MODES 1, 2, 3, and 4 when containment OPERABILITY is required to mitigate the effects of a LOCA.

In MODES 5 and 6, the probability and consequences of a LOCA are reduced because RPV pressure and temperature are lower. Therefore, maintaining wetwell-to-drywell vacuum breaker flow paths OPERABLE is not required in MODE 5 or 6 to ensure containment integrity.

ACTIONS

A.1

If one required wetwell-to-drywell vacuum breaker flow path is inoperable because its vacuum breaker will not open or the associated isolation valve is not open, the remaining OPERABLE vacuum breaker flow path is capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in the remaining vacuum breaker flow path could result in an excessive wetwell-to-drywell differential pressure during a LOCA. Therefore, 7 days is allowed to restore the inoperable wetwell-to-drywell vacuum breaker flow path to OPERABLE for opening status so that plant conditions are consistent with those assumed for the design basis analysis.

The Completion Time of 7 days is acceptable because the remaining OPERABLE required wetwell-to-drywell vacuum breaker flow path is capable of providing the vacuum relief function and the low likelihood of a LOCA with a single failure of a vacuum breaker during this period.

B.1

If one wetwell-to-drywell vacuum breaker flow path is inoperable because the vacuum breaker will not close or the associated flow path isolation function is inoperable, there is the potential for containment overpressurization due to this bypass leakage if a LOCA were to occur. An open vacuum breaker flow path allows communication between the drywell

BASES

ACTIONS (continued)

and wetwell airspace, degrading the pressure suppression capabilities of the containment. Therefore, the affected wetwell-to-drywell vacuum breaker flow path must be isolated within 8 hours.

C.1

If one wetwell-to-drywell vacuum breaker flow path is inoperable because the vacuum breaker will not close and the associated flow path isolation function is inoperable, there is a high potential for wetwell overpressurization due to bypass leakage if a LOCA were to occur. An open vacuum breaker flow path allows communication between the drywell and wetwell airspace, degrading the pressure suppression capabilities of the containment. Therefore, the affected wetwell-to-drywell vacuum breaker flow path must be isolated within 1 hour.

D.1

If two required wetwell-to-drywell vacuum breaker flow paths are inoperable (i.e., any combination of two of the two required flow paths for opening and the three flow paths for the isolation function), there is a high potential that an excessive wetwell-to-drywell differential pressure could exist during a LOCA, or for degradation of the pressure suppression capabilities of the containment. Therefore, one required wetwell-to drywell vacuum breaker flow path must be restored to OPERABLE status within 1 hour.

E.1 and E.2

If the Required Action and associated Completion Time cannot be met the plant must be brought to a MODE in which the LCO does not apply. To achieve this status the plant must be brought to at least MODE 3 within 12 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on plant design, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

This SR requires periodic verification that each vacuum breaker is closed to ensure that this potential large bypass leakage path is not present. This SR is performed by observing the vacuum breaker position indication.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 14 day Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. The 14 day Frequency is acceptable because vacuum breaker status is available to operations personnel and a highly reliable alarm will alert operations personnel of abnormal vacuum breaker position or valve alignment.

SR 3.6.1.6.2

This SR requires periodic verification that the vacuum breaker isolation valve associated with the two required vacuum breaker flow paths are open.

The 31 day Frequency is based on engineering judgment and has been shown to be acceptable through operating experience.

SR 3.6.1.6.3

This SR requires periodic verification of the free movement of the two required vacuum breakers by verifying that the force required to open each vacuum breaker is within limits to ensure they are capable of performing their intended function.

The 24 month Frequency was developed to coincide with the 24 month refueling interval because access to the vacuum breakers is required to perform the SR. The 24 month Frequency is acceptable based on the simplicity and reliability of the valve design. Specifically, the design of the ESBWR vacuum breaker has been enhanced by eliminating the actuator and the associated failure mode, improving the valve hinge design, and selecting materials which are resistant to wear and galling.

SR 3.6.1.6.4

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the required nominal trip setpoint within the "as-left tolerance" to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the Setpoint Control Program. The 24 month Frequency was developed to coincide with the 24 month refueling interval because access to the vacuum breakers is required to perform the SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.5

A system functional test is performed to ensure that each vacuum breaker flow path isolation function operates as required. This includes verifying that the isolation valve automatically closes when the associated vacuum breaker does not completely close, as detected by the logic associated with proximity switches and differential temperature from four groups of divisional thermocouples. The 24 month Frequency was developed to coincide with the 24 month refueling interval based on the need to perform this Surveillance under the conditions that apply during a plant outage.

REFERENCES

1. Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Passive Containment Cooling System (PCCS)

BASES

BACKGROUND

The Passive Containment Cooling System (PCCS) is designed to transfer heat from the containment drywell to the Isolation Condenser/PCCS (IC/PCCS) pools following a loss of coolant accident (LOCA). The PCCS consists of six independent condensers. Each condenser is a heat exchanger that is an integral part of the containment pressure boundary. The condensers are located above the containment and are submerged in a large pool of water (IC/PCCS pool) that is at atmospheric pressure. Steam produced in IC/PCCS pools by boiling around the PCCS condensers is vented to the atmosphere. LCO 3.7.1, "Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools," supports the PCCS in removing sufficient post-LOCA decay heat from the containment to maintain containment pressure and temperature within design limits for a minimum of 72 hours, without operator action (Ref. 1)

Each of the six PCCS condensers consists of two identical modules. A single central steam supply pipe, open to the drywell at its lower end, directs steam from the drywell to the horizontal upper header in each module. Steam is condensed inside banks of vertical tubes that connect the upper and lower header in each module. The condensate collects in each module's lower header and drain volume and then returns by gravity flow to the Gravity-Driven Cooling System (GDCS) pools. By returning the condensate to the GDCS pools, it is available to return to the reactor pressure vessel (RPV) via the GDCS injection lines. Noncondensable gases that collect in the condensers during operation are purged to the suppression pool via vent lines. To reduce accumulation of radiolytic gas in the PCCS vent lines, vent line catalyst modules composed of metal parallel plates coated with catalyst are placed near the entrance of each vent line. Back-flow from the GDCS pool to the suppression pool is prevented by a loop seal in the GDCS drain line.

The RPV is contained within the drywell so that drywell pressure rises above the pressure in the wetwell (suppression pool) during a LOCA. This differential pressure initially directs the high energy blowdown fluids from the RPV break in the drywell through both the pressure

BACKGROUND (continued)

suppression pool and through the PCCS condensers. As the flow passes through the PCCS condensers, heat is rejected to the IC/PCCS pool, thus cooling the containment.

There are no isolation valves on the PCCS inlets from the drywell, or the drain lines to the GDCS pools, or the vent lines to the suppression pool. The PCCS does not have instrumentation, control logic, or power-actuated valves, and does not need or use electrical power for its operation in the first 72 hours after a LOCA. This configuration makes the PCCS fully passive because no active components are required for the system to perform its design function (Ref. 2). Long-term effectiveness of the PCCS (beyond 72 hours) is supported by a vent fan that is connected to each PCCS vent line and exhausts to the GDCS pool. The PCCS vent fans aid in the long-term removal of non-condensable gas from the PCCS for continued condenser efficiency.

Spectacle flanges in the suppression pool vent line and the GDCS drain line are used to isolate the condensers to allow post maintenance leakage tests separately from Type A containment leakage tests.

Each PCCS condenser is located in a sub-compartment of the IC/PCCS pool. During a LOCA, pool water temperature could rise to about 102°C (216°F) (Ref. 1). The steam formed will be non-radioactive and have a slight positive pressure relative to station ambient. The steam generated in the IC/PCCS pool is released to the atmosphere through large-diameter discharge vents. A moisture separator is installed at the entrance to the discharge vent lines to preclude excessive moisture carryover and loss of IC/PCCS pool water.

Each PCCS condenser is designed to remove a minimum 7.8 MWt of decay heat assuming the containment side of the condenser contains pure, saturated steam at 308 kPa absolute (45 psia) and 134°C (273°F); and, the IC/PCCS pool is at atmospheric pressure with a water temperature of 102°C (216°F).

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat-removal capacity of the Passive Containment Cooling System is adequate to maintain the containment conditions within design limits. The time

BASES

APPLICABLE SAFETY ANALYSES (continued)	history for containment pressure and temperature are calculated to demonstrate that the maximum values remains below the design limit. PCCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires six PCCS condensers to be OPERABLE. OPERABILITY of a PCCS condenser requires that all the performance and physical arrangement SRs for the PCCS condensers be met. Additionally, the isolation valve for the PCCS condenser subcompartment pool must be locked open. This ensures that the full capacity of the IC/PCCS pools is available to provide required cooling water to the PCCS condenser for at least 72 hours after a LOCA without the need for operator action. With the PCCS subcompartment isolation valve locked open, subcompartment level is maintained in accordance with the requirements in LCO 3.7.1, "Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools."
APPLICABILITY	The PCCS condensers are required to be OPERABLE in MODES 1, 2, 3, and 4 because a LOCA could cause a pressurization and heat up of containment. In MODES 5 and 6, the probability and consequences of a LOCA are reduced because of the pressure and temperature limitations of these MODES. Therefore, passive containment cooling is not required to be OPERABLE in MODES 5 and 6.
ACTIONS	<u>A.1</u> If one or more PCCS condensers are inoperable, the functional capability of the passive containment cooling is degraded. All six PCCS condensers must be made OPERABLE within 8 hours to ensure that containment cooling capacity is maintained. The Completion Time is based on engineering judgment considering the low probability of an event requiring PCCS operation. <u>B.1 and B.2</u> If the Required Action and Completion Time of Condition A are not met, functional capability of the passive containment cooling is assumed lost. Therefore, the plant must be placed

BASES

ACTIONS (continued)

in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

This SR requires periodic verification that the spectacle flanges for the vent, and drain line for each PCCS condenser are in the free flow position. This SR is required to ensure that each PCCS condenser is aligned to function properly when required.

Performance of the SR requires entry into containment. Therefore, this SR is performed prior to entering MODE 2 or 4 from MODE 5 if containment was de-inerted while in MODE 5 unless the SR was performed in the previous 92 days. This Frequency is acceptable because changing the status of the PCCS spectacle flanges requires entry into containment, is performed under administrative controls during planned maintenance activities, and is unlikely to occur inadvertently.

SR 3.6.1.7.2

This SR requires verification every 24 months that each PCCS subcompartment manual isolation valve is locked open. This SR ensures that the level in the subcompartment is the same as the level in the associated expansion pool and that the full volume of water in the IC/PCCS pools is available to each condenser. If this SR is not met, the associated PCCS condenser may not be capable of performing its design function. The 24-month Frequency is based on engineering judgment and is acceptable because the manual isolation valves between the IC/PCCS pool and the PCCS subcompartments are locked open and maintained in their correct position under administrative controls.

SR 3.6.1.7.3

This SR requires periodic verification that both modules in each PCCS condenser have an unobstructed path from the drywell inlet through the condenser tubes to both the GDCS pool through the drain line and to the suppression pool through the vent line.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency for this SR is 24 months on a STAGGERED TEST BASIS for each PCCS condenser. This Frequency requires testing one of the six PCCS condensers every 24 months, which is consistent with the normal refueling interval. The Frequency is based on engineering judgment, the simplicity of the design, and the requirement for containment access to perform the SR.

SR 3.6.1.7.4

This SR requires visual examination of each PCCS vent catalyst module and verification that there is no evidence of abnormal conditions.

The Frequency for this SR is 24 months on a STAGGERED TEST BASIS for each PCCS condenser. This frequency requires testing two of twelve vent catalyst modules every 24 months, which is consistent with the typical refueling cycle. The Frequency is based on engineering judgment, the simplicity of the design, the inerted conditions which the catalyst modules will be exposed to in their standby mode, and the requirement to access containment to perform the SR.

SR 3.6.1.7.5

This SR requires verifying performance of a representative sample of PCCS vent catalyst module plates.

The Frequency for this SR is 24 months on a STAGGERED TEST BASIS for each PCCS condenser. This Frequency requires testing two of twelve vent catalyst modules every 24 months, which is consistent with the typical refueling cycle. The Frequency is based on engineering judgment, the simplicity of the design, the inerted conditions which the catalyst modules will be exposed to in their standby mode, and the requirement to access containment to perform the SR. The representative sample consists of one plate from each PCCS vent catalyst module.

REFERENCES

1. Chapter 6.
2. Chapter 19.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Containment Oxygen Concentration

BASES

BACKGROUND	All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the containment to meet 10 CFR 50.44(c)(2). With the containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the containment for any hydrogen concentration. An event that rapidly generates hydrogen from zirconium metal water reaction could result in excessive hydrogen in containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.
APPLICABLE SAFETY ANALYSES	The Reference 1 calculations assume that the containment is inerted when a Design Basis Accident (DBA) loss of coolant accident (LOCA) occurs. Thus, the hydrogen assumed to be released to the containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the containment. The safety analyses show that the core does not uncover during the DBA LOCA and as a result, there is no fuel damage or fuel clad-coolant interaction leading to significant hydrogen generation that would result in a combustible gas condition (Ref. 1). Therefore, containment oxygen concentration does not satisfy any of the 10 CFR 50.36(c)(2)(ii) criteria. This LCO is included in accordance with NRC guidance provided in Reference 2.
LCO	The containment oxygen concentration is maintained < 4.0 v/o to maintain acceptable risk mitigation of combustible gases produced by beyond design-basis accidents involving both fuel-cladding oxidation and core-concrete interaction. The intent is to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

BASES

APPLICABILITY

The containment oxygen concentration must be within the specified limit, except as allowed by the relaxations during startup and shutdown addressed below. The containment must be inert with THERMAL POWER > 15% RTP, since this is the condition with the highest probability of an event that could lead to significant hydrogen generation.

Inerting the containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. When operating with THERMAL POWER ≤ 15% RTP, the potential for an event that generates significant hydrogen is low and the containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the containment is not inerted, are also justified. The 24-hour time period is a reasonable amount of time to allow plant personnel to perform post-startup inspections, as well as inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating with THERMAL POWER > 15% RTP, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24-hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o based on engineering judgment considering the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 15% RTP within 8 hours. The 8-hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.8.1

The containment must be determined to be inert by verifying that oxygen concentration is < 4.0 v/o. The 7-day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which would lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. Section 6.2.5.

2. NRC letter, Manny Comar to General Electric Company, "Request for Additional Information Letter No. 107 Related to ESBWR Design Certification Application," dated August 31, 2007.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND	The wetwell is a reinforced concrete vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible energy released during a reactor blowdown from Safety Relief Valve (SRV) discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the vent lines during a loss-of-coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design pressure for DBAs of 310 kPaG (45 psig). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements. The technical concerns that lead to the development of suppression pool average temperature limits are as follows: a. Assure steam condensation of the blowdown. b. Assure containment peak pressure and temperature are below design values, and c. Assure steam condensation loads are acceptable.
APPLICABLE SAFETY ANALYSES	The postulated DBA against which containment performance is evaluated is the entire spectrum of postulated pipe breaks within the containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Ref. 1 for LOCAs, and Reference 2 for stuck open relief valve). An initial pool temperature of 43.3°C (110°F) is assumed for the Reference 1 and Reference 2 analyses. Reactor shutdown at a pool temperature of 48.9°C (120°F) and vessel depressurization at a pool temperature of 54.4°C (130°F) are also assumed. Suppression pool average temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO establishes the following limits for suppression pool average temperature:

a. When THERMAL POWER is > 1% RTP and testing which adds heat to the suppression pool is not being performed, average temperature must be ≤ 43.3°C (110°F). This requirement ensures that licensing bases initial conditions are met.

b. When THERMAL POWER is > 1% RTP and testing which adds heat to the suppression pool is being performed, average temperature must be ≤ 46.1°C (115°F). This requirement ensures that the plant has testing flexibility and was selected to provide margin below the 48.9°C (120°F) limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 43.3°C (110°F) within 24 hours per Required Action A.2.

c. When THERMAL POWER is ≤ 1% RTP, average temperature must be ≤ 48.9°C (120°F). This requirement ensures that licensing bases initial conditions are met.

A limitation on the suppression pool average temperature is required to ensure that the containment conditions assumed for the safety analyses are met. This limitation is necessary so that peak containment pressures and temperatures predicted by the safety analyses do not exceed maximum allowable values during a postulated DBA or any transient that results in heatup of the suppression pool.

APPLICABILITY

Suppression pool average temperature must be maintained within specified limits in MODES 1, 2, 3, and 4 when a DBA could cause significant heatup of the suppression pool.

In MODES 5 and 6, the probability and consequences of a LOCA are reduced because Reactor Pressure Vessel (RPV) pressure and temperature are lower. Therefore, maintaining suppression pool average temperature within limits is not required in MODES 5 or 6 to ensure containment integrity.

ACTIONS

A.1 and A.2

If suppression pool average temperature is > 43.3°C (110°F) but ≤ 48.9°C (120°F), and THERMAL POWER is > 1% RTP, and testing that adds heat to the suppression pool is not being performed, then the requirements of LCO 3.6.2.1.a are not

BASES

ACTIONS (continued)

being met. Therefore, Required Action A.2 requires that suppression pool average temperature be restored to within required limits within 24 hours. Additionally, Required Action A.1 requires verification every hour that suppression pool average temperature has not exceeded limits specified in LCO 3.6.2.1.c because this temperature would require immediate entry into condition D.

The Completion Time of 24 hours to restore the temperature to within the limits of LCO 3.6.2.1.a is acceptable because significant containment cooling capability still exists and the containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. Additionally, the 24-hour Completion Time is adequate to allow the suppression pool temperature to be restored below the limit.

The Completion Time of once per hour for verification that the limits specified in LCO 3.6.2.1.c have not been exceeded is acceptable because experience has shown that pool temperature increases relatively slowly when not performing testing that adds heat to the pool. Furthermore, other indications in the control room will alert the operator to an abnormal suppression pool temperature trend and alarms will alert operators if specified limits are exceeded.

B.1

If the Required Actions and associated Completion Times of Condition A not met, suppression pool average temperature has not been restored to within limits in the required Completion Time. Therefore, the plant must be placed in a MODE in which the LCO 3.6.2.1.a does not apply. This is accomplished by reducing power to < 1% RTP within 12 hours. The 12-hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

C.1

If suppression pool average temperature is > 46.1°C (115°F), THERMAL POWER is > 1% RTP, and testing that adds heat to the suppression pool is being performed, the temporary allowance provided for suppression pool heating for testing has been exceeded. Therefore, all testing must be immediately suspended to preserve the heat absorption capability of the

BASES

ACTIONS (continued)

pool. When the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2 and D.3

If suppression pool average temperature is > 48.9°C (120°F), an automatic reactor shutdown is initiated because suppression pool temperature exceeds safety analyses assumptions. Therefore, Required Action D.1 specifies placing the reactor mode switch in the shutdown position as a manual backup to the automatic function.

If the reactor is shutdown and suppression pool average temperature > 48.9°C (120°F), the requirements of LCO 3.6.2.1.c are still not met. Therefore, Required Action D.2 requires monitoring suppression pool average temperature every 30 minutes because of the degraded capacity of the suppression pool. This completion time is acceptable because other indications in the control room will alert the operator to abnormal suppression pool temperature trends and alarms will alert operators if specified limits are exceeded. Additionally, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 5 within 36 hours.

E.1

If suppression pool average temperature is > 54.4°C (130°F), the capacity of the suppression pool is significantly degraded. Therefore, the plant must be placed in a condition in which overall plant risk is reduced. This is accomplished by placing the plant in at least MODE 5 within 12 hours. The allowed Completion Time ensures that the plant is promptly placed in a MODE in which the suppression pool is not required.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

This SR requires verification that suppression pool average temperature is within specified limits every 24 hours. The average temperature is determined automatically by instrumentation that takes an average of OPERABLE suppression pool water temperature channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)	The 24-hour Frequency for this SR is based on operating experience related to trending suppression pool average temperature changes and instrument drift during the applicable MODES and the need for assessing the proximity to the specified limits. The 24-hour Frequency is acceptable because highly reliable suppression pool temperature alarms will provide prompt notification of abnormal suppression pool average temperature.
REFERENCES	1. Section 6.2. 2. Chapter 15.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The wetwell is a reinforced concrete vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from Safety Relief Valve (SRV) discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the vent lines during a loss-of-coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure during a DBA is maintained below the design pressure of 310 kPaG (45 psig).

The suppression pool water volume is approximately 4424 m^3 (156,200 ft^3) at the normal water level of 5.45 m (17.9 ft) above pool floor.

APPLICABLE SAFETY ANALYSES

The upper and lower limits for suppression pool water level are inputs to the analyses for containment performance during postulated accidents and transients. Suppression pool level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated loads due to a DBA LOCA, and calculated loads due to SRV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

If suppression pool water level is too low, insufficient water is available to adequately condense the steam from the SRV quenchers and the main vents. The lower volume would absorb less steam energy before heating up excessively. The Passive Containment Cooling System (PCCS) vent return lines must also be submerged. Therefore, a minimum pool water level is specified.

If suppression pool water level is too high, it could result in excessive clearing loads from SRV discharges and excessive hydrodynamic loads due to a DBA LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Suppression pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that suppression pool water level be maintained ≥ 5.4 meters (17.7 feet) and ≤ 5.5 meters (18.0 feet) above the pool floor. These limits ensure that the initial conditions assumed for the safety analyses for containment are met.

APPLICABILITY

Suppression pool water level must be maintained within specified limits in MODES 1, 2, 3, and 4 when a DBA could cause significant loads on the containment. In MODES 5 and 6, the potential for SRV actuation is eliminated and the probability and consequences of LOCA are reduced because RPV pressure and temperature are lower. Therefore, maintaining suppression pool level within limits is not required to ensure containment integrity when in MODE 5 or 6.

ACTIONS

A.1

If suppression pool water level is not within specified limits, the initial conditions assumed for the safety analyses are not met. Therefore, suppression pool water level must be restored to within specified limits within 2 hours. This Completion Time is expected to be sufficient to restore suppression pool water level.

The 2-hour Completion Time is acceptable because the pressure suppression function still exists as long as the main vents, SRV quenchers, and PCCS vent return lines are covered even if water level is below the minimum level. Additionally, protection against overpressurization may still exist due to the margin in the peak containment pressure analysis even if water level is above the maximum level. This Completion Time also takes into account the low probability of an event during this interval.

B.1 and B.2

If the Required Action and Completion Time of Condition A are not met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on

BASES

ACTIONS (continued)	plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 This SR requires verification that suppression pool water level in within specified limits every 24 hours. The 24-hour Frequency for this SR is based on operating experience related to trending suppression pool water level variations and water level instrument drift during the applicable MODES and the need for assessing the proximity to the specified limits. The 24-hour Frequency is acceptable because suppression pool level alarms will provide prompt notification of abnormal suppression pool level.
REFERENCES	1. Chapter 6.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Reactor Building (Contaminated Area Ventilation Subsystem (CONAVS) Area)

BASES

BACKGROUND

The Reactor Building (RB) is a reinforced concrete structure that completely surrounds the containment (except the basemat). The RB provides an added barrier to fission product release from the containment during an accident; contains, dilutes, and holds up any leakage from the containment; and, houses safety-related systems.

The ESBWR design does not include a secondary containment; however, credit is taken for the existence of the RB Contaminated Area Ventilation Subsystem (CONAVS) areas surrounding the primary containment vessel in radiological analyses. RB HVAC system performs no safety-related function, other than the building ventilation isolation function, but credit is taken for hold up in the RB CONAVS area volume as discussed in Reference 1. The radiological dose consequences for LOCAs are based on an assumed containment leak rate of 0.35 weight percent per day. The bulk of the containment leakage is released into the RB (CONAVS area) and the RB (CONAVS area) leaks to the environment at a maximum rate of 211 scfm (Ref. 2). The remaining portion of primary leakage is assumed to leak through the Passive Containment Cooling System (PCCS) into the airspace directly above the Isolation Condenser/PCCS (IC/PCCS) pools and is quickly vented directly to the atmosphere.

The RB (CONAVS area) envelops all penetrations through the containment (except penetrations for MSIV and feedwater lines located in the main steam tunnel and IC/PCCS pools). Under accident conditions, the CONAVS area of the RB is isolated or passively sealed (e.g., water loop seals) to provide a hold up barrier. Therefore, containment isolation valve leakage as well as penetration leakage collects in the RB (CONAVS area). With low leakage and stagnant conditions, the RB (CONAVS area) provides a significant volume for hold up to enhance the basic mitigating functions provided by containment.

Automatic RB (CONAVS area) isolation dampers (other than MSIVs) are actuated by the Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) portion of

BASES

BACKGROUND (continued)

LD&IS as described in Bases for LCO 3.3.6.3, "Isolation Instrumentation," and LCO 3.3.6.4, "Isolation Actuation." The automatic RB (CONAVS area) isolation function of the LD&IS is designed to ensure that no single active component failure will prevent automatic isolation of the CONAVS area when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE.

Leakage through the MSIVs is routed through the main steamline drain lines where large volumes and surface areas provide effective mechanisms to hold up and plate out the relatively low leakage flow. Leakage through the feedwater lines and from the PCCS condensers is addressed in Reference 2 subsection 15.4.4.5.2.

The RB HVAC system does not perform an ESF/safety-related function other than the isolation function of the CONAVS served area of the RB as described above. The RB is divided into clean and contaminated radiological zones. Under normal conditions, airflow is maintained from clean to potentially contaminated areas and then routed via the respective HVAC subsystem to the reactor building/fuel building stack. Under high radiation conditions, the contaminated areas (CONAVS) and refueling and pool area HVAC (REPAVS) served areas isolate to provide a hold up volume. Stack radiation monitors monitor RB effluents for radioactivity. If the radioactivity level rises above set levels, the discharge can be routed for treatment before further release.

The compartments within the RB are designed to withstand the maximum pressure due to a high-energy line break (HELB). Each line break analyzed is a double-ended break. In this analysis, the rupture producing the greatest blowdown of mass and enthalpy in conjunction with worst case single active component failure is considered. Blowout panels between compartments provide flow paths to relieve pressure.

Personnel and equipment entrances to the RB consist of vestibules with interlocked doors and hatches. Large equipment access is by means of a dedicated, external access tower that provides the necessary interlocks. All openings through the RB boundary, such as personnel and equipment doors, are closed during normal operation and after a DBA by interlocks or administrative control. The doors are provided with position indicators and alarms, which are monitored in the control room.

BASES

APPLICABLE SAFETY ANALYSES	The radiological dose consequences for LOCAs are based on an assumed containment leak rate of 0.35 weight percent per day. The bulk of the primary containment leakage (0.34% per day) is released into the RB (CONAVS area) and leaks to the environment at a rate of 211 scfm (Ref. 2). Some credit is taken for hold up in the RB (CONAVS area) because the building is sealed during isolation. Reactor Building (CONAVS area) satisfies Criteria 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that RB (CONAVS area) OPERABILITY is maintained by keeping all RB (CONAVS area) equipment hatches closed, keeping RB (CONAVS area) access doors closed, except for entry and exit, and ensuring RB CONAVS ventilation dampers actuate when required. RB (CONAVS area) OPERABILITY also requires RB (CONAVS area) leakage to be within limits. For each RB CONAVS isolation damper, the LCO requires OPERABILITY of the required safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating."
APPLICABILITY	The RB (CONAVS area) is required to be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment and the RB (CONAVS area) provides an added barrier to fission product release from the containment during an accident. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the RB (CONAVS area) is not required to be OPERABLE in MODES 5 and 6.
ACTIONS	The ACTIONS are modified by two Notes. The first Note allows the RB (CONAVS area) boundary to be unisolated intermittently under administrative controls. This Note only applies to openings in the RB (CONAVS area) boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous

BASES

ACTIONS (continued)

communication with control room operators. This individual will have a method to rapidly close the opening and to restore the boundary to a condition equivalent to the design condition when a need for RB (CONAVS area) isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable RB (CONAVS area) boundary isolation damper. Complying with the Required Actions may allow for continued operation, and subsequent inoperable RB (CONAVS area) boundary isolation dampers are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

In the event that there are one or more penetration flow paths with one RB (CONAVS area) boundary isolation damper inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic damper, a closed manual damper, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to the RB (CONAVS area). This Required Action must be completed within the 7-day Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of an accident that requires the boundary to be isolated occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that RB (CONAVS area) penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

BASES

ACTIONS (continued)

B.1

With two RB (CONAVS area) boundary isolation dampers in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 48 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic damper, a closed manual damper, and a blind flange. The 48-hour Completion Time is reasonable because of the low probability of an accident that requires the boundary to be isolated occurring during this short time.

C.1

If the RB (CONAVS area) is inoperable for reasons other than Condition A or B, the RB (CONAVS area) must be restored to OPERABLE within 24 hours. The 24-hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining the RB (CONAVS area) boundary. This time period also ensures that the probability of an accident requiring RB (CONAVS area) OPERABILITY occurring during periods where the RB (CONAVS area) is inoperable is minimal.

D.1 and D.2

If the Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

This SR requires periodic verification that all RB (CONAVS area) equipment hatches are closed. The 31-day Frequency is acceptable because RB (CONAVS area) equipment hatches are maintained in position under administrative controls that make a mis-positioned hatch unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.1.2

This SR requires periodic verification that one RB (CONAVS area) access door in each access opening is closed, except when open for entry and exit. The 31-day Frequency is acceptable because RB (CONAVS area) access doors are monitored and alarmed to prevent mis-positioning.

SR 3.6.3.1.3

This SR requires verification every 31 days of the continuity of the required safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6 for each RB (CONAVS area) boundary isolation damper.

The 31-day Frequency is acceptable because multiple initiators for each damper are capable of actuating the associated RB (CONAVS area) boundary isolation damper. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the initiators.

This SR is modified by a Note that continuity is not required to be met for one required initiator circuit intermittently disarmed under administrative controls. This allows surveillance and maintenance with the assurance that the damper will not be inadvertently isolated. The operation of the disable/test switch in one division does not disable the RB (CONAVS area) boundary isolation damper because of the capability of the remaining required initiator(s).

SR 3.6.3.1.4

This SR requires periodic verification that RB (CONAVS area) ventilation dampers actuate on an actual or simulated isolation signal. The LOGIC SYSTEM FUNCTIONAL TESTs in LCO 3.3.6.2 and LCO 3.3.6.4 overlap this SR to provide complete testing of the safety function. The 24-month Frequency is based on engineering judgment and is acceptable based on the reliability of this type of component.

SR 3.6.3.1.5

This SR requires periodic verification that the RB (CONAVS area) exfiltration (leakage) rate is less than the limit, which is based on the assumptions in the radiological evaluations. Operating experience has shown that containment boundary designs similar to the RB (CONAVS area) boundary

BASES

SURVEILLANCE REQUIREMENTS (continued)	usually pass this Surveillance when performed at the 24-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.
REFERENCES	1. Chapter 6. 2. Chapter 15.

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B 3.7 PLANT SYSTEMS

B 3.7.1 Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools

BASES

BACKGROUND

The Ultimate Heat Sink (UHS) is the IC/PCCS Pools that transfer heat from the Isolation Condenser System (ICS) and the PCCS to the atmosphere (Ref. 1). The ICS removes heat from the Reactor Coolant System (RCS) following RCS isolation, a loss of feedwater or a Loss of Coolant Accident (LOCA). The PCCS removes heat from the containment following a LOCA or any transient that releases heat to the containment.

The IC/PCCS pools are located above and outside the containment boundary, directly above the drywell top slab. The condenser module associated with each ICS train and PCCS condenser is submerged in a separate subcompartment of the IC/PCCS pools. Subcompartments (i.e., pools) P3A, P3B, P3C, and P3D contain the condenser modules for the ICS trains. Subcompartments P4A, P4B, P4C, P4D, P4E, and P4F contain the condenser modules for the PCCS condensers.

Heat from the ICS and PCCS condensers is transferred to water in the associated subcompartment causing the water in the subcompartment to boil. Following reactor pressure vessel (RPV) isolation or a LOCA, subcompartment water temperature could rise to about 102°C (216°F). The steam formed will be non-radioactive and have a slight positive pressure. The steam from each subcompartment collects in the common air/steam space above the subcompartments and IC/PCCS pools. The steam is then released to the atmosphere through two large-diameter discharge vents located on opposite sides of the expansion pools. A moisture separator is installed at the entrance to the discharge vent lines to preclude excessive moisture carryover and loss of IC/PCCS pool water. No forced circulation equipment is required for operation (Refs. 2 and 3).

To support decay heat removal for 72 hours without operator action, water must be supplied to the ICS and PCCS subcompartments to replace the water lost by boiling. This water is supplied from the two IC/PCCS expansion pools, the equipment pool, and the reactor well pool.

BASES

BACKGROUND (continued)

Each ICS and PCCS subcompartment is connected to its associated expansion pool by a manually operated valve located below the water level, which allows makeup water from the expansion pool to flow into the bottom of the subcompartment. The subcompartment isolation valves are normally locked open so that the full inventory of the associated expansion pool is available to any subcompartment. The subcompartment isolation valves can be closed to isolate a subcompartment allowing it to be emptied for maintenance of the condenser.

In addition to the ICS and PCCS subcompartments, each expansion pool is partitioned into three parts. Manually operated valves, which are normally locked open, separate each partition.

The equipment pool is connected to the reactor well pool through the reactor well gate, which is not installed during normal plant operation. By connecting the equipment pool and reactor well pool to the expansion pools, the volume of water available to the ICS and PCCS subcompartments is sufficient to support decay heat removal for 72 hours without operator action or the need to replenish the water in the expansion pools.

The equipment pool and reactor well pool are normally isolated from the expansion pools because the equipment pool and reactor well are maintained at a higher water level than the expansion pools. Each of the two expansion pools is connected to the equipment pool by two piping connections. One connection to each expansion pool is isolated by a squib-actuated cross-connect valve and the other connection is isolated by a fail-as-is double acting pneumatic piston cross-connect valve. Each connection also includes a manually operated valve, which is normally locked open. Opening one piping connection from the equipment pool to each expansion pool provides the required makeup from the equipment pool to the expansion pools.

The Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) System controls the initiation signals and logic for the opening of the IC/PCCS expansion pool-to-equipment pool cross-connect valves. SSLC/ESF is a four division, separated protection logic system designed to provide a very high degree of assurance to both ensure initiation when required and prevent inadvertent initiation. The input and output trip determination is based upon a two-out-of-four logic arrangement. Each division of SSLC/ESF

BASES

BACKGROUND (continued)

is configured such that all functions (e.g., the digital trip module (DTM) function and voter logic unit (VLU) function) are implemented in triply redundant processors to support the requirement that single divisional failures cannot result in inadvertent actuation.

Four separate instrument channels are used to monitor each IC/PCCS inner expansion pool level. Signals from sensors are multiplexed at the divisional level and the triply redundant sensor data is then transmitted to the SSLC/ESF triply redundant digital trip module (DTM) function for setpoint comparison. The output of each divisional DTM function (a trip/no-trip condition) is routed to all four divisional triply redundant VLU functions such that each divisional VLU function receives input from each of the four divisional DTM functions.

For maintenance purposes and added reliability, each DTM function has a division of sensors bypass such that all instruments in that division will be bypassed in the trip logic at the VLU functions. Thus, each VLU function will be making its trip decision on a two-out-of-three logic basis for each variable. It is possible for only one division of sensors bypass condition to be in effect at any time.

The processed trip signal from its own division and trip signals from the other three divisions are processed in the triply redundant VLU function for two-out-of-four voting. Each pair of IC/PCCS expansion pool-to-equipment pool cross-connect valves receive an open signal on low level in the associated inner expansion pool.

Each expansion pool-to-equipment pool cross-connect squib valve is equipped with four squib initiators. Each expansion pool-to-equipment pool cross-connect pneumatic valve is equipped with four solenoid valves (i.e., initiators). A signal to any of the four initiators will actuate the associated cross-connect valve. Three of the four initiators on each valve are actuated by SSLC/ESF. As such, at least two of the three safety-related initiators on each valve will be associated with divisions required by LCO 3.8.6, "Distribution Systems - Operating." The fourth initiator is actuated by the Diverse Protection System (DPS), which is designed to mitigate digital protection system common mode failures.

BASES

BACKGROUND (continued)	Cooling and clean up of IC/PCCS pool water is performed by Fuel and Auxiliary Pools Cooling System (FAPCS). The FAPCS includes a separate subsystem with its own pump, heat exchanger, and water treatment unit that is dedicated for cooling and cleaning of the IC/PCCS pools to prevent radioactive contamination of the IC/PCCS pools. The FAPCS includes flow paths for post-accident make-up water transfer, from the fire protection system and off-site water supply sources to the IC/PCCS pools (Ref. 1).
APPLICABLE SAFETY ANALYSES	In the event of a LOCA, the passive PCCS is required to maintain the SAFETY containment peak pressure and temperature design limits for at least 72 hours after the LOCA without operator action (Ref. 3). In the event of reactor isolation or a station blackout, the ICS must maintain the reactor coolant system pressure and temperature below design limits and remove core decay heat for at least 72 hours after reactor isolation without operator action (Ref. 2). The IC/PCCS pools are also needed as a heat sink for the ICS condensers when ICS is used as a backup to the Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System for decay heat removal when shutdown. The IC/PCCS pools satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that the IC/PCCS pools are OPERABLE. Operability requires the IC/PCCS pools be maintained within specified limits for minimum level and maximum average temperature. To ensure that the total volume of water in the IC/PCCS pools is available to the ICS and PCCS condensers, manual isolation valves between the partitions within each expansion pool and between the equipment pool and each expansion pool must be locked open. Cross-connect valves between the equipment pool and the expansion pools must open automatically on a low water level signal from the associated expansion pool. Additionally, the reactor well gate, which connects the reactor well to the equipment pool, must be removed.

BASES

LCO (continued)	OPERABILITY of the expansion pool-to-equipment pool cross-connect function requires OPERABILITY of three channels of safety-related IC/PCCS expansion pool level instrumentation in each pool and three safety-related actuation logic divisions. OPERABILITY of an instrumentation channel requires OPERABILITY of the instrumentation from the input variable sensor through the DTM function. Each instrumentation channel must have its setpoint in accordance with Specification 5.5.11, "Setpoint Control Program (SCP)." OPERABILITY of an actuation logic division requires OPERABILITY of the circuitry from the output of the DTM function through the VLU function, the timers, and the load drivers. OPERABILITY of each expansion pool-to-equipment pool squib cross-connect valve and pneumatic cross-connect valve requires OPERABILITY of the DPS initiator and two safety-related initiators. The required safety-related channels, divisions, and initiators are those associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating." OPERABILITY of the instrumentation and actuation logic associated with the DPS initiators is addressed by LCO 3.3.8.1, "Diverse Protection System (DPS)."
APPLICABILITY	The IC/PCCS pools are required to be OPERABLE in MODES 1, 2, 3, and 4 because the PCCS and ICS could be required to respond to an event that caused pressurization and heat up of containment or the ICS could be required to respond to an RPV isolation. Requirements for the IC/PCCS expansion pools in MODE 5 are determined by the requirements of LCO 3.5.5, "Isolation Condenser System (ICS) -Shutdown."
ACTIONS	<u>A.1</u> This Condition applies when one or both expansion pools have one equipment pool cross-connect valve DPS initiator inoperable. In this Condition, required safety-related initiators will actuate the expansion pool-to-equipment pool cross-connect valves needed to support decay heat removal for 72 hours without operator action concurrent with any

BASES

ACTIONS (continued)

additional single failure, including digital protection system common mode failures.

In this Condition, the inoperable expansion pool-to-equipment pool DPS initiators must be restored to OPERABLE status the next time the plant is placed in MODE 5 (i.e., prior to entering MODE 2 or MODE 4 from MODE 5). This Completion Time is acceptable because the remaining DPS initiator and the required safety-related initiators will actuate the minimum number of expansion pool-to-equipment pool cross-connect valves required to support decay heat removal for 72 hours concurrent with any additional single failure.

B.1

This Condition applies when one or both expansion pools have both equipment pool cross-connect valve DPS initiators inoperable. In this Condition, required safety-related initiators will actuate the minimum expansion pool-to-equipment pool cross-connect valves assumed in the design basis analysis concurrent with any additional single failure. However, design features intended to mitigate the possibility of digital protection system common mode failures are not available.

In this Condition, at least one DPS initiator in each affected expansion pool must be restored to OPERABLE status within 30 days. This Completion Time is acceptable because the required safety-related initiators will actuate the minimum number of expansion pool-to-equipment pool cross-connect valves required to support decay heat removal for 72 hours without operator action concurrent with any additional single failure.

C.1

This Condition applies when one or both IC/PCCS expansion pools have one equipment pool connection line inoperable for reasons other than Condition A. In this Condition, failure of an additional expansion pool-to-equipment pool connection line could result in the need for operator action to re-fill the IC/PCCS pool in less than 72 hours following any event that requires either PCCS or ICS for decay heat removal.

In this Condition, the expansion pool-to-equipment pool connection line(s) must be restored to OPERABLE status within 30 days. This Completion Time is acceptable based on

BASES

ACTIONS (continued)

engineering judgment considering that substantial decay heat removal capacity would remain available even if an additional expansion pool-to-equipment pool connection line failed and the low probability of a failure of an additional expansion pool-to-equipment pool connection line failure in conjunction with an event that requires either PCCS or ICS for decay heat removal.

D.1

With one required IC/PCCS expansion pool level instrumentation channel inoperable, the affected required channel must be restored to OPERABLE status within 20 hours. In this Condition, actuation trip capability is maintained but a single failure cannot be accommodated.

The 20-hour Completion Time is acceptable based on engineering judgment considering the redundancy of the instrumentation design and the low probability of an event requiring actuation of the expansion pool-to-equipment pool cross-connect during this period.

Alternatively, if the instrumentation channel cannot be restored to OPERABLE status, Condition G must be entered and its Required Action taken when the Completion Time of Required Action D.1 expires.

It should be noted that if more than one required instrumentation channel is inoperable, then the cross-connect may not actuate as required; therefore, the IC/PCCS Pools must be declared inoperable and Condition F must be entered.

E.1

Condition E exists when one required IC/PCCS expansion pool-to-equipment pool cross-connect actuation division is inoperable. In this Condition, actuation trip capability is maintained but a single failure cannot be accommodated. The 20-hour Completion Time is acceptable based on engineering judgment considering the redundancy of the actuation design and the low probability of an event requiring cross-connect actuation during this period.

Alternatively, if the actuation division cannot be restored to OPERABLE status, Condition G must be entered and its Required Action taken when the Completion Time of Required Action E.1 expires.

BASES

ACTIONS (continued)

It should be noted that if more than one required actuation division is inoperable, then the cross-connect may not actuate as required; therefore, the IC/PCCS Pools must be declared inoperable and Condition F must be entered.

F.1

If the IC/PCCS pool is inoperable for reasons other than Condition A, B, C, D, or E, then the ICS and PCCS may not be capable of performing their required safety function and the initial conditions used in the analyses in References 2 and 3 may not be met. Required Action F.1 requires that the IC/PCCS pools be restored within 8 hours. The Completion Time of 8 hours is acceptable based on the remaining heat removal capability of the IC/PCCS pools and the alternate methods for providing makeup to the IC/PCCS pools.

G.1 and G.2

If the Required Action and associated Completion Time of Condition A, B, C, D, E, or F is not met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Times are reasonable, based on plant design, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of the IC/PCCS expansion pool level instrumentation has not occurred.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

SURVEILLANCE REQUIREMENTS (continued)

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Surveillance Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK every 12 hours supplements less formal, but more frequent checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.7.1.2 and 3.7.1.3

This SR requires verification every 24 hours that the water levels in each expansion pool and the water level in the equipment pool or reactor well are within specified limits. These levels are necessary to ensure that the volume of water in the IC/PCCS pools is sufficient to support decay heat removal via the ICS and/or the PCCS for 72 hours without the need to replenish the water in the expansion pools. The 24 hour frequency is acceptable because abnormal water levels are identified by alarms and indication in the control room.

SR 3.7.1.3 is modified by a Note that specifies that this SR is not required to be met in MODES 3 and 4. Considering the reduced decay heat loads following events initiated after the reactor is shut down, isolation of these pools from the IC/PCCS expansion pools when in Modes 3 and 4 will not result in a significant reduction in the 72 hours assumed available to provide makeup to the IC/PCCS pools.

SR 3.7.1.4

This SR requires verification every 24 hours that the bulk average temperature of the available IC/PCCS pools is ≤ 43.3°C (110°F). The bulk average temperature is calculated based on the volume and temperature of the water in the expansion pools, the connected ICS and PCCS subcompartments (isolated subcompartments are addressed in LCO 3.5.4, "Isolation Condenser System (ICS) - Operating" and LCO 3.6.1.7, "Passive Containment Cooling System (PCCS)," respectively), the equipment pool, and the reactor well. The water volume in any isolated subcompartments, or the equipment pool when inoperabilities render it unavailable, are not averaged to meet the requirements of SR 3.7.1.4.

SURVEILLANCE REQUIREMENTS (continued)

This value for the average temperature of the IC/PCCS pools is an assumption in the analyses described in References 2 and 3 that determined that the heat sink capacity of the IC/PCCS pools is sufficient to support decay heat removal for 72 hours without the need to replenish the water in the expansion pools. The 24-hour frequency is acceptable because operators will be promptly alerted to abnormal water temperatures by alarms and indication in the control room.

SR 3.7.1.5

This SR requires periodic verification that the supply pressure to the expansion pool-to-equipment pool pneumatic cross-connect valve accumulators (i.e., Instrument Air System (IAS)) is greater than or equal to the specified limit. An accumulator on each expansion pool-to-equipment pool pneumatic cross-connect valve provides pneumatic pressure for valve actuation. The 31-day Frequency is acceptable because IAS low-pressure alarms provide prompt notification of an abnormal pressure in the IAS.

SR 3.7.1.6

This SR requires a periodic verification of the continuity of the DPS initiator and two safety-related initiators associated with DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems - Operating," for each expansion pool-to-equipment pool isolation cross-connect valve.

The 31-day Frequency is acceptable because either of the expansion pool-to-equipment pool lines for each expansion pool is capable of performing the required function. Additionally, an alarm will provide prompt notification of loss of circuit continuity for the required initiators in each expansion pool-to-equipment pool cross-connect valve.

This SR is modified by a Note that continuity is not required to be met for one required initiator intermittently disabled under administrative controls. This allows the continuity monitor to be tested and allows surveillance and maintenance with the assurance that the valve will not be opened inadvertently.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.7

A CHANNEL FUNCTIONAL TEST is performed on each required IC/PCCS expansion pool level instrumentation channel to ensure the entire channel will perform the intended function. This test ensures a complete CHANNEL FUNCTIONAL TEST of required instrument channels from the sensor input through the DTM function.

The SSLC/ESF is cyclically tested from the sensor input point to the logic contact output by online self-diagnostics. The self-diagnostic capabilities include microprocessor checks, system initialization, watchdog timers, memory integrity checks, input/output (I/O) data integrity checks, communication bus interface checks, and checks on the application program (checksum).

The Frequency of 31 days is based on the reliability of the instrumentation channels.

SR 3.7.1.8

This SR requires verification every 24 months that the manual isolation valve on each expansion pool-to-equipment pool line and between each IC/PCCS expansion pool partition is locked open. This SR is needed to ensure that the full volume of water in each expansion pool is available to the ICS and PCCS subcompartments. If this SR is not met, the ICS and PCCS may not be capable of performing their design functions. The 24-month Frequency for this SR is based on engineering judgment and is acceptable because the manual isolation valves between the IC/PCCS pool partitions are locked open and maintained in their correct position under administrative controls.

SR 3.7.1.9

This SR requires verification every 24 months that the reactor well-to-equipment pool gate is not installed. This SR is necessary to ensure that the volume of water in the reactor well is available to the ICS and/or the PCCS condensers. The volume of water in the reactor well is needed to support decay heat removal for 72 hours without the need to replenish the water in the expansion pools. The 24-month frequency is acceptable because installation of the reactor well-to-equipment pool gate is a significant change in plant status that would not occur without the cognizance of the operators.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that specifies that this SR is not required to be met in MODES 3 and 4. Considering the reduced decay heat loads following events initiated after the reactor is shutdown, isolation of this pool from the IC/PCCS expansion pools when in Modes 3 and 4 will not result in a significant reduction in the 72 hours assumed available to provide makeup to the IC/PCCS pools.

SR 3.7.1.10

This SR requires verification every 24 months that each cross-connect valve between the IC/PCCS expansion pools and the equipment pool actuates on an actual or simulated automatic initiation signal. At least one of the two cross-connect valves that isolate each expansion pool from the equipment pool must be open to ensure that the volume of water in the equipment pool and the reactor well is available to the ICS and/or the PCCS condenser. The volume of water in the reactor well and the equipment pool is needed to support decay heat removal for 72 hours without the need to replenish the water in the expansion pools. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.7.1.12 and LCO 3.3.8.1 overlap this SR to provide complete testing of the assumed safety function.

This 24-month Frequency is consistent with the normal refueling interval. This interval will allow the SR to be performed during a plant outage. This SR is modified by a Note that excludes valve actuation as a requirement for this SR to be met. This is acceptable because the valves are subject to the Inservice Test Program.

This SR is modified by a Note that specifies that this SR not required to be met in MODES 3 and 4. Considering the reduced decay heat loads following events initiated after the reactor is shutdown, isolation of this pool from the IC/PCCS expansion pools when in Modes 3 and 4 will not result in a significant reduction in the 72 hours assumed available to provide makeup to the IC/PCCS pools.

SR 3.7.1.11

This SR requires a CHANNEL CALIBRATION of IC/PCCS expansion pool level instrumentation channels that actuate the expansion pool-to-equipment pool squib cross-connect valves and pneumatic cross-connect valves. CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured

SURVEILLANCE REQUIREMENTS (continued)

parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the required nominal trip setpoint within the "as-left tolerance" to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the Setpoint Control Program. The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.7.1.12

This SR requires performance of a LOGIC SYSTEM FUNCTIONAL TEST for the logic associated with automatic opening of the IC/PCCS expansion pool-to-equipment pool cross-connect valves. The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required logic for a specific division.

The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24-month Frequency.

SR 3.7.1.13

This SR requires verification that each ICS and PCCS pool subcompartment has an unobstructed path for steam release through moisture separator to the atmosphere. This SR is needed to ensure that steam formed in the ICS and PCCS subcompartments will be properly vented to the atmosphere. The Frequency is based on engineering judgment and the simplicity of the design. This Frequency of 48 months on a STAGGERED TEST BASIS for the flow path associated with each moisture separator is acceptable because the flow path from the ICS subcompartments to the expansions pool area and through the moisture separators will be verified whenever the ICS is used.

BASES

REFERENCES

1. Chapter 9.
2. Chapter 5.
3. Chapter 6.

B 3.7 PLANT SYSTEMS

B 3.7.2 Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)

BASES

BACKGROUND

NAPS COL 16.0-1-A 3.7.2-1

The CRHAVS trains, the CRHA boundary, and the CRHA heat sinks provide a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity or smoke.

The CRHAVS includes two independent and redundant CRHAVS trains that provide pressurization and radiologically filtered air to maintain control room habitability during a radiological emergency or loss of preferred power. Each CRHA train each includes: one 100% capacity Emergency Filtration Unit (EFU); two 100% capacity safety-related EFU fans in parallel; and four electrically operated, normally closed discharge EFU isolation dampers, which are mounted in a parallel configuration of two dampers in series. Each EFU fan and an associated set of dampers in series are powered from the same electrical division. Failure of one EFU fan or the associated set of dampers does not affect the operation of the other set in the same CRHA train. If flow detectors installed in the EFU discharge duct detect low flow, the operating fan motor is deenergized, its electrically operated discharge dampers are closed, a stand-by (second in the unit) fan motor is energized and its electrically operated discharge dampers are opened. If the discharge flow is not sufficiently improved or if radiation is detected downstream of the EFU, the affected CRHAVS train is automatically disengaged and the second train is energized, following the protocol described above. Each EFU consists of a medium efficiency filter, a high efficiency particulate air (HEPA) filter, a carbon adsorption filter, and a post-filter downstream of the carbon filter. The EFUs are maintained in accordance with Specification 5.5.13, "Ventilation Filter Testing Program."

The CRHA boundary confines the spaces that control room occupants inhabit to control the unit during normal and accident conditions. The CRHA boundary is the combination of walls, floor, roof, ducting, doors, penetrations, and equipment that physically form the CRHA. The CRHA boundary includes safety-related, air operated isolation dampers connected in series, which isolate the control room main air ventilation duct, the smoke purge intake duct, the

BACKGROUND (continued)

smoke purge exhaust duct, and the restroom exhaust duct. Because the air-operated dampers in each redundant pair are in series, either damper can close the airflow path. Each set of dampers is controlled by four independent solenoids, which ensures that the safety-related function of the system can be performed with the loss of any two divisions of power.

The CRHA boundary is maintained in accordance with Specification 5.5.12, "Control Room Habitability Area (CRHA) Boundary Program," to ensure that the inleakage of unfiltered air into the CRHA will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRHA occupants.

The CRHA heat sinks maintain CRHA temperature following loss of normal CRHA cooling because the CRHA heat loads are passively dissipated to the heat sinks. The CRHA heat sinks consist of three groups: the CRHA (i.e., the CRHA walls, floor, ceiling, interior walls), adjacent corridors, and HVAC chases; adjacent Q-DCIS and N-DCIS equipment rooms and electrical chases; and, adjacent HVAC equipment rooms and safety portions of the CRHA rooms. When the temperature of each CRHA heat sink is maintained within the specified limit, the CRHA heat sinks are sufficient to limit the CRHA temperature to 33.9°C (93°F).

CRHA Recirculation air-handling units (AHUs) provide normal cooling to the CRHA whenever offsite or onsite AC power is available. During the first two hours after a loss of preferred power (LOPP), the recirculation AHU fans and associated auxiliary cooling units are powered from a nonsafety-related battery. If an ancillary diesel generator is available, power for a recirculation AHU fan and auxiliary cooling unit can be provided indefinitely during a CRHA isolation event that includes a LOPP. However, if the Recirculation AHUs are not available during the LOPP, safety-related temperature sensors with two-out-of-four logic automatically trip the power to selected N-DCIS components in the MCR to reduce the N-DCIS heat load.

CRHAVS trains are actuated by the Safety System Logic and Control System/Engineered Safety Features (SSLC/ESF) described in the Bases for LCO 3.3.7.1, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Instrumentation" and LCO 3.3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Actuation." An actuation signal starts one EFU fan in the EFU

BACKGROUND (continued)

train that is designated as the primary, opens the associated EFU isolation dampers, closes the normal air supply duct and restroom exhaust safety-related isolation dampers, and stops the nonsafety-related normal air supply fans. Power to each of the four EFU fans (two in each CRHA train) and associated dampers and the four initiators for each pair of CRHA boundary dampers is supplied from a different division of the DC and Uninterruptible AC Electrical Power Distribution. As such, no single active component failure will prevent automatic initiation and successful operation of the minimum required CRHAVS components when any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution and the associated instrumentation divisions are OPERABLE.

The CRHAVS is designed to maintain a habitable environment in the CRHA for 72 hours continuous occupancy after a design basis accident (DBA) concurrent with a loss of all onsite and offsite AC power and, upon recovery of onsite or offsite AC power, for an additional 27 days continuous occupancy, without exceeding 0.05 Sv (5 rem) total effective dose equivalent (TEDE). Controls to manually isolate the CRHA and to manually actuate CRHAVS following indication of a radiological event (indicative of conditions that could result in radiation exposure to CRHA occupants) are provided. CRHAVS operation in maintaining CRHA habitability is discussed in Section 6.4 and Section 9.4.1 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the CRHAVS to maintain the habitability of the CRHA is an explicit assumption for the safety analyses presented in Chapter 6 and Chapter 15, (Refs. 1 and 3, respectively). The isolation mode of the CRHAVS is assumed to operate following a DBA. The radiological dose to CRHA occupants as a result of various DBAs is summarized in Reference 3. No single active failure will cause the loss of outside air to the CRHA. The CRHAVS provides protection from smoke to the CRHA occupants. The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRHA occupants to control the reactor either from the main control room or from the remote shutdown panels (Ref. 2).

NAPS COL 16.0-1-A 3.7.2-1

APPLICABLE SAFETY ANALYSES (continued)

CRHA heat sinks in the CRHA and adjacent spaces must be maintained consistent with the assumptions in Reference 2 to ensure that the CRHA temperature can be maintained for 72 hours following an event that includes loss of CRHAVS cooling.

The CRHAVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

OPERABILITY of the CRHAVS requires: OPERABILITY of two redundant one hundred percent capacity trains of the CRHAVS; OPERABILITY of the CRHA boundary; and OPERABILITY of the CRHA heat sinks.

Each CRHAVS train is OPERABLE when:

a. One EFU fan and the two associated EFU isolation dampers are OPERABLE and associated with a DC and Uninterruptible AC Electrical Power Distribution Division required by LCO 3.8.6, "Distribution Systems – Operating," and LCO 3.8.7, "Distribution Systems – Shutdown,"

b. The EFU HEPA filter and carbon adsorber are not excessively restricting flow and are capable of performing their filtration functions, and

c. Both EFU fan backdraft dampers are OPERABLE.

The standby EFU fan and associated EFU isolation dampers in each CRHAVS train are not required for CRHAVS train OPERABILITY.

The CRHA boundary is OPERABLE when:

a. CRHA boundary is maintained in accordance with Specification 5.5.12, "Control Room Habitability Area (CRHA) Boundary Program,"

b. The CRHA boundary isolation dampers (excluding the EFU isolation dampers associated with the EFU trains) are OPERABLE or one of the dampers in the flow path is closed, and

c. The CRHA boundary isolation dampers associated with the EFU trains are closed when the associated EFU fans are not running.

BASES

LCO (continued)	The CRHA heat sinks are OPERABLE when the CRHA and adjacent spaces are maintained within the limits in SR 3.7.2.1 to ensure that the CRHA temperature can be maintained for 72 hours following an event that includes loss of CRHAVS cooling. The LCO is modified by a Note allowing the CRHA boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRHA boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRHA. This individual will have a method to rapidly close the opening and to restore the CRHA boundary to a condition equivalent to the design condition when a need for CRHA isolation is indicated.
APPLICABILITY	In MODES 1, 2, 3, and 4, the CRHAVS must be OPERABLE to ensure that the CRHA will remain habitable during and following a DBA, since the DBA could lead to a fission product release. In MODES 5 and 6, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CRHAVS OPERABLE is not required in MODES 5 or 6, except during operations with a potential for draining the reactor vessel (OPDRVs), which is a situation under which significant radioactive releases can be postulated.
ACTIONS	<u>A.1 and A.2</u> Condition A represents a potential for degradation of the CRHA passive heat sink. The ACTIONS provide a tiered response that focuses on returning the affected heat sink area average air temperature(s) to within the established design limit and restoring the CRHA passive heat sink to OPERABLE status in a reasonable time period. When the average temperature of one or more CRHA heat sink(s) is greater than the limit specified in SR 3.7.2.1, Required Action A.1 requires that the average air temperature of each

ACTIONS (continued)

CRHA heat sink be restored to within the limit within 8 hours. The 8-hour Completion Time is acceptable based on engineering judgment to evaluate and repair any discovered inoperabilities or provide an alternate means of cooling the affected CRHA heat sink area to restore CRHA heat sink average air temperatures to within limits.

Required Action A.2 requires that the average temperature of each CRHA heat sink be restored to within limits within 24 hours. The 24-hour Completion Time is acceptable based on engineering judgment to determine that the affected CRHA heat sink structural materials temperatures are within limits.

Restoration of the CRHA heat sinks is verified by administrative evaluation considering the length of time and extent of the CRHA heat sink average air temperature excursion outside of limits, or by direct measurement of the CRHA heat sink area structural materials temperatures.

While in this Condition, the unit is more vulnerable to a trip of selected N-DCIS components in the MCR. It is, therefore, appropriate that the unit operators' attention be focused on minimizing the potential impact of a loss of selected N-DCIS components by stabilizing the unit and restoring the affected heat sink area temperatures to within limits. In addition to limiting the degradation of the CRHA heat sink and restoring temperatures to within limits, the Completion Times of Required Actions A.1 and A.2 minimize the risk associated with the potential for loss of selected N-DCIS components during a plant transient associated with a required shutdown.

B.1, B.2, and B.3

NAPS COL 16.0-1-A 3.7.2-1

If the unfiltered inleakage of potentially contaminated air past the CRHA boundary can result in CRHA occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRHA occupants from smoke, the CRHA boundary is inoperable. The CRHA boundary must be restored to OPERABLE status within 90 days.

During the period that the CRHA boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRHA occupants from the potential hazards of a radiological event

BASES

ACTIONS (continued)

NAPS COL 16.0-1-A 3.7.2-1

or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRHA occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRHA occupants are protected from smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRHA boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRHA occupants within analyzed limits while limiting the probability that CRHA occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRHA boundary.

C.1

With one CRHAVS train inoperable for reasons other than Condition A or B, the inoperable CRHAVS train must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRHAVS train is adequate to perform the CRHA occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE train could result in loss of CRHAVS function. The 7-day Completion Time is based on engineering judgment considering the low probability of a DBA occurring during this time period and that the remaining train can provide the required capabilities.

D.1 and D.2

If the Required Action and associated Completion Time of Condition A, B, or C are not met when in MODE 1, 2, 3, or 4 or if two CRHAVS trains are inoperable when in MODE 1, 2, 3, or 4 for reasons other than Condition A or B, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The Completion Time is reasonable, based on plant design, to

BASES

ACTIONS (continued)

reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If the Required Action and associated Completion Time of Condition A or B are not met during OPDRVs or if two CRHAVS trains are inoperable during OPDRVs, action must be taken to immediately suspend activities that represent a potential for releasing radioactivity that might require isolation of the CRHA. This places the unit in a condition that minimizes risk.

Applicable actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

F.1 and F.2

If the Required Action and associated Completion Time of Condition C are not met during OPDRVs (i.e., the inoperable CRHAVS train cannot be restored to OPERABLE status), the OPERABLE CRHAVS train may be placed in the isolation mode. This action ensures that the remaining train is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action F.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the CRHA. This places the unit in a condition that minimizes risk. Applicable actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies every 24 hours that the average temperature for each CRHA heat sink is within established design limits (Ref. 4). The CRHA heat sinks and associated design limits for initial temperature are as shown in Table B 3.7.2-1. The CRHA heat sinks consist of three groups: the CRHA (i.e., the CRHA walls, floor, ceiling, interior walls), adjacent corridors, and HVAC chases; adjacent Q-DCIS and N-DCIS equipment rooms and electrical chases; and, adjacent HVAC

SURVEILLANCE REQUIREMENTS (continued)

equipment rooms and safety portions of the CRHA rooms. A CRHA heat sink temperature is assumed to be within the specified limit if the average of the air temperature in the heat sink is within the specified limit since the last performance of the surveillance. This is acceptable because the temperature change of the CRHAVS heat sink area structural materials will lag behind the temperature change of the CRHA heat sink area average air temperature with respect to increasing temperature. Therefore, CRHA heat sink area average air temperature outside of the specified limit provides a conservative indication of a potential degradation of the CRHA heat sink. In addition, the CRHA heat up calculation assumes that the CRHA heat sink area structural materials are in equilibrium with the CRHA heat sink area average air temperature.

The surveillance limit for each of the CRHA heat sinks is equal to or more conservative than the initial temperature assumed in the CRHA thermal analysis. This SR ensures that the nonsafety-related recirculation AHUs are performing as required to maintain initial CRHA heat sink temperatures consistent with the assumptions in the safety analysis, which will ensure that the CRHA temperature will not exceed the required conditions after loss of CRHAVS cooling.

The 24 hour Frequency is acceptable based on the availability of temperature indication in the main control room and the slow change in the actual heat sink temperature following a change in the air temperature being monitored.

SR 3.7.2.2

This SR verifies that a CRHAVS train in a standby mode starts on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each train once every month provides an adequate check on this system. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two train redundancy available.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.3

This SR verifies that the required CRHAVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, carbon adsorber efficiency, minimum system flow rate, and the physical properties of the activated carbon (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.2.4

This SR verifies that each CRHA isolation damper closes and each CRHAVS train starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.2, "Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS) Actuation," overlaps this SR to provide complete testing of the safety function.

The 24 month Frequency is based on the normal refueling frequency, and is consistent with the Frequency of the surveillances performed for the actuation instrumentation.

SR 3.7.2.5

This SR verifies that the selected main control room N-DCIS electrical loads automatically de-energize on an actual or simulated initiation signal. Temperature sensors with two-out-of-four logic automatically trip the power to selected N-DCIS components in the main control room (MCR) to reduce the heat load if the AHUs are not powered.

The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.2 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the normal refueling frequency, and is consistent with the Frequency of the surveillances performed for the actuation instrumentation.

SR 3.7.2.6

This SR requires a CHANNEL CALIBRATION of the main control room temperature instrumentation channels that automatically trip the power to N-DCIS components in the main control room (MCR) to reduce the heat load if the AHUs are not powered. CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel

BASES

SURVEILLANCE REQUIREMENTS (continued)

responds to the measured parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the required nominal trip setpoint within the "as-left tolerance" to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the Setpoint Control Program. The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.7.2.7

NAPS COL 16.0-1-A 3.7.2-1

This SR verifies the OPERABILITY of the CRHA boundary by testing for unfiltered air inleakage past the CRHA boundary and into the CRHA. The details of the testing are specified in the Control Room Habitability Area (CRHA) Boundary Program. The CRHA is considered habitable when the radiological dose to CRHA occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRHA occupants are protected from smoke. This SR verifies that the unfiltered air inleakage into the CRHA is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRHA boundary to OPERABLE status provided mitigating actions can ensure that the CRHA remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 5) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 6). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 7). Options for restoring the CRHA boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRHA boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRHA boundary has been restored to OPERABLE status.

BASES

REFERENCES

1. Section 6.4.

2. Section 9.4.1.

3. Section 15.4.

4. Section 3H.

5. Regulatory Guide 1.196.

6. NEI 99-03, "Control Room Habitability Assessment," June 2001.

7. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

Table B 3.7.2-1

HEAT SINK GROUP	ESTABLISHED DESIGN TEMPERATURE
CRHA Heat Sink Group 1	
Control Room Habitability Area: Main control room panel Rooms: No 3270, 3272, 3271, 3201, 3202, 3273, 3206, 3205, 3204, 3275, 3207, 3208	23.3ºC (74ºF)
Corridors:[1] Rooms 3100, 3101 and Rooms 3200, 3203, 3277, 3274	25.6ºC (78ºF)
HVAC chases:[1] Rooms 3251, 3260	25.6ºC (78ºF)
CRHA Heat Sink Group 2	
Q-DCIS equipment rooms: Rooms No 3110, 3120, 3130 and 3140	25.6ºC (78ºF)
N-DCIS equipment rooms: Rooms 3301, 3302, 3303, 3300	25.6ºC (78ºF)
Electrical chases:[1] Rooms 3250, 3261	25.6ºC (78ºF)
CRHA Heat Sink Group 3	
HVAC equipment rooms: Rooms 3401, 3402, 3403 and 3404	40ºC (104ºF)
Safety Portions of CRHAVS: Rooms 3406, 3407	40ºC (104ºF)

1. Access corridors, electrical chases, and HVAC chases, although part of the CRHA heat sink, are not monitored because these areas do not contain heat sources and their temperatures are assumed to match the average of the associated group.

Intentionally Blank

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Condenser Offgas

BASES

BACKGROUND	During unit operation, steam from the low-pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, and then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser, and the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.
APPLICABLE SAFETY ANALYSES	The main condenser offgas gross gamma activity rate is an initial condition of the Waste Gas System leak or failure event as discussed in Sections 11.3.7 and 15.0.3.4.7 (Refs. 1 and 2, respectively). The analysis assumes inadvertent operator action with the bypass of the delay charcoal beds leading to a direct release of radioactive noble gases from the Main Condenser Offgas System. The gross gamma activity rate is controlled to ensure that during the event, the calculated offsite doses using the annual average atmospheric dispersion factor will be well within the acceptance criterion of 25 mSv (2.5 rem) TEDE (Ref. 3). The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	To ensure compliance with the assumptions of the Waste Gas System leak or failure event (Refs. 1 and 2), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 100 μCi/second/Mwt after decay of 30 minutes. The LCO is established consistent with this requirement (4500 MWt x 100 μCi/second/MWt = 450 mCi/second).

BASES

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2, 3, and 4 with any main steam line not isolated and the SJAE in operation. In MODES 5 and 6, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72-hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Waste Gas System leak or failure event occurring.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12-hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Action B.1 or B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR, on a 31-day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed, within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31-day Frequency is adequate in view of other instrumentation that continuously monitors the offgas, and is acceptable based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. Section 11.3.7.
2. Section 15.0.3.4.7.
3. NUREG-0800, Branch Technical Position 11-5, Revision 3, March 2007.

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B 3.7 PLANT SYSTEMS

B 3.7.4 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 110% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram.

The Main Turbine Bypass System consists of turbine bypass valves (TBVs) connected to the main steam lines between the main steam isolation valves (MSIVs) and the turbine stop valves. The turbine hydraulic fluid power unit supplies high-pressure fluid to sequentially open the TBVs and can be isolated from supplying high-pressure fluid to the turbine valves while supplying hydraulic fluid to the TBVs. The TBVs are controlled by the pressure regulation function of the Steam Bypass and Pressure Control (SB&PC) System, as discussed in Reference 1. The TBVs are normally closed, and the pressure regulator controls the turbine control valves (TCVs), directing all steam flow to the turbine. The TBVs are opened by redundant signals from the SB&PC System, which uses a triply redundant digital control system, whenever the actual steam pressure exceeds the preset steam pressure by a small margin. This bypass demand opens the TBVs in sequence as necessary to control pressure. Additionally, the TBVs are equipped with fast acting solenoid valves to allow rapid opening of the valves for the generator load rejection with turbine bypass, generator load rejection with a single failure in the turbine bypass system, turbine trip with turbine bypass, and turbine trip with a single failure in the turbine bypass system events (Ref. 2). No credible single failure in the control system results in a minimum demand to all TCVs and TBVs, or in disabling more than 50% of the TBVs. When the TBVs open, the steam flows from the bypass valves to the condenser through connecting piping and pressure reducers.

BASES

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during transient events that could result in increase in reactor pressure (i.e., closure of one TCV, generator load rejection with turbine bypass, generator load rejection with a single failure in the turbine bypass system, turbine trip with turbine bypass, turbine trip with a single failure in the turbine bypass system, closure of one MSIV, and feedwater controller failure – maximum demand). Opening of the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event.

STD COL 16.0-1-A 3.7.4-1

The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Fuel Cladding Integrity Safety Limit (FCISL) is not exceeded.

STD COL 16.0-1-A 3.7.4-1

An OPERABLE Main Turbine Bypass System requires the TBVs to open in response to increasing main steam line pressure or in the fast opening mode, as applicable. This response is within the assumptions of the applicable analyses (Ref. 3).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the FCISL and the cladding 1% plastic strain limit are not violated during transient events such as the generator load rejection with turbine bypass event. As discussed in the Bases for LCO 3.2.2, sufficient margin to these limits exists below 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

STD COL 16.0-1-A 3.7.4-1

If the Main Turbine Bypass System is inoperable (one or more TBVs inoperable), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR limits accordingly. The 2-hour Completion Time is reasonable, based

BASES

ACTIONS (continued)

on the time to complete the Required Action, and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If Required Action A.1 and associated Completion Time cannot be met, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during transient events such as the generator load rejection with turbine bypass event. The 4-hour Completion Time is reasonable, based on operating experience, to reach the required unit condition from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

STD COL 16.0-1-A 3.7.4-2

Cycling each TBV through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is concluded to be acceptable from a reliability standpoint.

SR 3.7.4.2

The Main Turbine Bypass System is required to actuate automatically to perform its designed function. This SR demonstrates that with the required system initiation signals, the TBVs will actuate to their required position. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

SR 3.7.4.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in

BASES

SURVEILLANCE REQUIREMENTS (continued)	Reference 4. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

1. Section 7.7.5.
2. Section 10.4.4.
3. Section 15.2.2.
4. Chapter 15, Table 15.2-1

B 3.7 PLANT SYSTEMS

B 3.7.5 Fuel Pool Water Level and Temperature

BASES

BACKGROUND	The minimum water level in the deep pit area of the reactor building buffer pool and in the fuel building spent fuel storage pool bounds the assumptions of iodine decontamination factors following a fuel handling accident. The water in these pools also provides a large capacity heat sink in the event the Fuel and Auxiliary Pools Cooling System (FAPCS) is unavailable. The minimum water level and assumed initial pool temperature for a postulated loss of FAPCS are found in Reference 5. A general description of the reactor building buffer pool and fuel building spent fuel storage pool design is found in Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in Section 15.4.1 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure the radiological consequences (whole-body dose or its equivalent to any part of the body calculated at the exclusion area and low population zone boundaries) are < 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) and < 0.05 Sv (5.0 rem) TEDE in the control room as required by 10 CFR 52.47(a)(2)(iv) (Ref. 3) and Regulatory Guide 1.183 (Ref. 4) acceptance criteria. A fuel handling accident is assumed to damage all of the fuel rods in two (2) fuel assemblies as discussed in References 2 and 4. The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core which bounds the consequences of dropping an irradiated fuel assembly onto stored fuel bundles. The justification for the bounding analysis used, initial assumptions of the analysis, and consequences of a fuel handling accident inside the reactor building are documented in Reference 2. The water level above the irradiated fuel assemblies provides for absorption of water-soluble fission-product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the reactor building or fuel building atmosphere. This

BASES

APPLICABLE SAFETY ANALYSES (continued)	absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident. In addition to mitigating the effects of a fuel handling accident, the required minimum water level and maximum water temperature in the spent fuel storage pool and buffer pool provide a large capacity heat sink in the event FAPCS is unavailable. For both pools, the water levels and free volumes are sufficient to ensure that following a loss of active cooling without makeup that persists for 72 hours, the water levels in the pools remain above the top of the irradiated fuel assemblies. The minimum water level required for the buffer pool is less than that required for the spent fuel pool, however the bounding value of 10.26 m is utilized for this LCO. The fuel pool water level and temperature satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The water level limit preserves the assumption of the fuel handling accident analysis (Ref. 2) and loss of FAPCS (Ref. 5). The water temperature limit preserves the assumption of loss of FAPCS (Ref. 5).
APPLICABILITY	This LCO applies whenever irradiated fuel assemblies are being moved or stored in the associated fuel storage racks since the potential for a release of fission-products exists.
ACTIONS	<u>A.1</u> When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With either fuel pool level less than required, the movement of irradiated fuel assemblies in the associated storage pool is immediately suspended. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

BASES

ACTIONS (continued)

This action is also appropriate when fuel pool average water temperature is not within limit since adding heat load to a pool with reduced capacity as a heat sink should not be performed.

A.2

If the water level in the spent fuel storage pool or buffer pool is < 10.26 m (33.7 ft) above the top of the irradiated fuel assemblies, or if the average water temperature is > 60°C (140°F), the heat capacity of the pool may be less than that assumed in the event of a loss of FAPCS. In this case, action must be initiated within 1 hour to restore the water level and temperature to within limit. Action must continue until the parameter is restored to within the applicable limit.

The Completion Time of 1 hour ensures prompt action will be taken to compensate for a degraded condition.

Required Actions A.1 and A.2 have been modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Fuel pool cooling requirements are also independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies or to initiate restoration of fuel pool water level and temperature to within limit is not a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies sufficient water is available to mitigate the consequences of a fuel handling accident or a loss of cooling in the spent fuel storage pool or buffer pool. The water level in the spent fuel storage pool and buffer pool must be checked periodically. The 7-day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable and water level changes are controlled by unit procedures.

During refueling operations, the level above the top of the RPV flange is verified every 24 hours in accordance with SR 3.9.6.1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

This SR verifies that the average water temperature in the spent fuel storage pool and buffer pool is low enough to mitigate the consequences of a loss of cooling. The temperature in the spent fuel storage pool and buffer pool must be checked periodically. The 7-day Frequency is acceptable considering the alarms and indications available to alert the operator to abnormal conditions associated with the fuel pool and FAPCS.

REFERENCES

1. Section 9.1.2.
2. Section 15.4.1.
3. 10 CFR 52.47(a)(2)(iv).
4. Regulatory Guide 1.183, July 2000.
5. Section 9.1.3.2.

B 3.7 PLANT SYSTEMS

B 3.7.6 Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions

BASES

BACKGROUND

Selected Control Rod Run-In (SCRRI) function logic is performed when the Rod Control and Information System (RC&IS) performs 2/3 voting on a Selected Control Rod Run-in/Select Rod Insert (SCRRI/SRI) signal from the Diverse Protection System (DPS) (Ref. 1). RC&IS provides for electrical insertion of selected control rods: 1) for mitigation of a loss of feedwater heating event; or 2) for providing needed power reduction after occurrence of a load rejection event or a turbine trip event. The Automated Thermal Limit Monitor (ATLM) provides an additional SCRRI/SRI signal to RC&IS for mitigation of a loss of feedwater heating event.

RC&IS utilizes a dual-redundant architecture of two independent channels for normal monitoring of control rod positions and executing normal control rod movement commands. Under normal conditions, each channel receives separate input signals and both channels perform the same functions. For the Fine Motion Control Rod Drive (FMCRD) emergency insertion functions (scram-follow, FMCRD run-in, and SCRRI), 3-out-of-3 logic is used in the induction motor controller logic with the additional input signal coming from the associated emergency rod insertion panels. An automatic single channel bypass feature (only activated when an emergency insertion function is activated) is also provided to assure high availability for the emergency insertion functions when a single channel failure condition exists.

Failure or malfunction of RC&IS has no impact on the hydraulic scram function of the CRDs. The circuitry for normal insertion and withdrawal of control rods in RC&IS is completely independent of the Reactor Protection System (RPS) circuitry controlling the scram valves. This separation of the RPS scram and RC&IS normal rod control functions prevents failure in the RC&IS circuitry from affecting the scram circuitry.

Select Rod Insert (SRI) function logic in DPS produces the automatic SRI command signal to the scram timing test panel (Ref. 1). Similarly, 2/3 voting is performed by the DPS on the hard-wired turbine trip and load reject signals from the

BASES

BACKGROUND (continued)

turbine control system to produce an automatic SRI command signal to the scram timing test panel. The scram timing test panel provides for hydraulic scram insertion of selected control rods: 1) for mitigation of a loss of feedwater heating event; or 2) for providing needed power reduction after occurrence of a load rejection event or a turbine trip event. ATLM provides an additional SCRRI/SRI signal to RC&IS for mitigation of a loss of feedwater heating event.

DPS utilizes a triplicate redundant system to produce the SRI signal to the scram timing test panel, which on a valid SRI initiation signal causes all the hydraulic control unit (HCU) solenoid return line switches for the control rods selected for SRI to open, resulting in a hydraulic scram of those control rods. The scram timing test panel allows specific HCUs associated with the predetermined SRI control rods to be selected on the scram timing test panel video display unit interface.

Failure or malfunction of DPS or the scram timing test panel has no impact on the hydraulic scram function of the CRDs. The circuitry for emergency electrical insertion and SRI hydraulic insertion of control rods in DPS and the scram timing test panel is completely independent of the RPS circuitry controlling the scram valves. This separation of the RPS scram and the DPS and scram timing test panel control rod functions prevents failure in the DPS and scram timing test panel circuitry from affecting the scram circuitry.

APPLICABLE SAFETY ANALYSES

The SCRRI and SRI functions are assumed to function during transient events that could result in a decrease in core coolant temperature or increase in reactor pressure (i.e., loss of feedwater heating, generator load rejection, and turbine trip). Power reduction from the electrical run-in and hydraulic insertion of selected control rods during these events mitigates the decrease in the MCPR during the event.

STD COL 16.0-1-A 3.7.6-1

The SCRRI and SRI functions satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The SCRRI and SRI functions are required to be OPERABLE to limit decrease in MCPR within acceptable limits during events that cause rapid increase in core reactivity, such that the Fuel Cladding Integrity Safety Limit (FCISL) is not exceeded.

STD COL 16.0-1-A 3.7.6-1

BASES

LCO (continued)

OPERABLE SCRRI and SRI functions actuate in response to a loss of feedwater heating, or a turbine trip or load reject, as applicable. This response is within the assumptions of the applicable analyses (Ref. 2). The specific control rods and insertion limits applicable to the SCRRI and SRI functions are specified in the COLR.

APPLICABILITY

The SCRRI and SRI functions are required to be OPERABLE at ≥ 25% RTP to ensure that the FCISL and the cladding 1% plastic strain limit are not violated during transient events such as the loss of feedwater heating event. As discussed in the Bases for LCO 3.2.2, sufficient margin to these limits exists below 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

STD COL 16.0-1-A 3.7.6-1

If the SCRRI or SRI function is inoperable (including one or more selected control rods inoperable), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the SCRRI and SRI functions to OPERABLE status. The 2-hour Completion Time is reasonable, based on the time to complete the Required Action, and the low probability of an event occurring during this period requiring the SCRRI and SRI functions.

B.1

If Required Action A.1 and associated Completion Time cannot be met, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the SCRRI and SRI functions are not required to protect fuel integrity during transient events such as the loss of feedwater heating event. The 4-hour Completion Time is reasonable, based on operating experience, to reach the required unit condition from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

The control rods assumed to insert, and the final control rod pattern achieved, to accomplish the SCRRI and SRI functions are analyzed for each fuel cycle and are documented in the COLR in accordance with Specification 5.6.3. The Surveillance Requirements of LCO 3.1.3, "Control Rod OPERABILITY," made applicable to the required SCRRI and SRI function control rods are required to establish this LCO is being met.

SR 3.7.6.2

Fine Motion Control Rod Drive (FMCRD) electrical insertion capability for the SCRRI function is verified by ensuring that power is available to the selected FMCRDs. The 7-day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because the FMCRD electrical power availability status is displayed in the control room.

SR 3.7.6.3

The SCRRI function is required to automatically electrically insert selected control rods to perform its designed function. This SR demonstrates that with the required system initiation signals, the SCRRI function will electrically insert the selected control rods to their required position. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

SR 3.7.6.4

The SRI function is required to automatically hydraulically insert selected control rods to perform its designed function. This SR demonstrates that with the required system initiation signals, the SRI function will hydraulically insert the selected control rods to their required position. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the

BASES

SURVEILLANCE REQUIREMENTS (continued)

reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

SR 3.7.6.5

This SR ensures that the FMCRD electrical insertion rate over the required insertion range for each SCRRI control rod required in accordance with the COLR is in compliance with the assumptions of the appropriate safety analysis. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

SR 3.7.6.6

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the required nominal trip setpoint within the "as-left tolerance" to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the Setpoint Control Program. The Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. Sections 7.1 and 7.7.
2. Section 15.2.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 DC Sources - Operating

BASES

BACKGROUND

The DC Sources supply the emergency 250 VDC power to the DC to AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation. Uninterruptible 120 VAC Power supplies all safety-related loads, including the Safety-Related Distributed Control and Information System (Q-DCIS) and the control power for safety-related systems. The DC sources are designed to have sufficient capacity, independence, redundancy, and testability to perform their safety functions when any three of the four divisions are available, assuming a single failure of one of the three required divisions. The DC electrical power system conforms to the recommendations of Regulatory Guide 1.6 (Ref. 1) and IEEE-308 (Ref. 2).

There are two DC Sources for each of the four divisions of the DC Electrical Power Distribution system. Each of the two DC Sources in each division includes a 250 V battery, an associated battery charger (the normal charger), and all the associated control equipment and interconnecting cabling. The battery and battery charger for each DC source are connected to an associated 250 VDC bus. Each division also includes a third battery charger (the standby charger). The standby battery charger may be connected to either of the DC Sources in that division to replace the normal battery charger. The standby battery charger can also be used to charge the battery in either DC source, even if the battery is disconnected from its associated 250 VDC bus.

Each division has two 120 VAC Uninterruptible AC Power inverters, which receive power from an associated rectifier or battery and battery charger. Each rectifier receives 480 VAC normal power from the isolation power center of that division and converts it to 250 VDC. The 480 VAC/250 VDC rectifier and a safety-related 72-hour battery and battery charger of that division supply 250 VDC emergency power through diodes to a common inverter. The output diodes for battery chargers and safety-related rectifiers isolate the output of each required battery from an associated 480 VAC isolation power center bus that is de-energized or has degraded voltage.

BASES

BACKGROUND (continued)

The plant design and circuit layout of the DC systems provide physical separation of the equipment, cabling, and instrumentation essential to plant safety to ensure that a single failure in one division does not cause a failure in a redundant division. There is no sharing between redundant divisions such as batteries, battery chargers, or distribution panels. The 250 V batteries for each division are separately housed in a ventilated room apart from their chargers, distribution buses, and ground detection panels. Equipment for each Division of DC distribution is located in an area separated physically from the other divisions. All the components of 250 VDC sources are housed in Seismic Category I structures.

STD COL 16.0-1-A 3.8.1-5

The batteries are sized so that the batteries in any two of the four divisions have sufficient stored capacity, without recharging, to achieve and maintain safe shutdown conditions for 72 hours following any design basis event. The minimum battery terminal voltage at the end of the discharge period is 210 volts (1.75 volts per cell [Vpc]). The batteries are sized so that the sum of the required loads does not exceed 80% of the battery ampere-hour rating, or warranted capacity at end-of-installed-life with 100% design demand. Batteries are sized for the DC load in accordance with IEEE Standard 485 (Ref. 3) and include margin to compensate for uncertainty in determining the battery state of charge. The battery banks are designed to permit the replacement of individual cells.

Either the normal or the standby battery charger associated with each battery is capable of recharging its battery from the design minimum charge to fully charged condition within 24 hours while supplying the full load of the associated DC source (Ref. 4).

The battery charger is normally in the float-charge mode supplying the connected loads (when those loads are not being supplied via the 480 VAC rectifier) and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

The charger can be placed at a higher voltage than the float mode for battery equalize and following a battery discharge for more rapid recharge. The battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery

BASES

BACKGROUND (continued)

service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. The 72-hour batteries have recharge efficiencies such that once approximately 105% to 110% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 5) and Chapter 15 (Ref. 6) assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC Sources provide emergency 250 VDC power to the DC Electrical Power Distribution System, which supplies power through the inverters to the Uninterruptible 120 VAC Power buses. Uninterruptible 120 VAC Power supports Q-DCIS and the control power for safety-related systems.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining OPERABILITY of the DC Sources needed to support the three divisions of DC and Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution Systems – Operating," so that at least two divisions remain OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite and onsite AC power sources; and

b. A worst-case single failure.

The DC Sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

DC Sources are required to be OPERABLE to support the three Divisions of DC and Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution Systems – Operating." Each required division is required to have two DC Sources, with each DC source consisting of the 250 V battery, the associated battery charger (either the normal or the standby charger), and all the associated control equipment and interconnecting cabling.

BASES

LCO (continued)

Three of the four Divisions of DC Sources are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated Design Basis Accident (DBA). Loss of one of the required Divisions of DC Sources does not prevent the minimum safety function from being performed (Ref. 4).

APPLICABILITY

The DC Sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.2, "DC Sources - Shutdown."

ACTIONS

A.1

Condition A represents one DC Source inoperable on one required division (i.e., one required battery charger, one battery, or one battery and its associated required battery charger inoperable). In this Condition, the remaining OPERABLE battery and battery charger in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power, however, it may not have adequate capacity to support the associated division of the DC Electrical Power Distribution system for the required duration of 72 hours.

With one DC Source inoperable on one required division, the remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, albeit for less than the design basis 72 hours. In this condition, continued power operation should not exceed 72 hours. The 72 hour Completion Time for

BASES

ACTIONS (continued)

the restoration of the inoperable DC source is consistent with the time allowed for one inoperable DC Electrical Power Distribution bus.

B.1

Condition B represents both DC Sources inoperable on one required division. In this Condition, the affected division of the DC Sources may not have adequate capacity to support the associated division of the DC Electrical Power Distribution system following a transient event or DBA concurrent with a loss of offsite and onsite AC power.

With both DC Sources inoperable on one required division, the two remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even if power is lost to the supporting isolation power center buses. However, a single failure could result in the loss of minimum necessary 250 VDC subsystems. Therefore, continued power operation should not exceed 8 hours. The 8 hour Completion Time for the restoration of an inoperable DC source is consistent with the time allowed for an inoperable division of DC Electrical Power Distribution.

C.1 and C.2

When one or more DC Sources on two or more required divisions are inoperable, the remaining DC Sources may not have the capacity to supply power to the divisions of the DC Electrical Power Distribution system for the required duration of 72 hours following a transient event or DBA, concurrent with a loss of offsite and onsite AC power. If the Required Actions for restoration cannot be met within the specified Completion Times, the plant remains vulnerable to a single failure that could impair the capability to reach safe shutdown or to mitigate an accident condition. Therefore, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.22 Vpc or 266.4 V at 25°C (77°F) at the battery terminals). This voltage maintains the battery in a condition that supports maintaining battery life. The 7 day Frequency is consistent with manufacturer recommendations.

STD COL 16.0-1-A 3.8.1-4

SR 3.8.1.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 7), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 500 amps at the minimum established float voltage for 8 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

STD COL 16.0-1-A 3.8.1-1

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available

BASES

SURVEILLANCE REQUIREMENTS (continued)

following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the requirements of SR 3.8.3.1 are met.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24-month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.3

A battery-service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the 250 VDC power system. The discharge rate and test length corresponds to the design duty cycle requirements. The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 7).

SR 3.8.1.4

Operability of a DC Source requires that the output diodes for the associated battery chargers and safety-related rectifiers prevent reverse current flow from the DC Source to the associated isolation power center bus when the isolation power center bus is de-energized or has degraded voltage. This function is required to prevent degraded conditions on the nonsafety-related AC power system from affecting the safety-related DC power system. This SR is not required for battery chargers and safety-related rectifiers that are not connected to the isolation power center bus. This SR is also not required for standby battery chargers that are not connected to the 250 VDC bus. The 24 month Frequency is based on engineering judgment.

SR 3.8.1.5

This SR verifies that each required DC Source can supply the 120 VAC Uninterruptible AC Power inverter for ≥ 4 hours. The 120 VAC Uninterruptible AC Power inverters are normally supplied by the safety-related rectifiers. The circuit between the DC source and the inverter is not tested during either the battery charger capacity test (SR 3.8.1.2) or the

BASES

SURVEILLANCE REQUIREMENTS (continued)

battery service test (SR 3.8.1.3). Failure of the circuit between the DC Source and the 120 VAC Uninterruptible AC Power inverter, which includes the diode that separates the output of the safety-related rectifier from the DC source, could prevent the DC source from performing its required safety function. The 24 month Frequency is based on engineering judgment.

REFERENCES

1. Regulatory Guide 1.6.

2. IEEE Standard 308.

3. IEEE Standard 485.

4. Chapter 8.

5. Chapter 6.

6. Chapter 15.

7. Regulatory Guide 1.32.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 DC Sources - Shutdown

BASES

BACKGROUND	A description of the DC Sources is provided in the Bases for LCO 3.8.1, "DC Sources - Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2) assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC Sources provide emergency 250 VDC power to the DC Electrical Power Distribution System, which supplies power through the inverters to the Uninterruptible 120 VAC Power buses. Uninterruptible 120 VAC Power supports Q-DCIS and the control power for safety-related systems. The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC sources during MODES 5 and 6 ensures that: a. The facility can be maintained in the shutdown or refueling condition for extended periods, b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel. In general, when the unit is shutdown, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the

BASES

APPLICABLE SAFETY ANALYSES (continued)

corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs that are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, has found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC Sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

DC Sources are required to be OPERABLE to support the DC and Uninterruptible AC Electrical Power Distribution Divisions required OPERABLE by LCO 3.8.7, "Distribution Systems - Shutdown." Each required DC source consists of the battery, the associated battery charger (either the normal or the standby charger), and all the associated control equipment and interconnecting cabling.

This LCO ensures the availability of sufficient 250 VDC power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., inadvertent reactor vessel draindown).

BASES

APPLICABILITY

The DC Sources required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel,

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

c. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC source requirements for MODES 1, 2, 3, and 4 are addressed in the Bases for LCO 3.8.1, "DC Sources-Operating."

ACTIONS

A.1

Condition A represents one DC Source inoperable on one required division (i.e., one required battery charger, one battery, or one battery and its associated required battery charger inoperable). In this Condition, the remaining OPERABLE battery and battery charger in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power, however, it may not have adequate capacity to support the associated division of the DC Electrical Power Distribution system for the required duration of 72 hours.

With one DC Source inoperable on one required division, the remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, albeit for less than the design basis 72 hours. The 72 hour Completion Time for the restoration of the inoperable DC source is consistent with the time allowed for one inoperable DC Electrical Power Distribution bus.

BASES

ACTIONS (continued)

B.1, B.2.1, B.2.2, and B.2.3

When two or more DC Sources being used to support the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7 are inoperable, or if the Required Action and associated Completion Time of Condition A are not met, the remaining OPERABLE DC Sources may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and operations with a potential for draining the reactor vessel. By allowing the option to declare systems inoperable when the associated DC sources are inoperable, appropriate restrictions will be implemented in accordance with the ACTIONS of the affected system(s) LCO. In many instances, this would likely involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS and any activities that could potentially result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC sources and to continue this action until restoration is accomplished in order to provide the necessary 250 VDC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires performance of all Surveillances required by SR 3.8.1.1 through SR 3.8.1.5. Therefore, see the corresponding Bases for Specification 3.8.1 for a discussion of each SR.

REFERENCES

1. Chapter 6.

2. Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current and float voltage, individual cell voltage, battery electrolyte temperature, and battery capacity for the DC source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.1, "DC Sources - Operating" and LCO 3.8.2, "DC Sources - Shutdown." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.10 for monitoring various battery parameters.

STD COL 16.0-1-A 3.8.3-3

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.240. This specific gravity corresponds to battery cells that have an open circuit battery voltage of approximately 249.6 V for 120 cell battery (i.e., cell voltage of 2.07 to 2.09 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.07 to 2.09] Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. However, optimal long-term performance is obtained by maintaining a float voltage 2.22 to 2.24] Vpc at 25°C (77°F). This provides adequate over-potential, which limits the formation of lead sulfate and self-discharge. The nominal float voltage of 2.23 Vpc at 25°C (77°F) corresponds to a total float voltage output of 267.6] V for a 120 cell battery as discussed in Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3) assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC Sources provide the emergency 250 VDC power to the DC Electrical Power Distribution System, which supplies power through the inverters to the Uninterruptible 120 VAC Power buses. Uninterruptible 120 VAC Power supports Q-DCIS and the control power for safety-related systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as described in the Bases for LCO 3.8.1, "DC Sources - Operating" and LCO 3.8.2, "DC Sources - Shutdown."

Since battery parameters support the operation of the DC sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC sources to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC source function even with limits not met. Additional preventative maintenance, testing, and monitoring are performed in accordance with Specification 5.5.10, Battery Monitoring and Maintenance Program.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC sources. Therefore, battery parameter limits are only required when the DC sources are required to be OPERABLE. Refer to Applicability discussion in Bases for LCO 3.8.1 and LCO 3.8.2.

ACTIONS

A.1, A.2, and A.3

STD COL 16.0-1-A 3.8.3-3

With one or more cells in one or more batteries in one required division < 2.09] V, the battery cell is degraded. Within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.1.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.3.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.09] V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.1.1 or SR 3.8.3.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed, the appropriate Condition(s), depending

BASES

ACTIONS (continued)

on the cause of the failures, is entered. If SR 3.8.3.1 is failed, then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1, B.2, C.1 and C.2

STD COL 16.0-1-A 3.8.3-1

One or two batteries on one required division with float current > 30 amps indicates that a partial discharge of the battery has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within the allowed Completion Time (Required Actions B.2 and C.2). The battery must therefore be declared inoperable. LCO 3.8.1 addresses battery and charger inoperability.

STD COL 16.0-1-A 3.8.3-3

If the float voltage is found not to be satisfactory and there are one or more battery cells with float voltage less than 2.09] V, the associated "OR" statement in Condition G is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.09] V, there is good assurance that, within 24 hours, the battery will be restored to its fully charged condition from any discharge that might have occurred due to a temporary loss of the battery charger. As described in Reference 1, either the normal or the standby battery charger associated with each battery is capable of recharging its battery from the design minimum charge to fully charged condition within 24 hours while supplying the full load of the associated DC source.

BASES

ACTIONS (continued)

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus, there is good assurance of fully recharging the battery within the allowed Completion Time.

STD COL 16.0-1-A 3.8.3-1

If Condition B is entered due to one battery on one required division with float current > 30 amps, then 24 hours is allowed for recharging the battery (Required Action B.2). As discussed previously, 24 hours should be adequate to restore the battery to its fully charged condition from any discharge that might have occurred due to a temporary loss of the battery charger. However, if Condition C is entered due to two batteries on one required division with float current > 30 amps, then only 8 hours is allowed to recharge at least one of the batteries (Required Action C.2). 8 hours should be adequate to recharge a battery following a short duration discharge. The more conservative Completion Time of 8 hours is based on engineering judgment considering the increased risk that the affected division of the DC and Uninterruptible AC Electrical Power Distribution System may not have adequate capacity to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power.

STD COL 16.0-1-A 3.8.3-3

If the condition is due to one or more cells in a low voltage condition but still greater than 2.09 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 24 hours (Required Action B.2 for one affected battery) or 8 hours (Required Action C.2 for two affected batteries) is a reasonable time prior to declaring the battery inoperable.

Since Required Actions B.1 and C.1 only specify "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.1.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

D.1, D.2, and D.3

With one or two batteries on one required division with one or more cells with electrolyte level above the top of the plates, but below the minimum established design limits, the

BASES

ACTIONS (continued)

batteries still retain sufficient capacity to perform the intended function. Therefore, the affected batteries are not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days, the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates, there is a potential for dryout and plate degradation. Required Actions D.1 and D.2 address this potential (as well as provisions in Specification 5.5.10, Battery Monitoring and Maintenance Program). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates.

Within 8 hours, level is required to be restored to above the top of the plates. The Required Action D.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.10.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450 (Ref. 4). They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing, the battery may have to be declared inoperable and the affected cell(s) replaced.

E.1

With one or two batteries on one required division with battery pilot cell electrolyte temperature less than the minimum established design limit, 12 hours is allowed to restore the temperature to within limits. A low temperature results in reduced battery capacity. Since the battery is sized with margin, sufficient capacity exists to perform the intended function and the temporary degradation in battery capacity does not require the battery to be considered inoperable solely as a result of pilot cell electrolyte temperature not met.

F.1

With one or more required batteries in redundant required divisions with battery parameters not within limits, there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant divisions are involved. With redundant divisions involved, this potential could result in a total loss of function on

BASES

ACTIONS (continued)

multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on one required division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one required division within 2 hours.

G.1

When any battery parameter is outside the allowances of the Required Actions for Condition A, B, C, D, E, or F sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one battery with one or more battery cells with float voltage less than 2.09 V and float current > 30 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

STD COL 16.0-1-A 3.8.3-3
STD COL 16.0-1-A 3.8.3-1

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. The 30 amp value is based on returning the battery to 95% charge and assumes a 5% design margin for the battery.] Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 4). The 7-day Frequency is consistent with IEEE-450 (Ref. 4).

STD COL 16.0-1-A 3.8.3-1

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.1.1. When this float voltage is not maintained, the Required Actions of LCO 3.8.1 are being taken. Furthermore, the float current limit of 30 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

STD COL 16.0-1-A 3.8.3-1

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2 and SR 3.8.3.5

STD COL 16.0-1-A 3.8.3-3

Optimal long-term battery performance is obtained by maintaining a float voltage within established design limits provided by the battery manufacturer, which corresponds to nominally 267.6] V at the battery terminals, or 2.23] Vpc at 25°C (77°F). This provides adequate overpotential, which limits the formation of lead sulfate and self-discharge, which could eventually render the battery inoperable. Float voltages below 2.13] Vpc at 25°C (77°F) but greater than 2.09] Vpc, are addressed in Specification 5.5.10. SR 3.8.3.2 and SR 3.8.3.5 require verification that the cell float voltages are equal to or greater than the short-term absolute minimum voltage of 2.09] Vpc. The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450 (Ref. 4). A pilot cell is selected in the series string to reflect the general condition of cells in the battery. The cell selected is the lowest cell voltage in the series string following each quarterly surveillance.

SR 3.8.3.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 4).

SR 3.8.3.4

STD COL 16.0-1-A 3.8.3-1

This Surveillance verifies that the required battery pilot call electrolyte temperature is greater than or equal to the design minimum temperature (i.e., 16°C (60°F)) to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 4).

SR 3.8.3.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as-found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 4) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. The battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

STD COL 16.0-1-A 3.8.3-4

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 4), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 90% of the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 4).

REFERENCES

1. Chapter 8.
2. Chapter 6.
3. Chapter 15.
4. IEEE Standard 450.
5. IEEE Standard 485.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 Inverters - Operating

BASES

BACKGROUND

The DC-to-AC inverters are the preferred source of power for the Uninterruptible 120 VAC Power during all modes of operation because of the stability and reliability they achieve in being powered from the associated safety-related DC sources. Uninterruptible 120 VAC Power supplies all safety-related loads, including the Safety-Related Distributed Control and Information System (Q-DCIS) and the control power for safety-related systems.

Each of the four divisions of DC and Uninterruptible AC Electrical Power includes two separate DC-to-AC inverters, one associated with each of the DC Sources. Each inverter receives DC power from either the associated safety-related rectifier or the associated 250 VDC bus that is supported by the battery and charger. The output diodes for the battery chargers and safety-related rectifiers isolate the output of each required battery from an associated 480 VAC isolation power center bus that is de-energized or has degraded voltage.

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in Chapter 6, "Engineered Safety Features," (Ref. 1) and Chapter 15, "Safety Analyses," (Ref. 2) assume Engineered Safety Feature (ESF) systems are OPERABLE. The 250 VDC power system provides normal and emergency 250 VDC power to DC-to-AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation.

Uninterruptible 120 VAC Power supports Q-DCIS and the control power for safety-related systems.

The OPERABILITY of the 250 VDC power is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining OPERABILITY of the DC-to-AC inverters needed to support the three divisions of Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution

BASES

APPLICABLE SAFETY ANALYSES (continued)

Systems – Operating," so that at least two divisions remain OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power and all onsite AC electrical power; and

b. A worst-case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Inverters are required to be OPERABLE to support the three Divisions of DC and Uninterruptible AC Electrical Power Distribution required by LCO 3.8.6, "Distribution Systems – Operating." Each required division is required to have two inverters, one associated with each DC source. An OPERABLE inverter must be connected to the associated Uninterruptible 120 VAC Power bus and maintaining output voltage and frequency within design tolerances.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.5, "Inverters – Shutdown."

ACTIONS

A.1

Condition A represents one inverter inoperable on one required division. In this Condition, the affected division with one inverter remaining OPERABLE can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power, however, it may not have adequate capacity to support

BASES

ACTIONS (continued)

the associated division of the Uninterruptible AC Electrical Power Distribution system for the required duration of 72 hours.

With one inverter inoperable on one required division, the Uninterruptible AC Electrical Power Distribution buses in the remaining required divisions are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition even with an additional single failure, albeit for less than the design basis 72 hours. In this condition, continued power operation should not exceed 72 hours.

The 72-hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail.

<u>B.1</u>

Condition B represents two inverters inoperable on one required division. In this Condition, power to the associated Uninterruptible AC Electrical Power Distribution buses cannot be assured following a transient event or DBA concurrent with a loss of offsite and onsite AC power. With both inverters inoperable on one required division, the Uninterruptible AC Electrical Power Distribution buses in the two remaining required divisions are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition.

The 8-hour Completion Time for the restoration of an inoperable inverter on one Uninterruptible AC Electrical Power Distribution bus is consistent with the time allowed for an inoperable division of Uninterruptible AC Electrical Power Distribution buses.

<u>C.1 and C.2</u>

When one or both inverters on two or more required divisions are inoperable, the remaining inverters may not have the capacity to support a safe shutdown and to mitigate an accident condition, especially if power is lost to the supporting isolation power center buses. If the Required

BASES

ACTIONS (continued)

Actions for restoration of a required inverter cannot be met within the specified Completion Time, the plant remains vulnerable to a single failure that could impair the capability to reach safe shutdown or to mitigate an accident condition. Therefore, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and Uninterruptible AC Electrical Power Distribution buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for Q-DCIS and the control power for safety-related systems connected to the Uninterruptible AC Buses. The 7-day Frequency takes into account the availability of redundant inverters and other indications available in the control room that will alert the operator to inverter malfunctions.

REFERENCES

1. Chapter 6.
2. Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for Specification 3.8.4, "Inverters - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in Chapter 6, "Engineered Safety Features," (Ref. 1) and Chapter 15, "Safety Analyses," (Ref. 2) assume Engineered Safety Feature (ESF) systems are OPERABLE. The 250 VDC power system provides normal and emergency 250 VDC power to DC-to-AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation. Uninterruptible 120 VAC Power supports Safety-Related Distributed Control and Information System (Q-DCIS) and the control power for safety-related systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the inverters during MODES 5 and 6 ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability are available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6

BASES

APPLICABLE SAFETY ANALYSES (continued)	because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems. The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs, which are analyzed for operating MODES, are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, has found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications. The inverters are considered part of the Distribution System, and as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Inverters are required to be OPERABLE to support the Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.7, "Distribution Systems – Shutdown." This LCO ensures the availability of sufficient inverters to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., inadvertent reactor vessel draindown). An OPERABLE inverter must be connected to the associated Uninterruptible 120 VAC Power bus and maintaining output voltage and frequency within design tolerances.

BASES

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4, "Inverters - Operating."

ACTIONS

A.1

In this Condition, the affected division with one inverter remaining OPERABLE can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power, however, it may not have adequate capacity to support the associated division of the Uninterruptible AC Electrical Power Distribution system for the required duration of 72 hours. With one inverter inoperable on one required division, the Uninterruptible AC Electrical Power Distribution buses in the remaining required divisions are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition even with an additional single failure, albeit for less than the design basis 72 hours.

The 72 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability.

B.1, B.2.1, B.2.2, and B.2.3

If two or more required inverters are inoperable, or if the Required Actions for restoration cannot be met within the specified Completion Times, the remaining OPERABLE inverters

BASES

ACTIONS (continued)

may be capable of supporting sufficient required feature(s) to allow continuation of CORE ALTERATIONS and operations with a potential for draining the reactor vessel. By allowing the option to declare required feature(s) associated with an inoperable inverter inoperable, appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS and any activities that could potentially result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the plant safety-related systems. The Completion Time of Immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit's safety-related systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and Uninterruptible AC Electrical Power Distribution buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the Q-DCIS and the control power for safety-related systems connected to the Uninterruptible AC Electrical Power Distribution buses. The 7-day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that will alert the operator to inverter malfunctions.

REFERENCES

1. Chapter 6.
2. Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Distribution Systems - Operating

BASES

BACKGROUND

The DC Electrical Power Distribution system provides the normal and emergency power to the DC-to-AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation. Uninterruptible 120 VAC Power supplies all safety-related loads, including the Safety-Related Distributed Control and Information System (Q-DCIS) and the control power for safety-related systems. The DC and Uninterruptible 120 VAC Electrical Power Distribution system is designed to have sufficient capacity, independence, redundancy, and testability to perform its safety functions, assuming a single failure, when any three of the four divisions are available.

Each of the four divisions of DC and Uninterruptible AC Electrical Power distribution includes two 250 VDC Electrical Power Distribution buses and two Uninterruptible 120 VAC Power buses.

Each of the two 250 VDC Electrical Power Distribution buses in each division is powered from an associated DC source consisting of a battery and a battery charger that is powered from an isolation power center bus. The output of each 250 VDC Electrical Power Distribution bus is the safety-related and uninterruptible source of power to an associated DC-to-AC inverter. A safety-related rectifier powered from the isolation power center bus provides the normal source of power to the inverter. If there is loss of power to the isolation power center bus or the safety-related rectifier fails, the 250 VDC Electrical Power Distribution bus will transparently continue to supply power to the Inverter. The Bases for Specification 3.8.1, "DC Sources -Operating," provides a more detailed description of the DC Sources and the 250 VDC Electrical Power Distribution buses.

The two inverters in each safety-related division are configured for parallel redundant operation to allow load sharing and the equal discharge of the division's safety-related batteries to the Uninterruptible 120 VAC Electrical Power buses in each division. The inverter, which receives its power from a 250 VDC Electrical Power Distribution bus as described above, is the safety-related, uninterruptible source of power to an associated

BASES

BACKGROUND (continued)	Uninterruptible 120 VAC Electrical Power bus. The Bases for Specification 3.8.4, "Inverters -Operating," provides a more detailed description of the inverters and the Uninterruptible 120 VAC Electrical Power buses. The DC and Uninterruptible AC Electrical Power Distribution buses are listed in Table B 3.8.6-1. Two divisions (1 and 2) of safety-related power supply the reactor protection system (RPS) scram pilot valve solenoids and the same two divisions supply power to the main steam isolation valve (MSIV) solenoids.
APPLICABLE SAFETY ANALYSES	The initial conditions of design basis transient and accident analyses in Chapter 6, "Engineered Safety Features," (Ref. 1) and Chapter 15, "Safety Analyses," (Ref. 2) assume Engineered Safety Feature (ESF) systems are OPERABLE. The DC Electrical Power Distribution system provides the normal and emergency power to the DC-to-AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation. Uninterruptible 120 VAC Power supplies all safety-related loads, including the Q-DCIS and the control power for safety-related systems. The OPERABILITY of the DC and Uninterruptible AC Electrical Power Distribution is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining OPERABILITY of three divisions of Uninterruptible AC Electrical Power so that at least two divisions remain OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite AC electrical power and all onsite AC electrical power; and b. A worst-case single failure. The DC and Uninterruptible AC Electrical Power Distribution system satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution buses listed in Table B 3.8.6-1 are required to be OPERABLE to ensure the availability of the required power to shut down the reactor

BASES

LCO (continued)

and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated Design Basis Accident (DBA).

Maintaining any three of the four divisions of DC and Uninterruptible AC Electrical Power Distribution buses OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the four divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution does not prevent safe shutdown of the reactor.

OPERABLE 250 VDC Electrical Power Distribution buses must be energized to their proper voltage from either the associated battery or charger. OPERABLE Uninterruptible 120 VAC Electrical Power buses must be energized to their proper voltage and frequency.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.7, "Distribution Systems –Shutdown."

ACTIONS

A.1

Condition A represents one 250 VDC Electrical Power Distribution bus in one required division inoperable. In this Condition, the remaining OPERABLE 250 VDC Electrical Power Distribution bus in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power.

BASES

ACTIONS (continued)

With one 250 VDC Electrical Power Distribution bus inoperable in one required division, the remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, and even if power is lost to the supporting isolation power center buses, albeit for less than the design basis 72 hours. The 72-hour Completion Time for restoration is based upon engineering judgment.

B.1

Condition B represents both 250 VDC Electrical Power Distribution buses in one required division inoperable. In this Condition, power to the associated Uninterruptible AC Electrical Power Distribution buses cannot be assured during an event that includes loss of power to the associated isolation power center bus, which supplies power to the battery chargers and the safety-related rectifiers.

With both 250 VDC Electrical Power Distribution buses inoperable in one required division, the two remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even if power is lost to the supporting isolation power center buses. Since a subsequent worst-case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 8 hours. The 8-hour Completion Time for restoration is based upon engineering judgment.

C.1

Condition C represents one Uninterruptible 120 VAC Electrical Power bus inoperable in one required division. In this Condition, the remaining OPERABLE Uninterruptible 120 VAC Electrical Power Distribution bus in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power. The remaining divisions with OPERABLE Uninterruptible 120 VAC Electrical Power buses still have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, and even if power is lost to the supporting isolation power center buses, albeit for less than the design basis 72 hours. The 72-hour Completion Time is based on engineering judgment.

BASES

ACTIONS (continued)

D.1

Condition D represents both Uninterruptible 120 VAC Electrical Power buses inoperable in one required division. In this condition, the voltage and frequency of the power being supplied to the safety-related loads for that division, including the Q-DCIS and the control power for safety-related systems, cannot be maintained within required limits even when the associated isolation power center bus remains energized. The two remaining divisions with OPERABLE 120 VAC Electrical Power buses still have the capacity to support a safe shutdown and to mitigate an accident condition even if power is lost to the supporting isolation power center buses. Since a subsequent single failure could, however, result in the loss of minimum necessary Uninterruptible 120 VAC Electrical Power buses, continued power operation should not exceed 8 hours. The 8-hour Completion Time is based on engineering judgment.

E.1 and E.2

Condition E represents inoperability of one Uninterruptible AC Electrical Power Distribution bus on one required division concurrent with inoperability of the DC Electrical Power Distribution bus associated with the redundant AC Electrical Power Distribution bus on the same division. With the inoperability of the DC Electrical Power Distribution bus, power to the associated Uninterruptible AC Electrical Power Distribution bus cannot be assured during an event that includes loss of power to the associated isolation power center bus. Therefore, in this condition, the required division is not able to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power. The two remaining required divisions of DC and Uninterruptible AC Electrical Power have the capacity to support a safe shutdown and to mitigate an accident condition even if power is lost to the supporting isolation power center buses. Since a subsequent worst-case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 8 hours. The 8-hour Completion Time for restoration is based upon engineering judgment.

BASES

ACTIONS (continued)

F.1 and F.2

Condition F represents two or more required divisions with one or more DC or Uninterruptible AC Electrical Power Distribution buses (i.e., any combination) inoperable, or the Required Action and associated Completion Time of Condition A, B, C, D, or E not met. When one or more DC or Uninterruptible AC Electrical Power Distribution buses (i.e., any combination) on two or more required divisions are inoperable, the remaining Electrical Power Distribution buses may not have the capacity to support a safe shutdown and to mitigate an accident condition. If the Required Actions for restoration of a required DC or Uninterruptible AC Electrical Power Distribution bus cannot be met within the specified Completion Time, the plant remains vulnerable to a single failure that could impair the capability to reach safe shutdown or to mitigate an accident condition. Therefore, the unit must be placed in a MODE that minimizes risk. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This Surveillance verifies that the DC and Uninterruptible AC Electrical Power Distribution buses are functioning properly, with the correct circuit breaker alignment and that the buses energized from normal power. The correct breaker alignment ensures the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required power is readily available for all safety-related loads, including the Q-DCIS and the control power for safety-related systems. The 7-day Frequency takes into account the redundant capability of the DC and Uninterruptible AC Electrical Power Distribution buses, and other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. Chapter 6.

2. Chapter 15.

BASES

Table B 3.8.6-1 (page 1 of 1)
DC and Uninterruptible AC Electrical Power Distribution

TYPE	VOLTAGE	DIVISION 1	DIVISION 2	DIVISION 3	DIVISION 4
Electrical Power Distribution Buses	250 VDC	Bus 11 Bus 12	Bus 21 Bus 22	Bus 31 Bus 32	Bus 41 Bus 42
Uninterruptible Electrical Power Buses	120 VAC	Bus 11 Bus 12	Bus 21 Bus 22	Bus 31 Bus 32	Bus 41 Bus 42

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of DC and Uninterruptible AC Electrical Power Distribution is provided in the Bases for LCO 3.8.6, "Distribution System - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in Chapter 6, "Engineered Safety Features," (Ref. 1) and Chapter 15, "Safety Analyses," (Ref. 2) assume Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power to DC-to-AC inverters, which are used to provide Uninterruptible 120 VAC Power during all modes of operation. Uninterruptible 120 VAC Power supports Safety-Related Distributed Control and Information System (Q-DCIS) and the control power for safety-related systems.

The OPERABILITY of DC and Uninterruptible AC Electrical Power Distribution is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of DC and Uninterruptible AC Electrical Power Distribution during MODES 5 and 6 ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods,

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case

BASES

APPLICABLE SAFETY ANALYSES (continued)

bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs, which are analyzed for operating MODES, are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, has found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

DC and Uninterruptible AC Electrical Power Distribution satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

DC and Uninterruptible AC Electrical Power Distribution buses are required to be OPERABLE to support equipment required to respond to any anticipated operational occurrence (AOO) or DBA. Various LCOs establish requirements for a minimum number of divisions, subsystems, or trains of equipment needed to respond to an AOO or DBA depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications' required divisions, subsystems, or trains - both specifically addressed by their own LCOs and implicitly required by the definition of OPERABILITY.

BASES

LCO (continued)

Maintaining these portions of DC and Uninterruptible AC Electrical Power Distribution energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., inadvertent reactor vessel draindown).

APPLICABILITY

The DC and Uninterruptible AC Electrical Power Distribution is required to be OPERABLE in MODES 5 and 6 to provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

DC and Uninterruptible AC electrical power distribution subsystem requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.6, "Distribution Systems - Operating."

ACTIONS

A.1

Condition A represents one 250 VDC Electrical Power Distribution bus in one required division inoperable. In this Condition, the remaining OPERABLE 250 VDC Electrical Power Distribution bus in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power.

With one 250 VDC Electrical Power Distribution bus inoperable in one required division, the remaining required divisions of DC Electrical Power buses have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, and even if power is lost to the supporting isolation power center

BASES

ACTIONS (continued)

buses, albeit for less than the design basis 72 hours. The 72 hour Completion Time for restoration is based upon engineering judgment.

B.1

Condition B represents one Uninterruptible 120 VAC Electrical Power Distribution bus inoperable in one required division. In this Condition, the remaining OPERABLE Uninterruptible 120 VAC Electrical Power Distribution bus in the associated division can continue to support the immediate safety-related function following a transient event or DBA concurrent with a loss of offsite and onsite AC power. The remaining divisions with OPERABLE Uninterruptible 120 VAC Electrical Power buses still have the capacity to support a safe shutdown and to mitigate an accident condition even with an additional single failure, and even if power is lost to the supporting isolation power center buses. The 72 hour Completion Time is based on engineering judgment.

C.1, C.2.1, C.2.2 and C.2.3

If two or more required 250 VDC Electrical Power Distribution buses are inoperable, or two or more required Uninterruptible 120 VAC Electrical Power Distribution buses are inoperable, or one 120 VAC Electrical Power Distribution bus on one required division is inoperable concurrent with the 250 VDC Electrical Power Distribution bus associated with the redundant AC Electrical Power Distribution bus on the same division being inoperable, or if the Required Actions for restoration cannot be met within the specified Completion Times, the remaining OPERABLE electrical power distribution Division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS and any activities that could potentially result in inadvertent draining of the reactor vessel).

BASES

ACTIONS (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit's safety-related systems.

The Completion Time of Immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit's safety-related systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the DC and Uninterruptible AC Electrical Power Distribution systems are functioning properly, with the required buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7-day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. Chapter 6.
2. Chapter 15.

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B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce plant procedures in preventing the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the full insertion of control rods, the position of the refueling machine, and the loading of the refueling machine fuel grapple or auxiliary hoist. With the reactor mode switch in the refueling position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel generates a control rod withdrawal block signal in the Rod Control & Information System to prevent withdrawing a control rod.

The refueling interlocks prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel-loaded refueling equipment is over the core (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the safety analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

Refueling Equipment Interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To prevent criticality during refueling, the refueling interlocks associated with the reactor mode switch in Refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling machine position, and the refueling machine fuel grapple hoist fuel-loaded (or auxiliary hoist fuel-loaded, if being used) inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 6, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 6. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks when the reactor mode switch is in the Refuel position.

When the reactor mode switch is in the Shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawal cannot occur simultaneously with in-vessel fuel movement. In

BASES

APPLICABILITY (continued)

MODES 1, 2, 3, 4, and 5, the reactor pressure vessel (RPV) head is on and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these conditions.

ACTIONS

A.1, A.2.1, and A.2.2

With one or more of the required refueling equipment interlocks inoperable, the plant must be placed in a condition in which the LCO does not apply. Therefore, Required Action A.1 requires that in-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

Alternatively, Required Actions A.2.1 and A.2.2 require a control rod withdrawal block to be inserted, and all control rods to be subsequently verified to be fully inserted. Required Action A.2.1 ensures no control rods can be withdrawn, because a block to control rod withdrawal is in place. The withdrawal block utilized must ensure that if rod withdrawal is requested, the rod will not respond (i.e., it will remain inserted). Required Action A.2.2 is performed after placing the rod withdrawal block in effect, and provides a verification that all control rods are fully inserted. This verification that all control rods are fully inserted is in addition to the periodic verifications required by SR 3.9.3.1.

Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure unacceptable operations are blocked (e.g., loading fuel into a cell with the control rod withdrawn).

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps such that the entire channel is tested.

BASES

SURVEILLANCE REQUIREMENTS (continued)	The 7-day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to plant operations personnel.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. Section 7.7.2. 3. Section 15.3.7.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refueling Position One-Rod/Rod-Pair-Out Interlock

BASES

BACKGROUND

The refuel position one-rod/rod-pair-out interlock restricts the movement of control rods to reinforce plant procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod or control rod pair with the same hydraulic control unit (HCU) is permitted to be withdrawn. To enable the one-rod/rod-pair-out interlock, the Rod Control and Information System (RC&IS) GANG/SINGLE selection switch may be in "SINGLE" or "GANG" mode. Otherwise, it is not possible to withdraw the one or two rods associated with the same HCU, respectively, while in the refueling mode.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod/rod-pair-out interlock prevents the selection of a second control rod for movement when any other control rod or control rod pair is not fully inserted (Ref. 2). It is a logic circuit, which has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the RC&IS).

APPLICABLE SAFETY ANALYSES

The refuel position one-rod/rod-pair-out interlock is explicitly assumed in the safety analysis of the control rod withdrawal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

The refuel position one-rod/rod-pair-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN") prevent criticality by preventing withdrawal of more than one control rod or control rod pair. With one control rod or

BASES

APPLICABLE SAFETY ANALYSES (continued)	control rod pair withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion. The refuel position one-rod/rod-pair-out Interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	To prevent criticality during MODE 6, the refuel position one-rod/rod-pair-out interlock ensures no more than one control rod or one control rod pair with the same HCU may be withdrawn. The refuel position one-rod/rod-pair-out interlock is required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of the interlock.
APPLICABILITY	In MODE 6, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod/rod-pair-out interlock provides protection against prompt reactivity excursions. In MODES 1, 2, 3, 4 and 5, the refuel position one-rod/rod-pair-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (RPS) (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," and LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation") and the control rods (LCO 3.1.3, "Control Rod OPERABILITY") provide mitigation of potential reactivity excursions. In MODES 3, 4 and 5, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.
ACTIONS	<u>A.1 and A.2</u> With the refuel position one-rod/rod-pair-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod or control rod pair from being withdrawn. This condition may lead to criticality. Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more

BASES

ACTIONS (continued)	fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refuel position one-rod/rod-pair-out interlock requires the reactor mode switch to be in refuel. During control rod withdrawal in MODE 6, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refuel position one-rod/rod-pair-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Frequency of 12 hours is sufficient, in view of other administrative controls utilized during refueling operations, to ensure safe operation.

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod/rod-pair-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps such that the entire channel is tested. The 7-day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator of control rods not fully inserted.

To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is only required to be performed within 1 hour after any control rod is withdrawn.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. Section 7.7.2.
3. Section 15.3.7.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND	Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive (CRD) System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation"). GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions. When the Rod Control and Information System (RC&IS) GANG/SINGLE selection status is in the SINGLE mode, the refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. However, when the RC&IS GANG/SINGLE selection status is in the GANG mode with the individual hydraulic control unit (HCU) scram test mode active, the refueling interlocks allow the one or two control rods that are associated with the same HCU to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod or control rod pair withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN"), the startup range neutron monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation" and LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation"), and the control rod block instrumentation (LCO 3.3.2.1).

BASES

APPLICABLE SAFETY ANALYSES (continued)	The safety analysis of the control rod removal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. Additionally, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality. Control Rod Position satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	All control rods must be fully inserted during applicable refueling conditions to prevent an inadvertent criticality during refueling.
APPLICABILITY	During MODE 6, loading fuel into a core cell with the control rod withdrawn may result in inadvertent criticality. Therefore, the control rod must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn. In MODES 1, 2, 3, 4, and 5, the reactor pressure vessel (RPV) head is on and no fuel loading activities are possible. Therefore, this specification is not applicable in these MODES.
ACTIONS	<u>A.1</u> With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude the completion of movement of a component to a safe condition.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.3.1</u> During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)	The 12-hour Frequency considers the procedural controls on control rod movement during refueling as well as the redundant functions of the refueling interlocks.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. Section 15.3.7.

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B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND	The full-in position indication channel for each control rod provides information necessary to the refueling interlocks. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") use the full-in position indication channels to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position indication channel signal for any control rod prevents the refueling platform from being moved over the core if fuel is loaded in the hoist, thereby preventing fuel loading. Also, this condition prevents the withdrawal of any other control rod. GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SHUTDOWN MARGIN (LCO 3.1.1), the startup range neutron monitor (SRNM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation" and LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The safety analysis for the control rod withdrawal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod or control rod pair withdrawn, and that no more than one control rod or control rod pair can be withdrawn at a time. Control Rod Position Indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Control rod full-in position indication channels must be OPERABLE to provide the required inputs to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling equipment interlock all-rods-in logic (LCO 3.9.1), and correct position indication to the refuel position one-rod/rod-pair-out interlock logic (LCO 3.9.2).

APPLICABILITY

During MODE 6, the control rods must have OPERABLE full-in position indication to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3, 4, and 5, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1), ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A Note has been provided to modify the ACTIONS related to control rod position indication channels. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for control rods with inoperable position indication channels provide appropriate compensatory measures. As such, a Note has been provided which allows separate Condition entry for each control rod with inoperable position indication channels.

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more required full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in

BASES

ACTIONS (continued)

core cells containing one or more fuel assemblies are fully inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude completion of the movement of a component to a safe condition.

Alternatively, actions may be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicator(s) and disarm the drive(s) to ensure that the control rod is not withdrawn. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod full inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the latched full-in and full-in position reed switches). Another option is to bypass Resolver A (which is the current position probe) and use Resolver B instead. If the readings of the two resolvers do not agree, the operator can initiate bypass of one resolver and use the remaining resolver.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod/rod-pair-out interlock and other refueling interlocks which require an all-rods-in permissive. The interlocks are activated when the full-in position indication for any control rod is not present since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. Note that failure to indicate full-in when the control rod is not withdrawn results in conservative actuation of the one-rod/rod-pair-out interlock, and therefore, is not explicitly required to be verified by this SR. The full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator of control rods not fully inserted.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. Section 15.3.7.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY - Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System (RPS), the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

The CRD System also includes the Fine Motion Control Rod Drives (FMCRDs) and the CRD System instrumentation with which the Rod Control and Information System (RC&IS) directly interfaces. The FMCRDs can be inserted either hydraulically or electrically. In response to a scram signal, the FMCRD is inserted hydraulically via the stored energy in the scram accumulators. A redundant signal is also given to insert the FMCRD electrically via its motor drive. This diversity provides a high degree of assurance of rod insertion on demand.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock"), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the startup range neutron monitor (SRNM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation" and LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod removal error during refueling (Ref. 2) evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion

BASES

APPLICABLE SAFETY ANALYSES (continued)

during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides backup protection should a prompt reactivity excursion occur.

Control Rod OPERABILITY - Refueling satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

STD COL 16.0-1-A 3.9.5-1

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is ≥ 12.75 MPaG (1849 psig) and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function.

APPLICABILITY

During MODE 6, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3, 4, 5, and 6, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

A.1

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rods. Inserting the control rod ensures that the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod is fully inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 6, the OPERABILITY of control rods is primarily required to ensure that a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit safety analysis exists

BASES

SURVEILLANCE REQUIREMENTS (continued)
STD COL 16.0-1-A 3.9.5-1

for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated scram accumulator pressure is ≥ 12.75 MPaG (1849 psig).

The 7-day Frequency considers equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights, which indicate low accumulator charge pressures.

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.1.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. Section 15.3.7.

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B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND	The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 7.01 m (23.0 ft) above the top of the RPV flange. During refueling, this maintains a sufficient water level above the RPV to retain iodine fission product activity in the water in the event of a fuel handling accident (Ref. 1). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) at the exclusion area boundary and < 0.05 Sv (5.0 rem) TEDE in the control room as required by 10 CFR 52.47(a)(2)(iv) (Ref. 2) and Regulatory Guide 1.183 (Ref. 3) acceptance criteria.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, which bounds movement of new fuel assemblies and handling of control rods, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident (Ref. 1). A minimum water level of 7.01 m (23.0 ft) allows a decontamination factor of 200 (Ref. 3) to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 8% of the total fuel rod iodine inventory (Refs. 1 and 2). A fuel handling accident is assumed to damage all of the fuel rods in two fuel assemblies as discussed in Reference 1. Analysis of the fuel handling accident inside the reactor building is described in Reference 1. With a minimum water level of 7.01 m (23.0 ft) and a minimum decay time of 24 hours prior to fuel handling, the analysis demonstrates that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained < 0.063 Sv (6.3 rem) TEDE and < 0.05 Sv (5.0 rem) TEDE in the control room as required by 10 CFR 52.47(a)(2)(iv) (Ref. 2) and Regulatory Guide 1.183 (Ref. 3) acceptance criteria.

BASES

APPLICABLE SAFETY ANALYSES (continued)	While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped assembly, dropping an assembly on the RPV flange will result in reduced releases of fission gases. RPV Water Level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum water level of 7.01 m (23.0 ft) above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 4.
APPLICABILITY	LCO 3.9.6 is applicable during movement of irradiated fuel assemblies within the RPV and during movement of new fuel assemblies or handling of control rods (i.e., movement with other than the normal control rod drive) within the RPV when irradiated fuel assemblies are seated within the RPV. The LCO minimizes the possibility of a fuel handling accident in the reactor building that is beyond the assumptions of the safety analysis. If irradiated fuel is not being moved and is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.5, "Fuel Pool Water Level."
ACTIONS	<u>A.1</u> When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. If the water level is < 7.01 m (23.0 ft) above the top of the RPV flange, the movement of fuel assemblies and handling of control rods in the RPV is immediately suspended. Suspension of this activity shall not preclude completion of movement of a component to a safe position. This effectively precludes a fuel handling accident from occurring.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 7.01 m (23.0 ft) above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in the reactor building (Ref. 1).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Section 15.4.1.
2. 10 CFR 52.47(a)(2)(iv).
3. Regulatory Guide 1.183, July 2000.
4. NUREG-0800, Section 15.7.4.

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B 3.9 REFUELING OPERATIONS

B 3.9.7 Decay Time

BASES

BACKGROUND

The movement of irradiated fuel assemblies within the reactor pressure vessel (RPV) requires a minimum decay time of 24 hours to ensure that the initial fission product inventory in the damaged fuel assemblies is less than or equal to the assumptions used in the analysis of a fuel handling accident (Ref. 1). The fission product inventory in the damaged fuel rods in the analysis of a fuel handling accident is based on the days of continuous operation at full power. Due to plant cool down and disassembly operations, there is a time delay following initiation of reactor shutdown before fuel movement operations can be initiated. However, since it may be possible to be ready to move irradiated fuel assemblies in less than 24 hours after subcriticality, requiring a minimum decay time of 24 hours ensures that this assumption is met.

Assuming at least 24 hours of decay time, in conjunction with the minimum water level above the top of the RPV flange as required by LCO 3.9.6, "RPV Water Level," and minimum water level above the irradiated fuel assemblies in the spent fuel pools as required by LCO 3.7.5, "Fuel Pool Water Level," is sufficient to limit offsite doses from the accident to < 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) at the exclusion area boundary and < 0.05 Sv (5.0 rem) (TEDE) in the control room as required by 10 CFR 52.47(a)(2)(iv) (Ref. 2) and Regulatory Guide 1.183 (Ref. 3) acceptance criteria.

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies the fission product inventory in the fuel assemblies is an initial condition design parameter in the analysis of a fuel handling accident (Ref. 1). A decay time of 24 hours ensures the fission product inventory in the fuel rods is less than or equal to the value used in the fuel handling accident analysis. A fuel handling accident is assumed to damage all of the fuel rods in two (2) fuel assemblies as discussed in Reference 1.

Analysis of the fuel handling accident inside the reactor building or fuel building is described in Reference 1. With a minimum water level of 7.01 m (23.0 ft) above the RPV flange

BASES

APPLICABLE SAFETY ANALYSES (continued)	and above any irradiated fuel in the spent fuel storage racks, and a minimum decay time of 24 hours prior to fuel handling, the analysis demonstrates that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within < 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) and < 0.05 Sv (5.0 rem) in the control room as required by 10 CFR 52.47(a)(2)(iv) (Ref. 2) and Regulatory Guide 1.183 (Ref. 3) acceptance criteria. Decay Time satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum decay time of 24 hours is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 4.
APPLICABILITY	LCO 3.9.7 is applicable during movement of irradiated fuel assemblies within the RPV. The LCO ensures that the assumptions of the safety analysis of a fuel handling accident in the reactor building or fuel building are met, ensuring that the radiological consequences of a postulated fuel handling accident are within acceptable limits.
ACTIONS	<u>A.1</u> When the initial conditions for an accident analysis cannot be met, steps should be taken to preclude the accident from occurring. If the reactor has not been subcritical for at least 24 hours, the movement of irradiated fuel assemblies in the RPV is immediately suspended. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a fuel handling accident from occurring.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.7.1</u> Verification that the reactor has been subcritical for at least 24 hours prior to movement of irradiated fuel in the RPV ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Adequate decay time, and water at the required level,

BASES

SURVEILLANCE REQUIREMENTS (continued)	limit the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in the reactor building or fuel building (Ref. 1).
REFERENCES	1. Section 15.4.1. 2. 10 CFR 52.47(a)(2)(iv). 3. Regulatory Guide 1.183, July 2000. 4. NUREG-0800, Section 15.7.4.

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B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 5 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 93.3°C (200°F) (normally corresponding to MODE 3 or 4) or to allow completing these reactor coolant pressure tests when the initial conditions do not require temperatures > 93.3°C (200°F). Furthermore, the purpose is to allow continued performance of control rod scram time testing required by SR 3.1.4.1 or SR 3.1.4.4 if reactor coolant temperatures exceed 93.3°C (200°F) when the control rod scram time testing is initiated in conjunction with an inservice leak or hydrostatic test. These control rod scram time tests would be performed in accordance with LCO 3.10.4, "Control Rod Withdrawal – Cold Shutdown," during MODE 5 operation.

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.4, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing may eventually be required with minimum reactor coolant temperatures > 93.3°C (200°F). However, even with required minimum reactor coolant temperatures < 93.3°C (200°F), maintaining RCS temperatures within a small band during the test can be impractical. Removal of heat addition from reactor core decay heat is coarsely controlled by control rod drive hydraulic system purge flow and reactor water cleanup system non-regenerative heat exchanger operation. Test conditions are focused on maintaining a

BASES

BACKGROUND (continued)

steady state pressure, and tightly limited temperature control poses an unnecessary burden on the operator and may not be achievable in certain instances.

Other testing may be performed in conjunction with the allowances for inservice leak or hydrostatic tests and control rod scram time tests.

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 5 when the reactor coolant temperature is > 93.3°C (200°F), during, or as a consequence of, hydrostatic or leak testing, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, effectively provides an exception to MODE 3 and 4 requirements including OPERABILITY of containment and the full complement of redundant Emergency Core Cooling Systems. Since the tests are performed nearly water solid, at low decay heat values, and near MODE 5 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.3, "RCS Specific Activity," are minimized. In addition, the reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas will provide a boundary in accordance with this Special Operations LCO to contain airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak, with the reactor building REPAVS and CONAVS areas isolated, or capable of automatic isolation, will be conservatively bounded by the consequences of the postulated main steam line break (MSLB) outside of containment described in Reference 2. Therefore, requiring the reactor building REPAVS and CONAVS areas to be isolated, or capable of automatic isolation, will conservatively ensure that any potential airborne radiation from steam leaks will be held up, thereby limiting radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low-pressure core cooling systems to operate. The capability of the GDCS subsystems, as required in MODE 5 by LCO 3.5.3, "Gravity-Driven Cooling System (GDCS) – Shutdown," would be more than adequate to keep the core flooded under this low

BASES

APPLICABLE SAFETY ANALYSES (continued)

decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 5 applicable LCOs, in addition to the reactor building REPAVS and CONAVS areas requirements of this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criterion of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

Operation at reactor coolant temperatures > 93.3°C (200°F) can be in accordance with Table 1.1-1 for MODE 3 or 4 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 93.3°C (200°F). Performance of inservice leak and hydrostatic testing would also necessitate the inoperability of some subsystems normally required to be OPERABLE when > 93.3°C (200°F). Additionally, even with required minimum reactor coolant temperatures < 93.3°C (200°F), RCS temperatures may drift above 93.3°C (200°F) during the performance of inservice leak and hydrostatic testing or during subsequent control rod scram time testing, which is typically performed in conjunction with inservice leak and hydrostatic testing. While this Special Operations LCO is provided for inservice leak and hydrostatic testing, and for scram time testing initiated in conjunction with an inservice leak or hydrostatic test, parallel performance of others tests and inspections is not precluded.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 5 applicable LCOs, in addition to the reactor building REPAVS and CONAVS areas requirements of this Special Operations LCO, must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 5 to "N/A." The additional requirements for reactor building REPAVS and CONAVS areas to be isolated, or capable of automatic isolation, will provide

BASES

LCO (continued)

sufficient protection for operations at reactor coolant temperatures > 93.3°C (200°F) for the purposes of performing an inservice leak or hydrostatic test, and for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test.

This LCO allows primary containment to be open for frequent, unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 5 applicable requirements that are in effect immediately prior to, and immediately after, this operation.

APPLICABILITY

The MODE 5 requirements may only be modified for the performance of, or as a consequence of, the inservice leak or hydrostatic test, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, so that these operations can be considered as in MODE 5 even though the reactor coolant temperature is > 93.3°C (200°F). The additional requirement for reactor building REPAVS and CONAVS areas to be isolated, or capable of automatic isolation, provides conservatism in the response of the facility to any event that may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1 and A.2

Required Actions A.1 and A.2 restore compliance with the normal MODE 5 requirements and thereby exit this Special Operations LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are

BASES

ACTIONS (continued)

suspended immediately in accordance with Required Action A.1 and the reactor coolant temperature is reduced to establish normal MODE 5 requirements. The allowed Completion Time of 24 hours for Required Action A.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to ≤ 93.3°C (200°F) with normal cooldown procedures.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1 and SR 3.10.1.2

These Surveillances verify that the appropriate reactor building boundary is available to contain airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing.

The Surveillances are performed at 24 hour Frequencies to provide appropriate assurance of compliance with these Special Operations LCO requirements.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

2. Subsection 15.4.5.

Intentionally Blank

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, 5, and 6.

The reactor mode switch is a conveniently located, multi-function, multi-bank, control switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The Reactor Protection System (RPS) selects and bypasses the appropriate trip functions based on the position of the reactor mode switch. For the average power range monitor (APRM), oscillation power range monitor (OPRM), and startup range neutron monitor (SRNM) trip functions the Neutron Monitoring System (NMS) selects and bypasses the functions, not the RPS. The mode switch positions and related scram interlock functions are summarized in Reference 1.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram accumulator charging water header pressure trip bypass enable, refueling interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is preclude fuel failure by precluding reactivity excursions or core criticality.

The interlock functions of the shutdown and refuel positions of the reactor mode switch in MODES 3, 4, 5, and 6 are provided to preclude reactivity excursions which could potentially result in fuel failure. Interlock testing which requires moving the reactor mode switch to other positions (run, or startup) while in MODES 3, 4, 5, or 6, requires administratively maintaining all control rods inserted in core cells containing 1 or more fuel assemblies and no CORE ALTERATIONS in progress. There are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For postulated accidents such as control rod removal error during refueling (Ref. 2) or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur. The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criterion of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODE 3, 4, 5, and 6 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Control Rod Withdrawal - Hot/Stable Shutdown," LCO 3.10.4, "Control Rod Withdrawal - Cold Shutdown," and LCO 3.10.8, "Shutdown Margin (SDM) Test-Refueling") without meeting this LCO or its ACTIONS. If any testing is performed which involves the reactor mode switch interlocks and requires its repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, it can be performed provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, 5, and 6 with the reactor mode switch in shutdown per Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, 5, and 6 with the reactor mode switch in other than the shutdown position.

The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 6 operations, as discussed below, and is inherently met in MODES 3, 4, and 5 by the definition of CORE ALTERATIONS which cannot be performed with the vessel head in place.

In MODE 6, with the reactor mode switch in the refuel position, only one control rod or control rod pair can be withdrawn under the refuel position one-rod-out interlock

BASES

LCO (continued)

(LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS.

Due to the increased potential for error in controlling these multiple interlocks and the limited duration of tests involving the reactor mode switch position, conservative controls are required consistent with MODES 3, 4, and 5 operations. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch while in MODES 1 and 2 can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in plant trips. In MODES 3, 4, 5, and 6, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed while in other modes. Such interlock testing may consist of required surveillances or calibrations, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, 5, and 6, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS, if in progress, are immediately suspended in accordance with Required Action A.1 and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted. This will preclude potential mechanisms that could lead to criticality. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition.

BASES

ACTIONS (continued)

Placing the reactor mode switch to the shutdown position will ensure that all inserted control rods remain inserted and result in operation in accordance with Table 1.1-1. Alternatively, if in MODE 6, the reactor mode switch must be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Action is not applicable in MODES 3, 4, and 5 since only the shutdown position is allowed in these MODES. The allowed Completion Time of one hour for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position based on operating experience and is acceptable given that all operations which could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in shutdown (or refuel for MODE 6). The functions of the reactor mode switch interlocks, which are not in effect due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls to ensure that the operational requirements continue to be met are to be periodically verified. The Surveillances performed at the 12-hour and 24-hour Frequency are intended to provide appropriate assurance that each operating shift is aware of and verify compliance with these Special Operations LCO requirements.

REFERENCES

1. Subsection 7.2.1.5.

2. Subsection 15.3.7.

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Control Rod Withdrawal - Hot/Stable Shutdown

BASES

BACKGROUND	The purpose of this MODES 3 and 4 Special Operations LCO is to permit the withdrawal of a single control rod or control rod pair for testing while in shutdown by imposing certain restrictions. In MODES 3 and 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions due to other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances will arise while in MODES 3 and 4 which present the need to withdraw a single control rod or control rod pair for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod or dual control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. A control rod pair (those associated by a shared control rod drive hydraulic control unit) may be withdrawn by utilizing the SINGLE/GANG rod selection status in the GANG rod selection mode, which "gangs" the two rods together for rod position and control purposes. This Special Operations LCO provides the appropriate additional controls to allow a single control rod, or control rod pair, withdrawal in MODES 3 and 4.
APPLICABLE SAFETY ANALYSES	With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODES 3 and 4, these analyses will bound the consequences of an accident. The safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions. Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod (or control rod pair). Under these conditions, the core will always be shut down even with the highest worth control rod pair withdrawn if adequate SDM exists.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod pairs have been established for each control rod drive hydraulic control unit (except for the center rod which has its own accumulator). These pairs are selected and analyzed so that adequate SDM is maintained with any control rod pair fully withdrawn.

When the SINGLE/GANG rod selection status in the GANG rod selection mode is used, the selected rod pair is substituted for a single rod within the appropriate logic in order to satisfy the refuel mode one-rod/rod-pair-out interlock. The rod pair may then be withdrawn simultaneously.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

Alternate backup protection can be obtained by assuring that a five-by-five array of control rods, centered on each withdrawn control rod, are inserted and incapable of withdrawal.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 and 4 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod or control rod pair withdrawal is desired in MODE 3 or 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod or control rod pair can be withdrawn.

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod(s) in the event of an inadvertent criticality is provided by this Special

BASES

LCO (continued)	Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod(s) are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of these control rods is sufficiently precluded so as not to require the scram capability of the withdrawn control rod(s). Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.
APPLICABILITY	Control rod withdrawals are adequately controlled in MODES 1, 2, and 6 by existing LCOs. In MODES 3, 4, and 5, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, "Control Rod Withdrawal – Cold Shutdown," and if limited to one control rod or control rod pair. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod/rod-pair-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication"), full insertion requirements for all other control rods and scram functions (LCO 3.3.1.1 "Reactor Protection System (RPS) Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation") and LCO 3.9.5, "Control Rod OPERABILITY – Refueling," or the added administrative control in Item d.2 of this Special Operations LCO minimizes potential reactivity excursions.
ACTIONS	A Note has been provided to modify the ACTIONS related to a single control rod or control rod pair withdrawal while in MODES 3 and 4. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, trains, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the

BASES

ACTIONS (continued)

LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. This Required Action has been modified by a Note that clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods and to also require exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. A second Note has been added which clarifies that this action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternative ACTIONS that can be taken instead of Required Action A.1 and are provided to restore compliance with the normal MODE 3 or 4 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of one hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod(s) is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. SR 3.10.3.2 has been modified by a Note that clarifies that this SR is not required to be met if

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod(s) being withdrawn are fully inserted. The 24-hour Frequency is acceptable because of the administrative controls on control rod withdrawals and the protection afforded by the LCOs involved, and hardware interlocks that preclude additional control rod withdrawals.
REFERENCES	1. Subsection 15.3.7.

Intentionally Blank

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Control Rod Withdrawal - Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the withdrawal of a single control rod or control rod pair for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 5, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances will arise while in MODE 5, however, that present the need to withdraw a single control rod or control rod pair for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive(s) (CRDs). These single or dual control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch. A control rod pair (those associated by a single CRD hydraulic control unit) may be withdrawn by utilizing the SINGLE/GANG rod selection status in the GANG rod selection mode, which "gangs" the two rods together for rod position and control purposes. This Special Operations LCO provides the appropriate additional controls to allow a single or dual control rod withdrawal in MODE 5.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 5, these analyses will bound the consequences of an accident. The safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod or control rod pair. Under these conditions, the core will always be shut down even with the highest worth control rod pair withdrawn if adequate SDM exists.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Control rod pairs have been established for each control rod drive hydraulic control unit (except for the center rod, which has its own accumulator). These pairs are selected and analyzed so that adequate SDM is maintained with any control rod pair fully withdrawn. When the SINGLE/GANG rod selection status is in the GANG rod selection mode, only one rod pair with the same hydraulic control unit can be withdrawn in order to satisfy the refuel mode one-rod/rod-pair-out interlock. The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by assuring that a five-by-five array of control rods, centered on the withdrawn control rod(s), are inserted and incapable of withdrawal. This alternate backup protection is required when removing the CRDs because this removal renders the withdrawn control rod(s) incapable of being scrammed. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODE 5 operations with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod or control rod pair withdrawal is desired in MODE 5, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod(s) as well as maintaining the control rod(s) in a position other than the full-in position, and reinserting the control rod(s). The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock," required by this Special Operations LCO will ensure that only one control rod or control rod pair can be withdrawn. At the time CRD removal

BASES

LCO (continued)

begins, the disconnection of the position indication probe(s) will cause LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained. To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod(s) in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod(s) are required to be inserted and made incapable of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod(s). Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod(s) and the highest worth control rod(s) may be changed to allow the withdrawn-untrippable control rod(s) to be the highest worth control rod(s).

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 6 by existing LCOs. In MODES 3, 4, and 5, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO and if limited to one control rod or control rod pair. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod/rod-pair-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1 "Reactor Protection System (RPS) Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation"), and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

BASES

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod or control rod pair withdrawal while in MODE 5. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, trains, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 5 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 is modified by two Notes. Note 1 clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods and to also require exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. Note 2 has been added to Required Action A.1 to clarify that this action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified based on the condition of the control rod(s) being withdrawn. If a control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within one hour, place the reactor mode switch in the shutdown position. Actions must continue until all such control rods are fully inserted. The allowed Completion Time of one hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

BASES

ACTIONS (continued)

B.1, B.2.1, and B.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod(s) not insertable, withdrawal of the control rod and removal of the associated control rod drive must immediately be suspended. If the CRD has been removed such that the control rod is not insertable, these ACTIONS require the most expeditious action be taken to either restore the CRD and insert its control rod or restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. Also, all the control rods are verified to be inserted as well as the control rod withdrawal block. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted provides assurance that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The 24-hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes that clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. Subsection 15.3.7.

Intentionally Blank

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Control Rod Drive (CRD) Removal - Refueling

BASES

BACKGROUND

The purpose of this MODE 6 Special Operations LCO is to permit the removal of a CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod or control rod pair is permitted to be withdrawn from a core cell containing one or more fuel assemblies. The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all-rods-in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod/rod-pair-out interlock will not allow the withdrawal of a second control rod. A control rod drive pair (those associated by a shared CRD hydraulic control unit) may be removed under the control of the one-rod/rod-pair-out interlock by utilizing the SINGLE/GANG rod selection status in the GANG rod selection mode. This switch allows the CRD pair to be treated as one CRD for purposes of the one-rod-out interlock.

The control rod scram function provides backup protection to normal refueling procedures, as do the refueling interlocks described above, which prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure that the possibility of an inadvertent criticality is precluded while allowing a single CRD or control rod drive pair to be removed from core cells containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod/Rod-Pair-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic system, thereby causing inoperability of the control rod (LCO 3.9.5, Control Rod OPERABILITY - Refueling).

BASES

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of accidents. The safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions.

Control rod pairs have been established for each control rod drive hydraulic control unit (except for the center rod, which has its own accumulator). These pairs are selected and analyzed so that adequate SDM is maintained with any control rod pair fully withdrawn. When the SINGLE/GANG rod selection status in the GANG rod selection mode is used, the selected rod pair is substituted for a single rod within the appropriate logic in order to satisfy the refuel mode one-rod/rod-pair-out interlock. The rod pair may then be withdrawn simultaneously.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod or control rod pair. Under these conditions, the core will always be shut down even with the highest worth control rod or control rod pair withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod/rod-pair-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all-rods-in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks that prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by assuring that a five-by-five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn (by insertion of a control rod block).

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 6 with any of the following LCOs – LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.1.2 "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 - not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD or CRD drive pair removal from a core cell containing one or more fuel assemblies is desired in MODE 6, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.1.3, LCO 3.3.1.4, LCO 3.3.1.5, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod/rod-pairout interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS (item d) adequately compensates for the inoperable all-rods-in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five-by-five array of control rods, centered on each withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection that LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.1.3, LCO 3.3.1.4, LCO 3.3.1.5, and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod(s) and the highest worth control rod(s) may be changed to allow the withdrawn-untrippable control rod(s) to be the highest worth control rod(s).

BASES

LCO (continued)

The exception granted in this Special Operations LCO to assume that the withdrawn control rod or control rod pair be the highest worth control rod(s) to satisfy LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," and the inability to withdraw another control rod during this operation without additional SDM demonstrations, is conservative (i.e., the withdrawn control rod or control rod pair may not be the highest worth control rod(s)).

APPLICABILITY

MODE 6 operations are controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.1.3, LCO 3.3.1.4, LCO 3.3.1.5, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduces the potential for reactivity excursions.

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.1.3, LCO 3.3.1.4, LCO 3.3.1.5, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require these ACTIONS be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD(s) and insert its control rod(s) or restore compliance with this Special Operations LCO. Actions must continue until either required Action A.2.1 or required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods other than the control rod withdrawn for the removal of the associated CRD are fully inserted is required to assure the SDM is within limits. Verification that the local five-by-five array of control rods other than the control rod withdrawn for the removal of the associated CRD is inserted and disarmed while

BASES

SURVEILLANCE REQUIREMENTS (continued)	the scram function for the withdrawn rod is not available is required to ensure that the possibility of criticality remains precluded. Verification that a control rod withdrawal block has been inserted provides assurance that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to assure the assumptions of the safety analysis are satisfied. Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24-hour Frequency is acceptable given the administrative controls on control rod removal and hardware interlocks to block an additional control rod withdrawal.
REFERENCES	1. Subsection 15.3.7.

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B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal - Refueling

BASES

BACKGROUND

The purpose of this MODE 6 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod or control rod pair is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell the control rods may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all-rods-in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod/rod-pair-out interlock will not allow the withdrawal of additional control rods.

To allow more than one control rod (pair) to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

The safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN will prevent unacceptable reactivity excursions during refueling. To allow multiple (e.g., more than one control rod or control rod pair) control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from the cell. With no fuel assemblies in the core cell, the

BASES

APPLICABLE SAFETY ANALYSES (continued)	associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 6 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY – Refueling," not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO any fuel remaining in a cell whose control rod was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. When loading fuel into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Spiral reloading encompasses reloading a cell (four fuel locations immediately adjacent to a control rod) on the edge of a continuous fueled region (the cell can be loaded in any sequence). Otherwise, all control rods must be fully inserted before loading fuel.
APPLICABILITY	Operation in MODE 6 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

BASES

ACTIONS

A.1, A.2, A.3.1, and A.3.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2, Required Action A.3.1, and Required Action A.3.2 are intended to require that these ACTIONS be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24-hour Frequency is acceptable given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.

REFERENCES

1. Subsection 15.3.7.

Intentionally Blank

B 3.10 SPECIAL OPERATIONS

B 3.10.7 Control Rod Testing - Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing while in MODES 1 and 2 by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation") such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RWM. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a Rod Withdrawal Error (RWE). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests may include SDM demonstrations, control rod scram time testing, control rod friction testing, and testing performed during the Startup Test Program. This Special Operations LCO provides the necessary exceptions to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the RWE are summarized in Reference 1. RWE analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the RWE analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the RWE analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analyses of Reference 1 may not be preserved and, therefore, special RWE analyses are required to demonstrate that these special sequences will not result in unacceptable consequences should a RWE occur during the testing. These analyses are dependent on the specific test being performed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations

BASES

APPLICABLE SAFETY ANALYSES (continued)	LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed, in compliance with the prescribed sequences of LCO 3.1.6, and during these tests no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence remain valid. When deviating from the prescribed sequences of LCO 3.1.6, individual control rods must be bypassed in the Rod Control and Instrumentation System (RC&IS). Assurance that the test sequence is followed can be provided by a second licensed operator or other qualified member of the technical staff verifying conformance to the approved test sequence. These controls are consistent with those normally applied to operation in the startup range as defined in SR 3.3.2.1.9 when it is necessary to deviate from the prescribed sequence (e.g., an inoperable control rod that must be fully inserted).
APPLICABILITY	Control rod testing while in MODES 1 and 2 with THERMAL POWER greater than 10% RTP of the RWM is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "LINEAR HEAT GENERATION RATE (LHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this Special Operations LCO are necessary to perform special tests which are not in conformance with the prescribed control rod sequences of LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Control Rod Withdrawal - Shutdown" or Special Operations LCO 3.10.4, "Control Rod Withdrawal - Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 2 is satisfied. During these Special Operations and while in

BASES

APPLICABILITY (continued)	MODE 6, the one-rod/rod-pair-out interlock (LCO 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.1.2 "Reactor Protection System (RPS) Actuation," LCO 3.3.1.3, "Reactor Protection System (RPS) Manual Actuation," LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, minimize potential reactivity excursions.

ACTIONS

A.1

With the requirements of this Special Operations LCO not met (e.g., the control rod pattern not in compliance with the special test sequence), the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer exempted and appropriate actions are to be taken either to restore the control rod sequence to the prescribed sequence of LCO 3.1.6 or to shut down the reactor if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

During performance of the special test, a second licensed operator or other qualified member of the technical staff is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. This Surveillance provides adequate assurance that the specified test sequence is being followed and is also supplemented by SR 3.3.2.1.9, which requires verification of the bypassing of control rods in RC&IS and subsequent movement of these control rods.

REFERENCES

1. Section 15.3.8.
2. Section 15.3.7.

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B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test - Refueling

BASES

BACKGROUND	The purpose of this MODE 6 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned. LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 6 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 6, the reactor mode switch is required to be in the shutdown or refuel position where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup position since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup position while in MODE 6, is provided by the Startup Range Neutron Monitor (SRNM) neutron flux scram and control rod block instrumentation. The limiting reactivity excursion during startup conditions while in MODE 6 is the Rod Withdrawal Error (RWE) event. RWE analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of Reference 1 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analysis may not be met and, therefore, special RWE

BASES

APPLICABLE SAFETY ANALYSES (continued)	analyses are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a RWE occur during the testing. For the purpose of this test, protection provided by the normally required MODE 6 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Ref. 1). In addition to the added requirements for the RWM, APRM, and control rod coupling, the notch movement mode is specified for out-of-sequence withdrawals. Requiring the notch movement mode limits withdrawal steps to a single notch, which limits inserted reactivity and allows adequate monitoring of changes in neutron flux that may occur during the test. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2 in accordance with Table 1.1-1 without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 6, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required SRNMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2, LCO 3.3.1.2, "Reactor Protection System (RPS) Actuation," LCO 3.3.1.4 "Neutron Monitoring System (NMS) Instrumentation," Functions 2.a and 2.d, and LCO 3.3.1.5, "Neutron Monitoring System (NMS) Automatic Actuation," Function 2) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.2.1, "Control Rod Block Instrumentation", Function 1.b, MODE 2), or must be verified by a second licensed operator or other qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the ganged withdrawal sequence restrictions

BASES

LCO (continued)

(GWSR) specified in LCO 3.1.6, "Rod Pattern Control" (i.e., out-of-sequence control rod withdrawals) must be made in the notch movement mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a RWE and ensure proper functioning of the withdrawn control rods if required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. In addition, the reactor building refueling and pool area HVAC subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas will provide a boundary as required to mitigate the consequences of an inadvertent criticality. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup position such that the SDM tests may be performed while in MODE 6.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 6 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1 and A.2

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required. Operation may continue, provided the control rods are fully inserted within 3 hours and disarmed within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. Required Action A.1 is modified by a Note that allows control rods to be bypassed in accordance with SR 3.3.2.1.9, if required, to allow insertion of inoperable control rod and continued operation. SR 3.3.2.1.9 provides additional requirements when the control rods are bypassed to ensure compliance with the RWE analysis.

BASES

ACTIONS (continued)

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met, for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 6 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1 Function 2, LCO 3.3.1.2, LCO 3.3.1.4, Functions 2.a and 2.d, and LCO 3.3.1.5, Function 2 made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 1.b, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5 and SR 3.10.8.6

These Surveillances verify that the appropriate reactor building boundary is available to mitigate the consequences of an inadvertent criticality.

The Surveillances are performed at 24 hour Frequencies to provide appropriate assurance of compliance with these Special Operations LCO requirements.

SR 3.10.8.7

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

REFERENCES

1. Subsection 15.3.8.

Intentionally Blank

B 3.10 SPECIAL OPERATIONS

B 3.10.9 Oxygen Concentration - Startup Test Program

BASES

BACKGROUND	Testing performed as part of the Startup Test Program (Ref. 1), requires containment entries to inspect components following the performance of some tests. LCO 3.6.1.8, "Containment Oxygen Concentration," requires the containment to be inerted with the oxygen concentration maintained below 4.0 volume percent (v/o). This Special Operations LCO provides appropriate restriction to allow containment entries for the required Startup Test Program without having increased personnel risks due to an oxygen deficient atmosphere.
APPLICABLE SAFETY ANALYSES	The containment oxygen concentration is maintained below 4.0 v/o to ensure that an event which produces any amount of hydrogen does not result in a combustible mixture inside containment. The time allowed with the requirements for containment inerting suspended is sufficiently short such that the probability of an event requiring an inerted atmosphere is very low. Additionally, due to the minimal exposure of the fuel, the decay heat and fission product levels are not significant. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. However, to perform portions of the Startup Test Program it is impractical to have the containment inerted. To minimize the probability of an accident that assumes an inerted containment, the requirements of LCO 3.6.1.8 are only allowed to be suspended during the initial 120 effective full power days of operation.

BASES

APPLICABILITY	Suspension of the requirements for containment inerting with THERMAL POWER > 15% RTP are applied during the Startup Test Program up to 120 effective full power days of operation. This minimizes the probability of an event requiring an inerted containment and also minimizes the decay heat and fission product levels in the fuel.
ACTIONS	A.1 With the requirements of the LCO not met, the provisions of LCO 3.6.1.8 are no longer exempted and the appropriate ACTIONS of the affected LCO (LCO 3.6.1.8) are required to be taken. The Required Action is provided to restore compliance with the Technical Specification overridden by this Special Operations LCO. Compliance will also result in exiting the Applicability of this Special Operations LCO.
SURVEILLANCE REQUIREMENTS	SR 3.10.9.1 Periodic verification of the allowed 120 effective full power days of operation established by the LCO provides adequate assurance the reactor is operated within the bounds of the LCO. The 7-day Frequency is acceptable given the slow and predictable change in time of core operation.
REFERENCES	1. Chapter 14.

B 3.10 SPECIAL OPERATIONS

B 3.10.10 Oscillation Power Range Monitor (OPRM) - Initial Cycle

BASES

BACKGROUND	The OPRMs provide trip signals to the RPS. The OPRM trip protection includes algorithms that detect thermal hydraulic instability (flux oscillation with unacceptable amplitude and frequency) as described in the Bases for LCO 3.3.1.4, "NMS Instrumentation." To ensure adequate implementation of the OPRM algorithms and to avoid unnecessary spurious reactor scrams, the system will be checked during the startup test program. Final OPRM configuration development and deployment to achieve better balance between defense-in-depth protection and inadvertent scram avoidance would be implemented prior to startup from the first cycle refueling outage. During the initial cycle, reactor instability protection is provided by the backup stability protection (BSP) (Ref. 1). If the entry to the BSP region (as defined in Ref. 1) is inadvertent or forced, immediate exit from the region is required. The region can be exited by control rod insertion or FW temperature maneuvering. The guidance and actions recommended by the BSP emphasize instability prevention to minimize the burden placed on the operator when monitoring for the onset of power oscillations. Therefore, caution is required whenever operating near the BSP Region boundary, and it is recommended that the amount of time spent operating near this region be minimized.
APPLICABLE SAFETY ANALYSES	The OPRM – Upscale Function is not credited in the safety analysis and is included in the Technical Specifications as a defense-in-depth feature. The OPRM – Upscale Function is provided as a backup to other RPS Functions and the Selected Control Rod Run-In/ Select Rod Insert (SCRRI/SRI) function. As such, the BSP (Ref. 1) provides adequate protection for the initial cycle of operation. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional and therefore no specific criteria of 10 CFR 50.36(c)(2)(ii) applies. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.

BASES

LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. However, to perform the OPRM checkout and minimize the potential for unnecessary spurious reactor scram, the requirements for OPRM OPERABILITY are allowed to be suspended. Appropriately trained on-shift operations staff can implement the alternate method to detect and suppress thermal hydraulic instability oscillations (Ref. 1) should they occur.
APPLICABILITY	Suspension of the requirements for OPRM OPERABILITY is allowed during the initial cycle of operation. To ensure adequate implementation of the OPRM algorithms and to avoid unnecessary spurious reactor scrams, the system is evaluated during the startup test program. Any necessary OPRM configuration development and deployment is implemented prior to startup from the first cycle refueling outage.
ACTIONS	<u>A.1</u> With the requirements of the LCO not met, ACTIONS appropriate to inoperable OPRM consistent with the actions of LCO 3.3.1.4 and LCO 3.3.1.5 are required. In this condition, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The 4 hour Completion Time is reasonable, based on engineering judgment, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems. Compliance will also result in exiting the Applicability of this Special Operations LCO.
SURVEILLANCE REQUIREMENTS	<u>SR 3.10.10.1</u> Periodic verification of on-shift operations staff training on alternate method to detect and suppress thermal hydraulic instability oscillations supports this Special Operation allowance. The 92-day Frequency is acceptable to provide reasonable assurance of the necessary operations staff training for BSP.
REFERENCES	1. Section 4D.3.3.

BASIS: ESBWR COLA
(Entirety)

North Anna 3 Combined License Application

Part 5: Emergency Plan

Revision 5

December 2013

Explanatory Notes Regarding the Emergency Plan and Supplemental Information

The North Anna Power Station Unit 3 Combined License Emergency Plan consists of a basic plan and eight appendices. The basic plan follows the format of NUREG-0654 and provides detailed information regarding each of the sixteen Planning Standards and associated Evaluation Criteria. The eight appendices that follow provide additional detailed information on various aspects of the Emergency Plan. Supplemental information includes the detailed evacuation time estimate report and current state and local emergency planning documents. Emergency Planning Inspections, Test, Analyses, and Acceptance Criteria (ITAAC) are included in Part 10 of the COLA.

REVISION SUMMARY

Revision 5

Section	Changes	Reason for Change
II.A.1.b	Revised to clarify the Emergency Coordinator Function	EF3 RAI 13.03-74
II.H.2	Added a pointer to Section II.N.2	EF3 RAI 13.03-72
II.N.2	Added text to clarify drill and exercise schedules	EF3 RAI 13.03-72
Appendix 8	Revised to clarify the Emergency Coordinator Function	EF3 RAI 13.03-78

Revision 4

Section	Changes	Reason for Change
Expanatory Notes, I.B, II.A.1.b, II.D, II.D.1, II.D.2, II.I.1, II.P.7, III.A.13, Appendix 1, Appendix 8	RAI 13.03-3- Revised, Emergency Action Levels	
II.A.1.b, II.A.3	Revised to reflect consolidation of certification letters and title change to National Response Framework	Consistency with Rev. 3 (based on US-APWR COLA)
II.B.9	Added reference to supporting offsite response organizations	Revision to 10 CFR 50, Appendix E, Section IV.A.7 (consistency with Rev. 3)
	Revised to reflect consolidation of certification letters	Consistency with Rev. 3
II.C.1.a	Deleted option for contacting FRMAC directly	Reflect NRC-preferred method of requesting Federal assistance (consistency with Rev. 3)
II.C.4	Revised to reflect consolidation of certification letters	Consistency with Rev. 3
II.C.5, II.C.6	Added	Address NSIR/DPR-ISG-01 Section IV.K
II.D.2	Added information about evaluating and declaring events	Address revision to 10 CFR 50, Appendix E, Section IV.C.2
II.E.1	Added information about notifying state and local officials within 15 minutes of emergency declaration	Consistency with North Anna Units 1 & 2 Emergency Plans

Revision 4 *(continued)*

Section	Changes	Reason for Change
II.E.6	Added information about route alerting	Addresses revision to 10 CFR 50, Appendix E, Section IV.D.4
II.F.1	Added reference to FSAR for communication links information	EF3 RAI 13.03-12
II.H	Revised reference to SSAR	Editorial
II.H.1, II.H.2	RAI 13.03-4, Clarify Change to HSI Function From SPDS Function	
II.H.2	RAI 13.03-5, Clarify New EOF	
	Clarified the location of the local EOF	Addresses SER OI 13.03-5
II.H.4	Added information about staging areas for staff augmentation for hostile actions	Addresses revision to 10 CFR 50, Appendix E, Section IV.E.8
II.H.5	Changed “Sections” to “Section”	Editorial; consistency with Rev. 3
II.H.8	Added reference to met system description	Consistency with Rev. 3
II.H.9	Clarified the location of the OSC	Addresses SER OI 13.03-8
II.J.7	Added information to address evacuations and protective actions	Addresses EF3 RAIs 13.03-14 and 13.03-61
II.J.8	Revised to address the updated ETE report	2012 ETE Report, and addresses revision to 10 CFR 50, Appendix E, Section IV.4
II.J.10	Changed “Figures 10-1 through 10-4” to “Figure 10-1 and Figure 10-2”	Addresses 2012 ETE Report
Figure II-4	Updated map to North Anna remote assembly areas	Consistency with Rev. 3
II.L.1	Revised to reflect consolidation of certification letters	Consistency with Rev. 3
II.N.1-2	Clarified periodic drills and exercises	Addresses revision to 10 CFR 50, Appendix E IV.F.2 and NSIR/DPR-ISG-01, Section IV.g
II.P.4	Clarified ETE review and updates	Addresses revision to 10 CFR 50, Appendix E, Section IV.5 and IV.6

Revision 4 *(continued)*

Section	Changes	Reason for Change
II.N.4, II.P.1, II.P.3, II.P.4, II.P.10	Changed “Emergency Planning Coordinator” to “Manager Emergency Preparedness”	Consistency with Rev. 3
III.A	Updated references 12 and 18; added references 20 and 21	Documents revised and new documents
III.B	Added NSIR/DPR-ISG-01	New reference
III.C	Revised to reflect consolidation of certification letters	Consistency with Rev. 3
Appendix 2–1.0	Changed reference from “Section II.I” to “SSAR Section 2.3”	Correction
Appendix 2–2.3	Changed reference from “Section II.F of this emergency plan” to “SSAR Section 2.3”	Correction
Appendix 2–3.0	Deleted reference to SSAR Section 2.3.3; in last three bullets, changed “Section xxx of the NAESP application” to “SSAR Section xxx”; changed references to Generic ITAAC to COLA Part 10	Corrections
Appendix 4	Replaced with Executive Summary from updated ETE report	Evacuation Time Estimate Report was updated in 2012
Appendix 7	Replaced individual certification letters with consolidated certification letter	Consistency with Rev. 3
Appendix 8 (Note)	Revised to reflect consolidation of certification letters	Consistency with Rev. 3
	Added evaluation criteria C.5 and C.6	Address NSIR/DPR-ISG-01, Section IV.K
	Added evaluation criterion N.1.c	Address NSIR/DPR-ISG-01, Section IV.G
Supplement	Replaced with 2012 ETE report	Evacuation Time Estimate Report was updated in 2012

Revision 1

Section	Changes
I, I.C.2, I.C.3, II.A, II.B, II.C, II.D, II.D.2, II.E, II.E.2, II.E.6, II.E.7, II.F, II.G, II.H, II.H.4, II.I, II.I.7, II.J, II.J.8, II.K, II.L, II.O, II.P, III.A.19, Appendix 1–Executive Summary, Appendix 1–1.0, Appendix 1–3.0	RAI 13.03-2.2, IBR is SSAR in ESPA versus ESP
I.A, I.B, I.C.3, II.A.1.b, II.B.1, II.H.2, II.H.5.a, II.H.5.b, II.H.5.c, II.H.5.d, II.K.2, II.L.1, II.N.2.b, II.P.9, III.A.9, III.A.10, III.A.19, IC HU4, Appendix 2–1.0, Appendix 2–2.1, Appendix 2–2.2, Appendix 8	Made references to Unit 3. Editorial changes. Corrected references. Added reference to MD plan (Appendix 8). Updated Appendix 4 with ETE R1 executive summary.
II.B.8, II.C.3	RAI 13.03-2.3, Vendor Support During Emergency Events
II.E.1, II.F.1.d	Added locations of ENS access and description of communication capabilities between the Control Room/TSC and radiological field personnel.
II.G.4.a, II.G.4.c	RAI 13.03-2-8, Classification of Titles in Public Information Structure
II.H.1, II.H.2	Corrected description of technical data display in TSC.
Table II-2	RAI 13.03-2.9, Required Minimum Staffing Times
II.J.10.a, Figure II-5	RAI ETE-4, Evacuation Routes, Monitoring Points, and Shelter Locations
II.P.4	Changed FSRC to proper noun.
Appendix 1–Executive Summary	Deleted incorrect reference.
Appendix 8	Editorial corrections.

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Acronyms and Abbreviations

AED	Automatic External Defibrillator
ALARA	As Low As Reasonably Achievable
CDE	Committed Dose Equivalent
CFR	Code of Federal Regulations
COL	Combined License
COVRERP	Commonwealth of Virginia Radiological Emergency Response Plan
CPR	Cardio-Pulmonary Resuscitation
CR	Control Room
DCD	Design Control Document
DEQ	Department of Environmental Quality
DHS	(U.S.) Department of Homeland Security
DOE	(U.S.) Department of Energy
EAL	Emergency Action Level
EAS	Emergency Alert System
EDE	Effective Dose Equivalent
ENS	Emergency Notification System
EOC	Emergency Operations Center
EOF	Emergency Operations Facility
EPA	(U.S.) Environmental Protection Agency
EPIP	Emergency Plan Implementing Procedure
EPZ	Emergency Planning Zone
ERDS	Emergency Response Data System
ERF	Emergency Response Facility
ERO	Emergency Response Organization
ESP	Early Site Permit
ETE	Evacuation Time Estimate
FEMA	Federal Emergency Management Agency
FRMAC	Federal Radiological Monitoring and Assessment Center
FRMAP	Federal Radiological Monitoring Assessment Plan
FSAR	Final Safety Analysis Report
GUI	Graphic User Interface
HEAR	Hospital Emergency Alerting Radio
HPN	Health Physics Network
INPO	Institute of Nuclear Power Operations
ITAAC	Inspections, Tests, Analyses and Acceptance Criteria
JIC	Joint Information Center
LAN	Local Area Network
LCO	Limiting Condition of Operation

MIDAS	Meteorological Information and Dose Assessment System
MIDAS-NU	MIDAS-Nuclear
NAEP	North Anna Emergency Plan
NAPS	North Anna Power Station
NEI	Nuclear Energy Institute
NOAA	(U.S.) National Oceanographic and Atmospheric Administration
NOUE	Notification of Unusual Event
NRC	(U.S.) Nuclear Regulatory Commission
NWS	(U.S.) National Weather Service
ODCM	Offsite Dose Calculation Manual
ORO	Offsite Response Organization
OSC	Operational Support Center
PAG	Protective Action Guide
PAR	Protective Action Recommendation
PMCL	Protective Measures Counterpart Link
POI	Point of Interest
QA	Quality Assurance
RERP	Radiological Emergency Response Plan
RM/F	Radiation Monitors and Flow
RPP	Radiation Protection Program
RSCL	Reactor Safety Counterpart Link
SOSC	State On Scene Coordinator
SPDS	Safety Parameter Display System
Sv	Sievert
REAC/TS	Radiation Emergency Assistance Center / Training Site
SPDS	Safety Parameter Display System
TEDE	Total Effective Dose Equivalent
TSC	Technical Support Center
UHF	Ultra High Frequency
VCUMC	Virginia Commonwealth University Medical Center
VDEM	Virginia Department of Emergency Management
VDH	Virginia Department of Health
WAN	Wide Area Network

I. Introduction

This emergency plan describes the plans established by Dominion for responding to a radiological emergency at North Anna Power Station (NAPS) Unit 3. Portions of this plan incorporate content by reference from Part 2, Site Safety Analysis Report, of the North Anna ESPA (Reference 19). This plan uses the format “SSAR Section x.y.z” to identify content incorporated from Part 2 of the ESPA.

A. Purpose

This Emergency Plan describes the pre-planned facilities, equipment, response organizations, assessment and protective actions, and cooperative agreements established by Dominion to provide for adequate protection of life and property in the event of a radiological emergency at Unit 3. In this context, protection of life and property includes:

- Notifying and mobilizing affected members of the licensee staff, Federal, Commonwealth of Virginia, risk jurisdiction, and commercial response organizations, and the public;
- Limiting the radiological impact of the emergency on plant employees and affected members of the public; and
- Limiting the potential adverse impact of protective actions, such as evacuations or sheltering.

The impact of plant emergencies is limited through the implementation of pre-planned and controlled preparatory, assessment, and protective actions consistent with this plan.

B. Scope

This emergency plan applies to planning for and response to any radiological emergency condition at Unit 3. Section II.D describes the emergency classification system. Implementing procedures identify radiological emergency conditions, their initiating conditions, and Emergency Action Levels (EALs).

This emergency plan has been coordinated with the plans of affected government agencies and private sector support organizations listed in Section II.A. Ongoing coordination with affected risk jurisdiction, Commonwealth of Virginia, and Federal agencies and private sector support organizations is imperative to provide for an effective emergency response capability.

C. Planning Basis and Emergency Planning Zones

1. Planning Basis

This plan has been developed to meet the requirements of 10 CFR Part 52, “Early Site Permits; Standard Design Certifications; and Combined Licenses For Nuclear Power Plants,” (Reference 1). Consistent with those requirements, this plan is based on the requirements of 10 CFR Part 50, “Domestic Licensing Of Production And Utilization

Facilities," (Reference 2) primarily Section 50.47, "Emergency Plans," (Reference 3) and Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities" (Reference 4). This plan is also based on the guidance provided in NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (Reference 5).

2. Emergency Planning Zones

NUREG-0654 establishes two Emergency Planning Zones (EPZs) for which planning for predetermined actions should be implemented – the plume exposure pathway EPZ, which has a radius of approximately ten miles, and the ingestion exposure pathway EPZ, which has a radius of approximately fifty miles. When recommending the size of these EPZs in 1978, the NRC/EPA Task Force on Emergency Planning considered the 1975 Reactor Safety Study (WASH-1400) (Reference 6). The NRC/EPA Task Force on Emergency Planning determined that this study was the best available source of information on the relative likelihood of large accidental releases of radioactivity, given a core melt event (Reference 7). Since that time, significant advances have been made in understanding the timing, magnitude, and chemical form of fission product releases from severe nuclear power plant accidents (Reference 8). The plan recognizes that the size of these areas is subject to change if later analyses, design-specific factors, and legislative or regulatory initiatives warrant.

Plume Exposure Pathway EPZ

The plume exposure pathway EPZ is that area where the principal sources of incident-related radiation exposures are likely to be whole body gamma radiation exposures and inhalation exposures from the passing radioactive plume. As a result of this exposure scenario, any exposures resulting from a radiological incident at the facility are likely to have a duration from less than one hour to a few days.

The plume exposure pathway EPZ consists of an area about 10 miles in radius around the site. Figure I-1 provides an illustration of the plume exposure pathway EPZ. The description of the plume exposure pathway EPZ in SSAR Section 13.3.2.2.1 is incorporated by reference. Collectively, the affected counties are referred to as the risk jurisdictions.

Ingestion Exposure Pathway EPZ

The ingestion exposure pathway EPZ is that area where the principal sources of incident-related radiation exposures are likely to result from ingestion of contaminated water and food, including milk, fresh vegetables, and aquatic foodstuffs. As a result of this exposure scenario, any exposures resulting from a radiological incident at the facility are likely to have a duration from a few hours to months.

The ingestion exposure pathway EPZ consists of an area about 50 miles in radius around the site. Figure I-2 provides an illustration of the ingestion exposure pathway EPZ. The description of the Ingestion Exposure Pathway EPZ in SSAR Section 13.3.2.2.1 is incorporated by reference.

3. Site and Area Description

Unit 3 consists of a General Electric - Hitachi (GEH) ESBWR as described in the ESBWR Design Control Document (DCD) (Reference 9) and the associated Final Safety Analysis Report (FSAR) (Reference 10).

The site and area descriptions in SSAR Section 13.3.2.1.1 are incorporated by reference.

Figure I-1 North Anna Site Plume Exposure Pathway EPZ

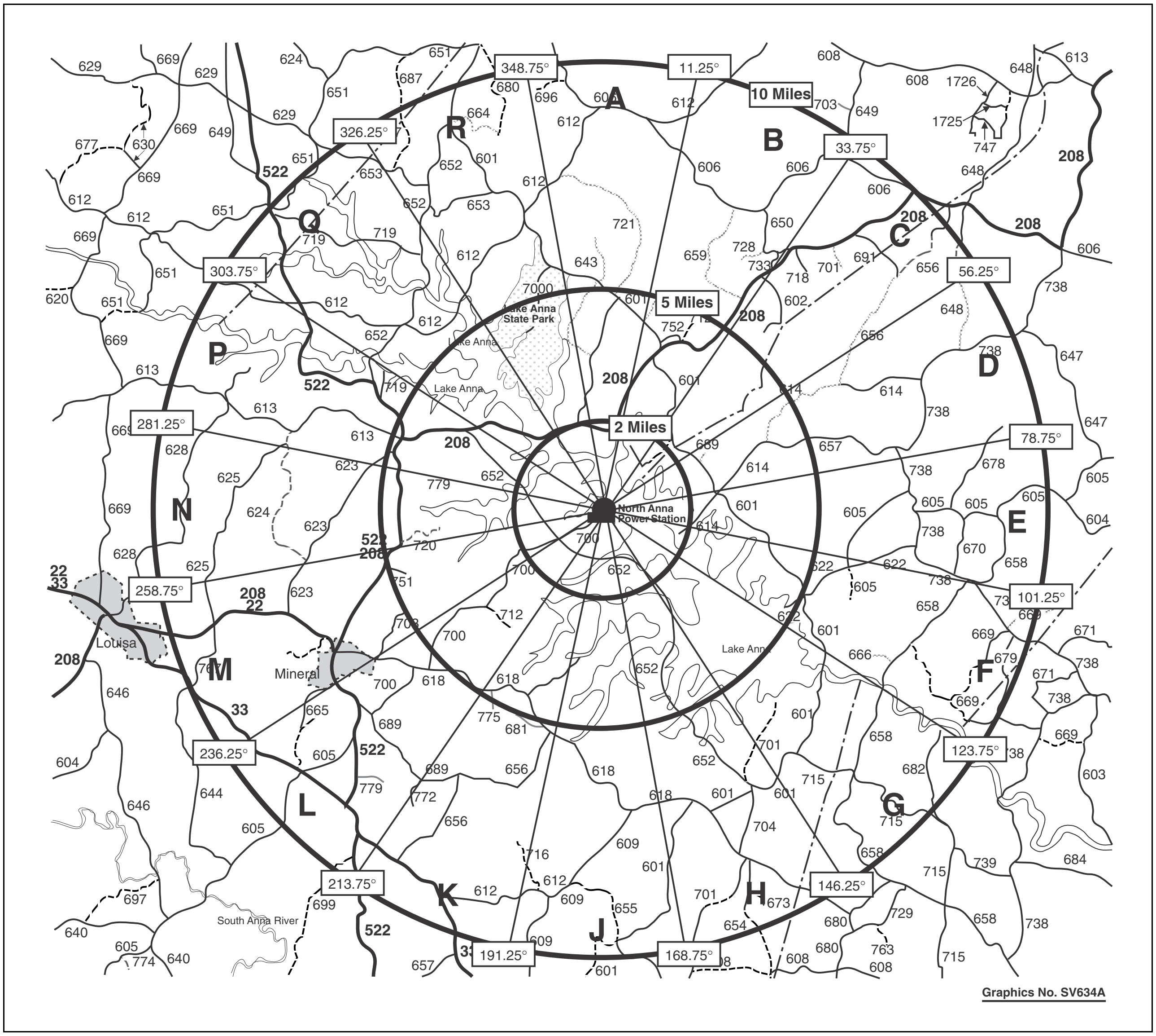
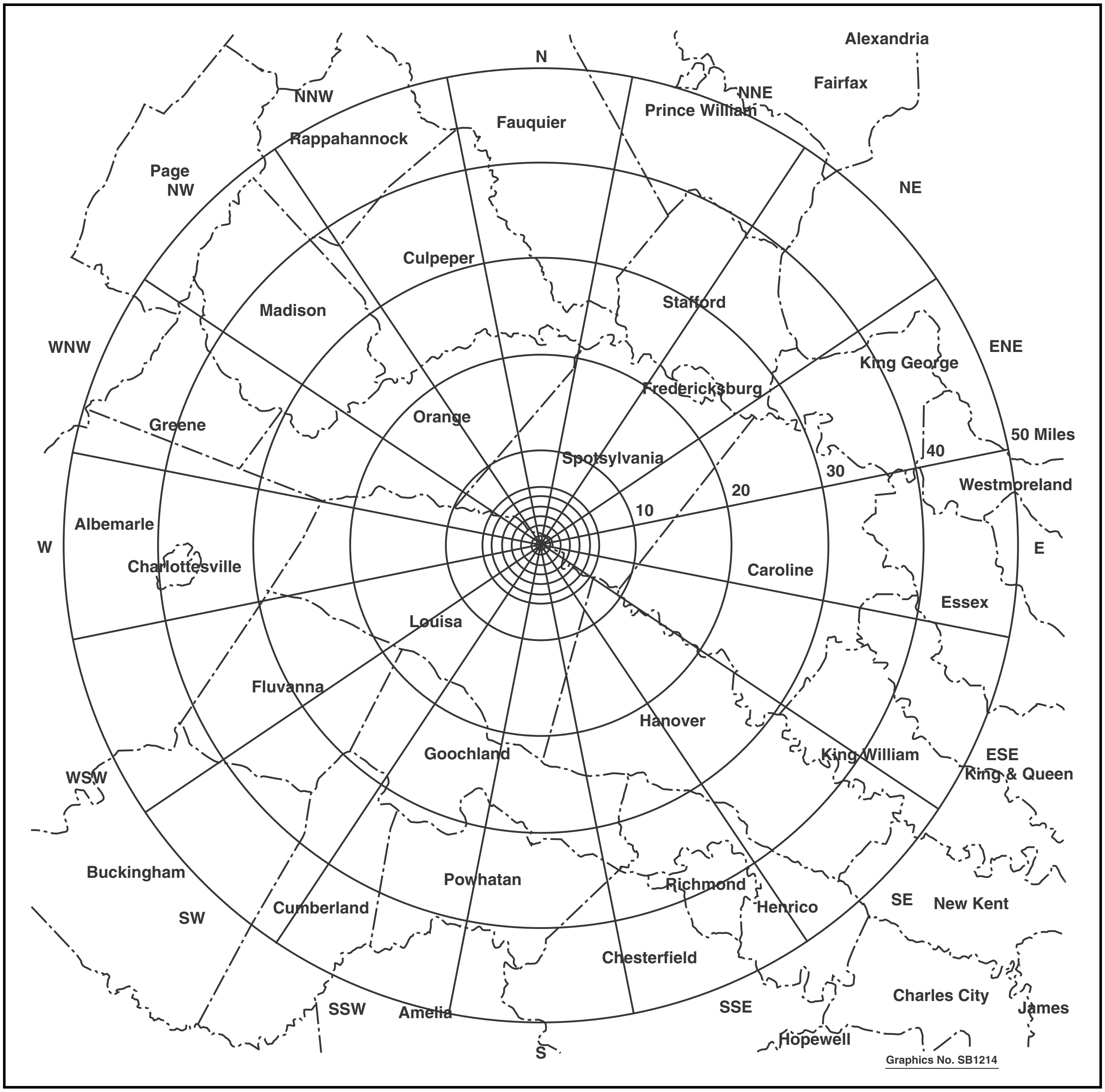


Figure I-2 North Anna Site Ingestion Exposure Pathway EPZ



II. Emergency Plan

A. Assignment of Responsibility (Organization Control)

The description of participating organizations in SSAR Section 13.3.2.2.2.a is incorporated by reference.

1. Emergency Organization

a. Participating Organizations

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Concept of Operations

Dominion's responsibilities during an emergency condition focus on taking actions to:

- Assess plant conditions
- Classify emergency conditions
- Notify affected agencies of emergency conditions
- Provide technical expertise to affected agencies
- Provide support for offsite assessment and protective activities
- Make protective action recommendations
- Mitigate the consequences of adverse plant conditions by monitoring and controlling plant parameters
- Request assistance from off-site agencies, as needed
- Provide support to affected agencies for communications with the affected public
- Terminate emergency conditions

Normal operations at Unit 3 are conducted under the authority of the Shift Manager and directed from the Unit 3 Control Room. In the event of an abnormal condition, the Shift Manager directs the activities of the plant staff in performing initial assessment, corrective, and protective functions. Using approved operating procedures, including the EALs provided in implementing procedures, the Shift Manager determines if an emergency condition exists and, if so, the proper emergency classification. Based on this classification and plant conditions, the Shift Manager assumes the role of the *Emergency Coordinator*[1], makes or directs initial notifications to affected plant staff

1. Throughout this plan, certain position titles, such as *Emergency Coordinator* and *EOF Director*, are used consistent with the provisions of existing regulations, guidance, and Dominion documents. The position titles are provided in italics to denote their generic application. The actual position titles to be used in the execution of this plan will be established in emergency plan implementing procedures or other facility documentation.

and Commonwealth of Virginia, risk jurisdiction, and Federal authorities, and determines if activation of the Dominion emergency response facilities (ERFs) is desirable or required.

The Unit 3 Control Room is the initial center for coordination of emergency response affecting the unit. For emergencies classified as Alert, Site Area Emergency and General Emergency, the *Emergency Coordinator* directs the activation of the emergency response organization (ERO)[2,3,4]. The *Emergency Coordinator* may direct the activation of all or part of the ERO for a Notification of Unusual Event, based on an assessment of plant conditions and support needs.

The Unit 3 Technical Support Center (TSC) acts in support of the command and control function of the Unit 3 Control Room. The TSC provides an area for station personnel who have expertise in diverse areas of plant operation to support the emergency response. This facility is equipped with communication equipment, computer terminals, printers, off-site and on-site computer access, plant drawings, procedures and other materials and equipment to support its function. Personnel in the TSC assess the accident condition and make recommendations to the Control Room, the Emergency Operations Facility (EOF) and off-site agencies as necessary to provide for the safety of plant personnel and members of the general public. After the EOF is operational and activated, the EOF assumes many of the functions of the TSC and relies on the TSC as a vital link to the station. The TSC provides the EOF with up-to-date plant parameters, which allows the EOF staff to perform its assigned tasks.

Following activation of the ERFs and receipt of an adequate turnover, the *Site Vice President* or other designated member of the station management staff relieves the Shift Manager of *Emergency Coordinator* responsibilities and directs the activities of the on-site emergency response organization from the TSC. If the EOF is activated, the *EOF Director* assumes responsibility for the licensee’s offsite emergency response efforts, coordinates the availability and utilization of corporate and external resources, and manages recovery efforts.

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2. If an event is transient in nature such that staffing of the ERO is not practical prior to termination of the event, then the ERO may not be staffed; however, notifications to affected authorities will be completed consistent with the requirements of this plan.
3. The ERO may be staffed prior to the declaration of an emergency situation, such as in anticipation of severe weather that is likely to result in the declaration of an emergency condition.
4. Under some circumstances, such as unanticipated natural events or hostile action against the facility, the *Emergency Coordinator* may judge that movement of personnel as needed to staff the emergency response facilities may create undue personnel hazards. Under such circumstances, the Emergency Coordinator may elect to postpone staffing of the emergency response facilities and implement compensatory measures as needed to provide for ongoing personnel and facility safety.

The Operational Support Center (OSC) provides an operational center to provide support to the TSC and Control Room. The OSC dispatches assessment and repair teams as directed by the *Emergency Coordinator*, providing operational information, radiological assessment, and manpower for in-plant functions.

Table II-1, Responsibility for Emergency Response Functions, summarizes the responsibilities and activities of the ERFs under the various emergency classifications.

Coordination with NAPS Units 1&2

Dominion has identified the need to coordinate emergency response actions taken at Unit 3 with Units 1&2. As noted previously in this section the *Emergency Coordinator* is responsible for making notifications to affected plant staff, which may include the Unit 1&2 Control Room. This notification and subsequent communications are important to apprise the Unit 1&2 staffs of any actions they may be required to take.

Additionally, in the unlikely event that emergencies are declared at Unit 3 simultaneously with Unit 1 or 2, the Unit 3 Shift Manager fulfills the *Emergency Coordinator* function until relieved as previously noted in this section. The *Emergency Coordinator* discharges those duties described in this Emergency Plan, as well as those described in the Unit 1&2 Emergency Plan and provides for coordination of activities between the on-site ERFs.

Coordination with Other Reactor Sites Serviced by Central Emergency Operations Facility

In the unlikely event that the Central Emergency Operations Facility described in Section II.H.2 is activated for emergencies that are declared at Unit 3 simultaneously with another reactor site it services, the EOF Director discharges those duties described in this Emergency Plan, as well as those described in the other affected site's Emergency Plan.

Commonwealth of Virginia Government Response

The Commonwealth of Virginia organization for response to radiological emergencies is based on normal governmental structures and channels of communication. The Governor directs the emergency response through the State Coordinator of the Virginia Department of Emergency Management (VDEM). The State Coordinator of the VDEM coordinates the overall response, and the Virginia Department of Health (VDH) provides technical advice and assistance on radiological accident assessment, protective action, radiological control, and radiological monitoring.

When notification is received, the COVRERP is implemented and the VDH initiates action to assess and evaluate the radiological situation in order to provide guidance and assistance to risk jurisdiction governments. After the initial immediate actions, subsequent protective actions are implemented based on the results of the Commonwealth of Virginia evaluation of the radiological situation and the company's recommendations. Commonwealth of Virginia and Federal agencies provide assistance as required. Response operations at the state level are coordinated by the VDEM.

The Commonwealth of Virginia also provides police support during activation of this plan. The first response is likely to be from police units normally based in the local area. These resources can be supplemented as needed by additional units dispatched from other parts of the state. The Virginia State Police also provides traffic control and additional security.

The State Coordinator of the VDEM coordinates the overall response operations at the state level and performs specific duties as defined in the Virginia Emergency Operations Plan, Radiological Emergency Response Basic Plan. The Virginia Emergency Operations Center (EOC) is located at 7700 Midlothian Turnpike, Richmond, Virginia. There are local EOCs in the risk jurisdictions. The VDH sends appropriate liaison personnel to the EOF upon activation.

VDH personnel provide technical advice and assistance on radiological accident assessment, protective actions, radiological exposure control, and radiological monitoring. Virginia EOC staffing is augmented when notification is received of a radiological emergency classified as an Alert or above. Included in the planned response is a team sent to the EOF, which provides direct interface between the VDH and the company's radiological assessment personnel.

Additional Commonwealth of Virginia organizations having possible responsibilities in a radiological emergency are listed in the COVRERP. Requests for support services from these organizations are coordinated through the VDEM.

Figure II-1, Emergency Response Organization Interrelationships, depicts the interrelationships among the various Commonwealth of Virginia and Federal organizations that may respond to an emergency at the facility.

Risk Jurisdiction Government Emergency Response

Responsibility for radiological emergency response rests primarily with the elected officials of local governments. As time is a major factor in realizing the benefits of protective action in the event of a radiological emergency, certain of these actions are predetermined and agreed upon by the local governing body and are implemented without delay upon notification of a radiological emergency. An Insta-phone with backup by commercial telephone, having extensions available in the Control Room, TSC and EOF, is used for normal transmission of emergency notifications to these authorities. Receipt of message by Insta-phone constitutes verification. If the message was received by means other than by Insta-phone, procedures for authentication of an emergency, via the use of call-back numbers, are maintained in the COVRERP and risk jurisdiction RERPs. Risk jurisdiction law enforcement personnel also respond to these Plans. They can perform essentially the same functions as the Virginia State Police and coordinate their efforts with that organization.

In the event of an emergency, the Station is in communication with the risk jurisdiction Emergency Services Directors, who have the capability of activating their EOCs. The Station relies upon the risk jurisdictions to provide assistance in the event an evacuation from the site requires a remote assembly point or for any services the risk jurisdictions are capable of providing to mitigate the results of the emergency.

The risk jurisdiction health department is the primary health response agency, with the Virginia Health Department providing assistance to them as required, with emphasis on the special requirements for those individuals who are contaminated with radioactivity. Accident assessment personnel operate from the Virginia EOC.

In the event of an emergency, notification and coordination with the risk jurisdictions within the ingestion exposure pathway EPZ are the responsibility of the VDEM and VDH in cooperation with the Virginia Department of Agriculture and Consumer Services and the Virginia Department of Environmental Quality (DEQ), Water Division.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

Federal Government Emergency Response

The Station also maintains close contact with the NRC Operations Center and/or the NRC Region II offices in Atlanta, Georgia. This is an important function to provide accurate information and assessment of the emergency to the Federal Government. As a result of these communications, the NRC can best appraise their response to the emergency. In a like manner, the U.S. Department of Energy, Oak Ridge Operations, is available to provide radiological assistance to the Station.

The Federal Radiological Monitoring and Assessment Center (FRMAC) Operations Plan (Reference 11) provides for the coordinated management of Federal technical response activities related to a radiological emergency. Its primary goals include:

- Assisting the Commonwealth of Virginia and Federal Coordinating Agency with personnel, equipment, and technical resources, as needed;
- Collecting offsite environmental radiological data; and,
- Providing the data and related assessments to involved State agencies and to the Federal Coordinating Agency.

The Department of Energy (DOE), because of its history and capabilities in radiological monitoring and assessment, was assigned the responsibility to prepare for, establish, and manage the FRMAC. The FRMAC may be activated when a major radiological emergency exists, and the Federal government responds when a State, other governmental entity with jurisdiction, or a regulated entity requests federal support.

Further information concerning objectives and organization is provided in the FRMAC Operations Plan.

Appendix 7 provides a copy of the certification letter established between Dominion and the supporting Commonwealth of Virginia and risk jurisdiction agencies and private sector organizations supporting this plan. The responsibilities of many Federal agencies are established in the National Response Framework (Reference 12) and therefore no agreement letters are required for these agencies.

c. Organizational Interrelationships

The interfaces between and among the onsite and offsite functional areas of emergency response described in SSAR Section 13.3.2.2.2.b.1 are incorporated by reference. Figure II-1 illustrates these interrelationships.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

d. Individual in Charge of Emergency Response

In the event of an abnormal condition, the Shift Manager determines if an emergency condition exists and, if so, classifies the emergency. Upon declaration of an emergency, the Shift Manager or Unit Supervisor assumes the role of the *Emergency Coordinator* and is in charge of the emergency response for the facility.

If required by the emergency classification, or if deemed appropriate by the *Emergency Coordinator*, emergency response personnel are notified and instructed to report to their emergency response locations[5]. The Shift Manager is relieved as *Emergency Coordinator* when the designated management representative reports to

5. See Section II.A.1.a of this plan regarding situations under which staffing of the emergency response facilities may be deferred.

the station and is updated as to the status of the unit, the emergency actions taken, and the current status of the emergency. Following this relief, the *Emergency Coordinator* may relocate to the TSC.

The EOF may be activated concurrent with the TSC and always is activated upon declaration of a Site Area Emergency or General Emergency. The EOF is staffed by Dominion personnel, including the *EOF Director*, who directs the activities of this facility. The senior Dominion representative is responsible for ensuring the EOF communicates emergency status to the Commonwealth of Virginia and risk jurisdiction governments, directs the efforts of the offsite monitoring teams, makes radiological assessments, recommends offsite protective measures to the Commonwealth of Virginia, and arranges through the company for dispatch of any special assistance or services requested by the station.

The Director Nuclear Protection Services and Emergency Preparedness reports to Dominion's senior nuclear executive who is responsible for the total execution of the radiological emergency response effort at Dominion's fleet of nuclear power plants.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

e. 24 Hour Emergency Response Capability

Dominion maintains capability for 24 hour response, including staffing of communications links, through training of multiple responders for key emergency response positions, consistent with the staffing requirements of Section II.B.5 and the training requirements of Section II.O.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Functions, Responsibilities, and Legal Basis

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. Written Agreements

Appendix 7 provides a copy of the certification letter established between Dominion and the Commonwealth of Virginia and risk jurisdiction government agencies and private sector organizations committed to supporting further development and implementation of this plan.

The responsibilities of many Federal agencies are established in the National Response Framework; therefore, no certification letters are required for these agencies.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Continuous Operations

Dominion maintains capability for continuous operations through training of multiple responders for key emergency response positions, consistent with the training requirements established in Section II.O. The *Emergency Coordinator* bears responsibility for ensuring continuity of technical, administrative, and material resources during emergency operations.

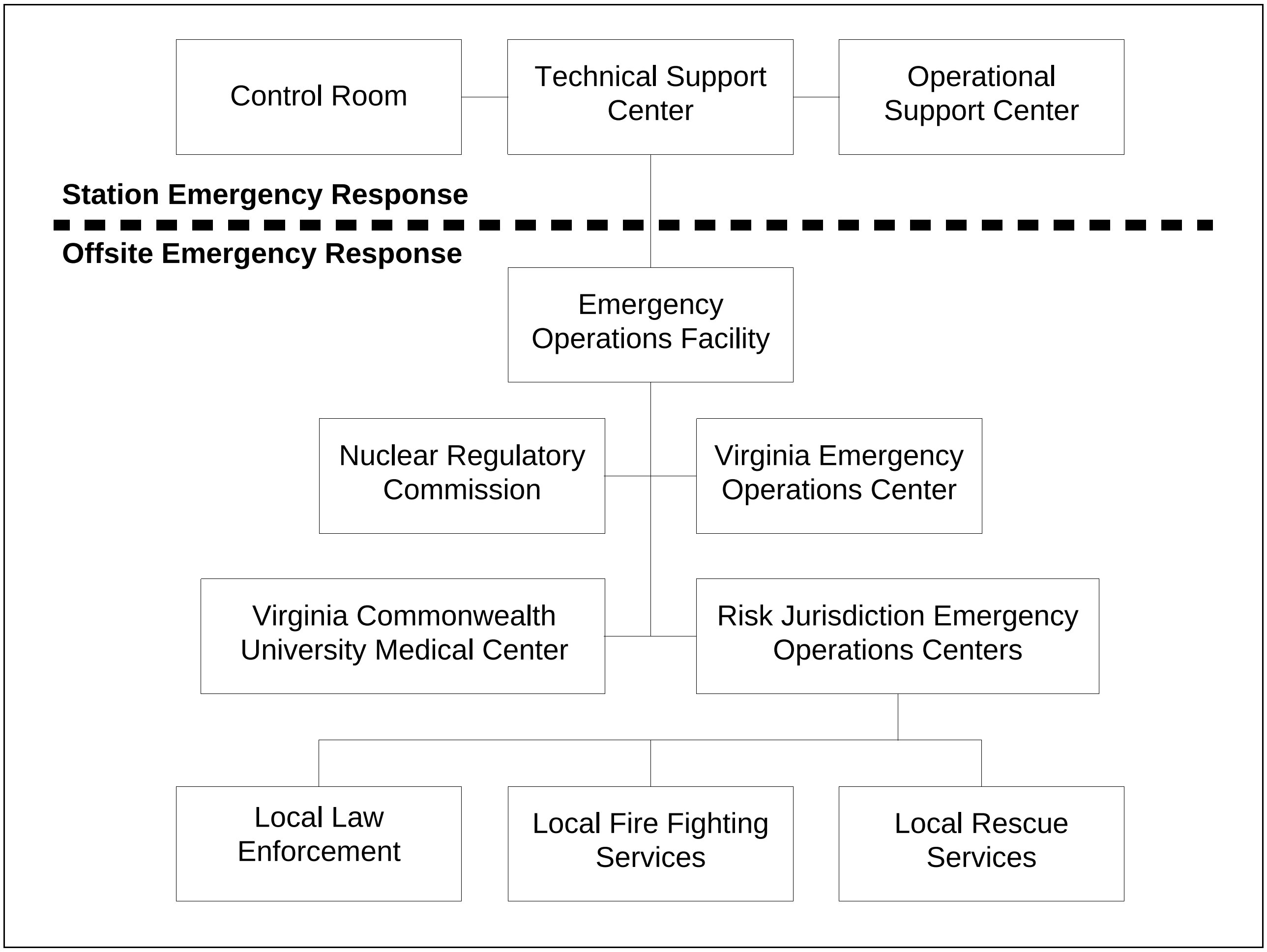
Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

Table II-1 Responsibility for Emergency Response Functions

	Emergency Classification			
Function	**NOUE**	**Alert**	**Site Area Emergency**	**General Emergency**
Supervision of reactor operations and manipulation of controls	CR	CR	CR	CR
Management of plant operations	CR (TSC)	TSC	TSC	TSC
Technical support for reactor operations	CR (TSC)	TSC	TSC	TSC
Management of corporate emergency response resources	CR (TSC) (EOF)	TSC (EOF)	EOF	EOF
Monitoring of radioactive effluents and the environs; dose assessment and projection	CR (TSC) (EOF)	TSC (EOF)	EOF	EOF
Provision of information to Commonwealth of Virginia and risk jurisdiction emergency response organizations, including Protective Action Recommendations	CR (TSC) (EOF)	TSC (EOF)	EOF	EOF
Management of recovery operations	CR (TSC) (EOF)	TSC (EOF)	TSC/EOF	TSC/EOF
Technical support for recovery operations	CR (TSC) (EOF)	TSC (EOF)	TSC/EOF	TSC/EOF

Note: Listing of facilities in parentheses indicates that activation of these facilities or performance of these functions is optional, based on management assessment of plant conditions and emergency response needs.

Figure II-1 Emergency Response Organization Interrelationships



B. Onsite Emergency Organization

1. Onsite Emergency Organization

The description of the Onsite Emergency Organization in SSAR Section 13.3.2.2.2.b is incorporated by reference.

Figure II-2 illustrates the onsite emergency response organization (ERO). EPIPs provide details regarding ERO position functions.

The minimum staff required to conduct routine and immediate emergency operations is maintained at the station consistent with 10 CFR 50.54(m) and this plan. Staffing is described in FSAR Section 13.1. Station administrative procedures provide the details of the normal station organization, including reporting relationships.

Upon declaration of an emergency, designated members of the normal staff complement fulfill corresponding roles within the emergency response organization. For example, Health Physics personnel undertake radiation protection activities, Security personnel undertake Security activities, Engineering personnel focus on plant assessment and technical support for operations, and Operations personnel focus on plant operations.

2. Emergency Coordinator

The Shift Manager/Unit Supervisor position is continuously staffed consistent with 10 CFR 50.54(m). Upon recognition of an emergency condition, the individual filling this position assumes the duties of the *Emergency Coordinator* until relieved by a qualified member of the management staff consistent with Section II.B.3 or until termination of the emergency condition, whichever comes first.

The individual filling the *Emergency Coordinator* role has the responsibility and authority to initiate any required emergency response actions, including notification of affected Federal, Commonwealth of Virginia, and risk jurisdiction authorities and provision of Protective Action Recommendations to offsite authorities. Upon staffing of the ERO, the *EOF Director* relieves the *Emergency Coordinator* of responsibility for notification of and coordination with offsite authorities.

3. Emergency Coordinator Line of Succession

If the Shift Manager is rendered unable to fulfill the duties and responsibilities of the *Emergency Coordinator* position (such as due to personal illness or injury) the Unit Supervisor or, in the absence of a Unit Supervisor (i.e., as may be permitted in cold shutdown or refueling modes), a Reactor Operator present on shift (a position that also will be continuously staffed) assumes the *Emergency Coordinator* position until relieved by a qualified member of the management staff as outlined below.

A trained, higher level member of the licensee’s management staff may assume *Emergency Coordinator* responsibilities from the Shift Manager after becoming fully familiar with the pertinent plant and radiological conditions and status of emergency response/accident mitigation efforts.

4. Emergency Coordinator Responsibilities

The *Emergency Coordinator* has the responsibility and authority to initiate emergency actions necessary to protect the life, health, and safety of the plant staff. Any required evacuations of individuals (including members of the public) from the plant’s Exclusion Area are conducted cooperatively with Commonwealth of Virginia and risk jurisdiction agencies. The non-delegable responsibilities of the *Emergency Coordinator* include:

- Classifying the emergency
- Authorizing notification to the NRC, Commonwealth of Virginia and risk jurisdiction agencies of the emergency status
- Recommending protective measures

- Authorizing emergency exposure limits

Other responsibilities of the *Emergency Coordinator* include:

- Activating emergency personnel and facilities
- Reducing power or shutting down the reactor
- Committing company funds as necessary
- Acquiring emergency equipment or supplies
- Ordering site evacuation
- Restricting access to the site
- Notifying company management
- Implementing work schedules
- Directing onsite emergency activities

As indicated in Table II-1, the EOF may assume responsibility for:

- Management of corporate emergency response resources
- Monitoring of radioactive effluents and the environs
- Dose assessment and dose projections, including recommending protective measures
- Provision of information regarding emergency status to offsite emergency response support organizations, including notification to the NRC, the Commonwealth of Virginia, and the risk jurisdiction agencies

5. Plant Emergency Response Staff

Dominion will establish minimum emergency response staffing consistent with Table II-2, which has been based on the guidance provided in Table B-1 of NUREG-0654. Figure II-2 illustrates the plant staff emergency organization.

Upon declaration of an emergency, members of the plant staff assume positions in the emergency response organization consistent with their training and management assignments. Figure II-3 provides an illustration of the augmented plant staff emergency response organization.

The ERO, when fully activated, includes the positions described in Table II-2. Additional personnel may be designated as emergency responders providing special expertise deemed beneficial, but not mandatory, to the planned response. The individuals assigned as responders for the emergency positions are designated based on the technical requirements of the position.

The onsite emergency organization provides for the key functions of accident assessment, radiological monitoring and analysis, security, fire-fighting, first aid and rescue, and communications.

6. Interfaces Between Functional Areas

Figure II-1 illustrates the interfaces between and among the site functional areas of emergency response activity, Dominion EOF support, the affected Commonwealth of Virginia and risk jurisdiction government response organizations, the NRC, and other offsite organizations.

7. Corporate Support for the Plant Staff

Upon declaration of an Alert, Site Area Emergency, or General Emergency, the *Emergency Coordinator* directs the activation and notification of the onsite and offsite ERFs. Dominion management, technical, and administrative personnel staff the EOF and provide (or coordinate) augmented support for the plant staff.

The Dominion corporate staff focuses on discharging management, technical and administrative activities as needed to support the plant staff and to relieve the plant staff of external coordination responsibilities, including notification of and coordination with offsite authorities and release of information to the media. In addition to the activities discussed in Table II-2, activities of the Dominion corporate staff include:

- Logistical support for plant personnel
- Technical support for planning and recovery/re-entry operations
- Management-level interface with governmental authorities
- Coordination with, and release of information to, the news media

8. Support from Contractor and Private Organizations

The Institute of Nuclear Power Operations (INPO) serves as a clearinghouse for industry wide support during an emergency. When notified of an emergency situation, INPO provides emergency response as requested. INPO provides the following emergency support functions:

- Assistance to the affected utility in locating sources of emergency manpower and equipment
- Analysis of the operational aspects of the incident
- Dissemination to member utilities of information concerning the incident
- Organization of industry experts who could advise on technical matters

If requested, one or more suitably qualified members of the INPO staff will report to the *EOF Director* and assist in coordinating INPO's response to the emergency.

Dominion may request that the reactor vendor, GEH, provide technical support for emergency response activities. GEH will operate primarily from its corporate offices, with a small contingent at the plant if requested.

If required at the time of the event, additional resources can be obtained through purchase agreements with the supporting institutions. These agreements would be negotiated on an as-needed basis.

9. Risk Jurisdiction Emergency Response Support

Dominion has established and will maintain agreements for risk jurisdiction emergency response support services, including fire fighting, rescue squad, medical and hospital services. Section II.L of this plan provides a description of the arrangements for medical support services, including hospital and ambulance support. Appendix 7 provides the certification letter for organizations providing these services.

Figure II-2 North Anna Unit 3 Emergency Response Organization – On-Site

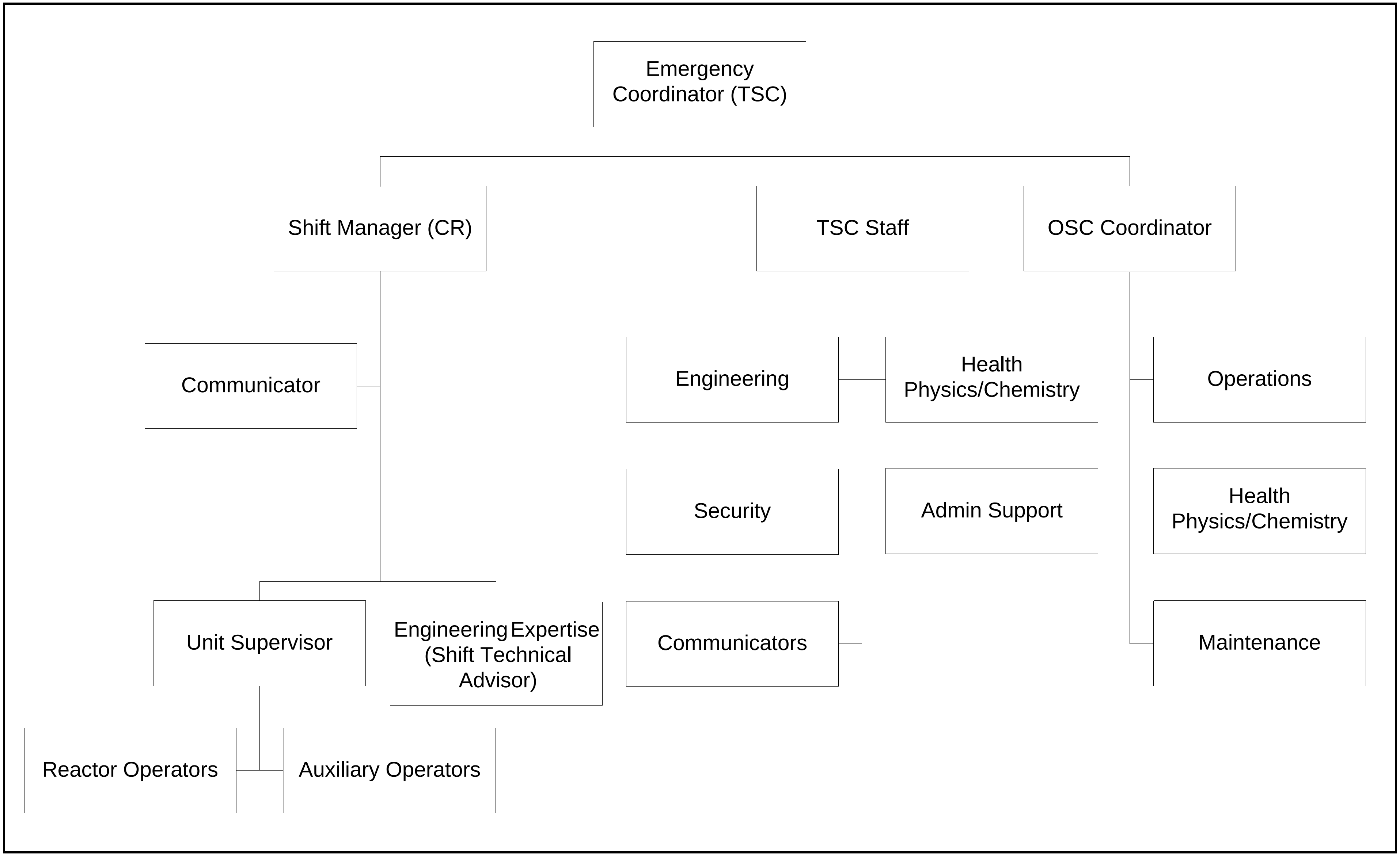


Figure II-3 North Anna Unit 3 Augmented Emergency Response Organization

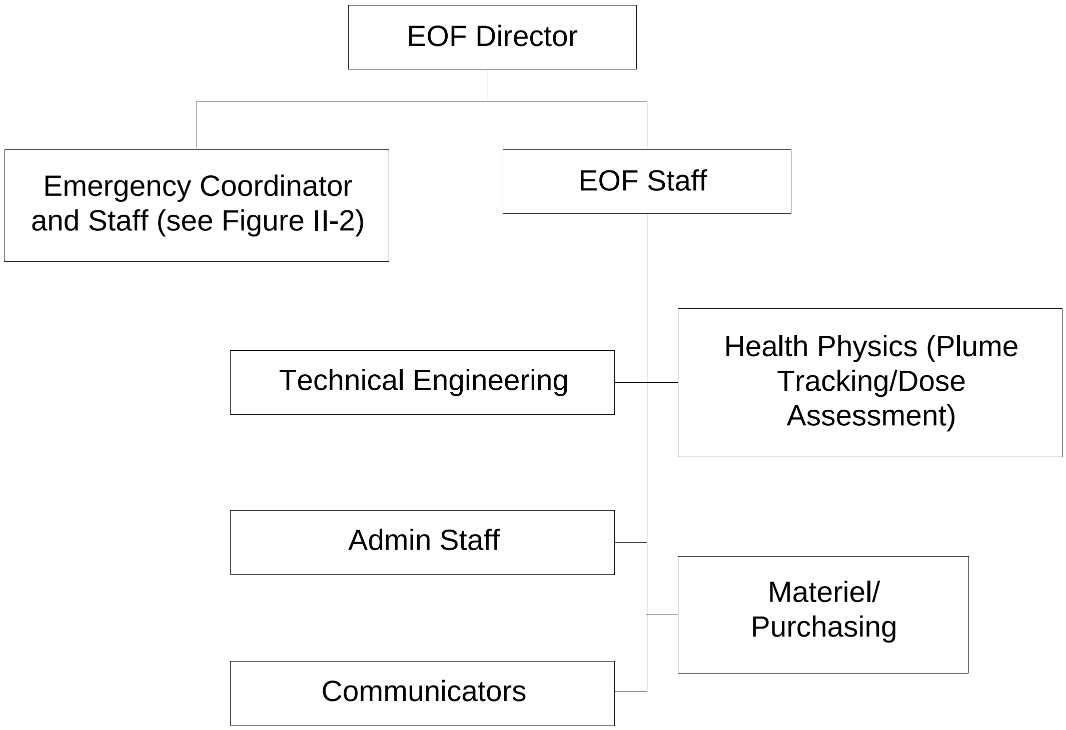


Table II-2 Plant Staff Emergency Functions

Major Functional Area	Major Tasks	Position, Title, or Expertise	On Shift[2,3]	Capability for Additions: Approx 45 min	Capability for Additions: Approx 60 min
Plant Operations and Assessment of Operational Aspects	Supervision of Station Operations and Assessment of Operational Aspects of Plant Operations	Shift Manager-(SRO)	1		
		Unit Supervisor (SRO)	1		
		Control Room Operator (RO)	2		
		Non-Licensed Operator	2		
Emergency Direction and Control (*Emergency Coordinator*)	Direction and Control of On-Site Emergency Activities	Shift Manager	1[1]		
Notification and Communication	Notify licensee, Commonwealth of Virginia, risk jurisdiction, and Federal personnel and maintain communication	Emergency Communicator	1[4]	1[4]	2[4]
Radiological Accident Assessment and Support of Operational Accident Assessment	EOF Director	Senior Manager			1
	Dose Assessment	Radiological Assessment Coordinator		1	
	Off-site surveys	HP Technicians		2[4]	2[4]
	On-site (out of plant)	HP Technicians		1[4]	1[4]
	In-plant surveys	HP Technicians	1	1	1
	Chemistry/Radiochemistry	Chemistry	1		1

Table II-2 Plant Staff Emergency Functions

Major Functional Area	Major Tasks	Position, Title, or Expertise	On Shift[2,3]	Capability for Additions: Approx 45 min	Capability for Additions: Approx 60 min
Plant System Engineering, Repair and Corrective Actions	Technical Support	Shift Technical Advisor function[5]	1		
		Technical Support Team Member (Core and Thermal Hydraulics)			1[6]
		Technical Support Team Member (Electrical)			1
		Technical Support Team Member (Mechanical)			1
	Repair and Corrective Actions	Damage Control Team Member (Mechanical Maintenance)	1[1]		2
		Damage Control Team Member (Electrical Maintenance)	1[1]	1	1
		Damage Control Team Member (Instrumentation and Control)		1	
Protective Actions (In-Plant)	Radiation Protection a. Access Control b. HP Coverage for repair, corrective actions, search and rescue, first aid, and firefighting c. Personnel monitoring d. Dosimetry	HP Technicians	2[1]	2[4]	2[4]
Firefighting	Firefighting	Fire Team Members	Per FSAR	Local Support	
Rescue Operations and First Aid	First Aid	First Aid Team Member	2[1, 4]	Local Support	

Table II-2 Plant Staff Emergency Functions

Major Functional Area	Major Tasks	Position, Title, or Expertise	On Shift[2,3]	Capability for Additions: Approx 45 min	Capability for Additions: Approx 60 min
Site Access Control and Personnel Accountability	Security, firefighting, communications, personnel accountability	Security Team Members	Staffing levels for the on-shift, initial additions and supplemental additions are provided in the Security Plan.		
		Security Team Leader			
Totals			**16**	**10**	**16**

1. This coverage is initially provided by personnel assigned other functions.
2. The minimum shift crew will be as defined in 10 CFR 50.54(m)(2)(i) and the Technical Specifications.
3. On-shift positions may be vacant for up to two hours due to unforeseen circumstances, such as sudden illness.
4. These resources are common between North Anna Units 1&2 and Unit 3 and may be shared.
5. These duties may be performed by an appropriately qualified SRO.
6. The Shift Technical Advisor function provides core thermal/hydraulics expertise prior to supplemental staff addition.

C. Emergency Response Support and Resources

The arrangements for emergency response support and resources described in SSAR Section 13.3.2.2.2.c are incorporated by reference.

1. Federal Response Capability

a. Under some complex circumstances it may be necessary to obtain offsite radiological monitoring support from Federal government agencies. The *Emergency Coordinator/EOF Director* may request FRMAC assistance through the NRC.

b. Federal radiological monitoring assistance may be provided by DOE-Oak Ridge under the DOE Radiological Assistance Program. Support available from DOE-Oak Ridge includes medical support from the Radiation Emergency Assistance Center/Training Site (REAC/TS). Dominion estimates that a FRMAC Advance Party could be expected at the site within 6 to 14 hours following the order to deploy, based on the availability of airports near the site.

   Dominion expects that NRC assistance from NRC's offices in Atlanta, GA, will arrive in the site vicinity within 7-8 hours following notification.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

c. Dominion provides facilities and resources needed to support the Federal response through the EOF. Available resources include office space and telephone and radio communications circuits. Dominion also provides limited office space and telephone communications facilities for NRC personnel in the TSC.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Offsite Organization Representation in the EOF

a. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Dominion does not expect risk jurisdiction representatives to be present at the EOF. A VDEM State On-Scene Coordinator (SOSC) serves as the Commonwealth's representative to provide interface between the utility and Commonwealth of Virginia and risk jurisdiction governments.

3. Radiological Laboratories

Radiological laboratories available to support emergency response efforts are available through the Commonwealth of Virginia to respond to an emergency at the NAPS site. These resources include those facilities listed below. Estimated travel times to the NAPS site are provided parenthetically.

- University of Virginia, Charlottesville, Virginia (45 minutes)
- Virginia Commonwealth Laboratories, Richmond, Virginia (75 minutes)
- Virginia Commonwealth University Medical Center, Richmond, Virginia (75 minutes)
- Newport News Shipbuilding & Drydock, Newport News, Virginia (3 1/2 hours)
- VDH Radiological Health Program Mobile Laboratory (1 hour)

North Anna maintains fixed laboratory equipment to support sampling analysis and monitoring. The equipment includes multichannel analyzers, proportional counters, a tritium analyzer, and whole body counters; arrangements are maintained for reading thermoluminescent dosimeters (TLDs).

The listed laboratory facilities are available to support emergency response activities on a 24-hour per day basis.

4. Other Supporting Organizations

Dominion has made arrangements to obtain additional emergency response support from the INPO Fixed Nuclear Facility Voluntary Assistance Agreement signatories and the Radiation Emergency Assistance Center/Training Site (REAC/TS). A certification letter in Appendix 7 outlines the scope of the expected support.

5. Not Used

6. Support During a Hostile Action Based Incident

Reserved for a future revision per schedule for implementing provisions of 10 CFR 50 Appendix E, Section IV.A.7.

D. Emergency Classification System

Dominion uses a standard emergency classification scheme, based on system and effluent parameters, which allows affected Commonwealth of Virginia and risk jurisdiction response organizations to determine initial offsite response measures.

The description of the emergency classification system in SSAR Section 13.3.2.2.2.d is incorporated by reference.

1. **Classification System**

10 CFR 50, Appendix E identifies four distinct classes of emergencies:

- Notification of Unusual Event (NOUE) - Events are in process or have occurred which indicate a potential degradation of the level of safety of the plant or indicate a security threat to facility protection has been initiated. No releases of radioactive material requiring off-site response or monitoring are expected unless further degradation of safety systems occurs.

  Potential degradation of the level of safety of the plant is indicated primarily by exceeding plant technical specification Limiting Condition of Operation (LCO) allowable action statement time for achieving required mode change. Precursors of more serious events should also be included because precursors do represent a potential degradation in the level of safety of the plant. Minor releases of radioactive materials are included. In this emergency class, however, releases do not require monitoring or offsite response.

  Actions undertaken at the NOUE emergency class include promptly informing State and local offsite authorities of the event, augmenting on-shift resources as needed, assessment and response, and escalation to a more severe class, if appropriate. If the emergency class is not escalated to a more severe class, then State and local offsite authorities will be notified of event termination in accordance with implementing procedures.

- Alert – Events are in process or have occurred which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involves probable life threatening risk to site personnel or damage to site equipment because of hostile action. Any releases are expected to be limited to small fractions of the EPA Protective Action Guideline (PAG) exposure levels.

  Rather than discussing the distinguishing features of “potential degradation” and “potential substantial degradation,” a comparative approach would be to determine whether increased monitoring of plant functions is warranted at the Alert level as a result of safety system degradation. This addresses the operations staff's need for help, independent of whether an actual decrease in plant safety is determined. This increased monitoring can then be used to better determine the actual plant safety state, whether escalation to a higher emergency class is warranted, or whether de-escalation or termination of the emergency class declaration is warranted. Dose consequences from these events are small fractions of the EPA PAG plume exposure levels.

  Actions undertaken at the Alert emergency class include those described for the NOUE emergency class and activation of the Technical Support Center and

Operational Support Center. In addition, Emergency Operations Facility and other key emergency personnel are alerted, on-site monitoring teams are dispatched, periodic plant status updates and meteorological assessments are provided to offsite authorities, as are dose estimates, if any event related releases are occurring.

- Site Area Emergency - Events are in process or have occurred which involve actual or likely major failures of plant functions needed for protection of the public or hostile actions that result in intentional damage or malicious act: 1) toward site personnel or equipment that could lead to the likely failure of or; 2) that prevent effective access to, equipment needed for the protection of the public. Any releases are not expected to result in exposure levels which exceed EPA Protective Action Guideline exposure levels beyond the site boundary.

  The discriminator (threshold) between Site Area Emergency and General Emergency is whether or not the EPA PAG plume exposure levels are expected to be exceeded outside the site boundary. This threshold, in addition to dynamic dose assessment considerations discussed in the EAL guidelines, clearly addresses NRC and offsite emergency response agency concerns as to timely declaration of a General Emergency.

  Actions undertaken at the Site Area Emergency emergency class include those described for the Alert emergency class and activation of the Emergency Operations Facility. In addition, an individual is dedicated to provide plant status updates to offsite authorities and periodic media briefings (jointly with offsite authorities when practicable), senior technical and management staff are made available for consultation with NRC and the Commonwealth of Virginia on a periodic basis, and release and dose projections based on available plant condition information and foreseeable contingencies are provided.

- General Emergency – Events are in process or have occurred which involve actual or imminent substantial core degradation or melting with potential for loss of containment integrity or hostile action that results in an actual los of physical control of the facility. Releases can be reasonably expected to exceed EPA Protective Action Guideline exposure levels offsite for more than the immediate site area.

  The bottom line for the General Emergency is whether evacuation or sheltering of the general public is indicated based on EPA PAGs, and therefore should be interpreted to include radionuclide release regardless of cause. In addition, it should address concerns as to uncertainties in systems or structures (e.g., containment) response, and also events such as waste gas tank releases and severe spent fuel pool events that may affect the public. To better assure timely notification, EALs in this category must primarily be expressed in terms of plant function status, with secondary reliance on dose projection. In terms of fission product barriers, loss of two barriers with loss or potential loss of the third barrier constitutes a General Emergency.

Actions undertaken at the General Emergency emergency class are identical to those described for the Site Area Emergency emergency class except there is no more severe emergency class.

Implementing procedures provide recognition categories, the associated initiating condition matrices, and the EALs.

2. Emergency Action Levels

The description of emergency action levels provided in SSAR Section 13.3.2.2.2.c is incorporated by reference. The following information supplements that description.

Implementing procedures provide the parameter values and equipment status that are indicative of each emergency class. Once indications are available to plant operators that an emergency action level has been exceeded, the event is promptly assessed and classified, and the corresponding emergency classification level is declared. This declaration occurs as soon as possible and within 15 minutes of when these indications become available.

3. Commonwealth/Risk Jurisdiction EAL Scheme

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Commonwealth/Risk Jurisdiction Emergency Action Procedures

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

E. Notification Methods and Procedures

Dominion maintains procedures for notification of Commonwealth of Virginia and risk jurisdiction response organizations and licensee emergency responders. These procedures include, or make reference to, the pre-planned content of messages to Commonwealth of Virginia and risk jurisdiction organizations. Dominion also makes arrangements to provide prompt notification to members of the public within the plume exposure pathway EPZ.

The descriptions of notification methods and procedures provided in SSAR Section 13.3.2.2.2.e are incorporated by reference.

1. Notification of Commonwealth and Risk Jurisdiction Authorities

Dominion maintains systems and procedures needed to provide prompt notification of affected Commonwealth of Virginia, risk jurisdiction, and Federal authorities following the declaration of any emergency condition, consistent with the emergency classification and action level scheme described in implementing procedures. The *Emergency Coordinator* initiates notification of affected Commonwealth of Virginia and risk jurisdiction authorities, including escalation or de-escalation of any emergency condition. State and local community officials will be notified within 15 minutes after declaration of an emergency (meaning the emergency classification level has been provided to the Virginia and risk-jurisdiction Emergency Operations Centers (EOCs)). The affected authorities include the Commonwealth of Virginia and the following risk jurisdictions:

- Caroline County
- Hanover County
- Louisa County
- Orange County
- Spotsylvania County

The primary notification method to be used is the Insta-phone system, which is accessible from the Control Room, TSC, and EOF. Back-up notification capability is maintained through the use of commercial telephone systems. Message content and verification methods are established in implementing procedures.

Dominion maintains systems and procedures needed to provide prompt notification of the USNRC Operations Center following the declaration of any emergency condition. The USNRC will be notified as soon as is practical following the notification of the Commonwealth of Virginia and risk jurisdiction authorities and within one (1) hour of the emergency declaration, including escalation or de-escalation of any emergency declaration. The primary notification method to be used is the Emergency Notification System, which is accessible from the Control Room, TSC, and EOF. Back-up notification capability is maintained through the use of commercial telephone systems.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Notification and Mobilization of Licensee Response Organizations

The description of the methods and procedures used for notifying and mobilizing the Dominion ERO provided in SSAR Section 13.3.2.2.2.e is incorporated by reference. The following information supplements that description.

The *Emergency Coordinator* directs the notification and mobilization of the licensee emergency response organization following the declaration of an Alert or higher level emergency. Although Dominion does not expect that the augmented resources of the emergency response organization would be required for a Notification of Unusual Event, all or part of the emergency response organization may be mobilized at the Notification of Unusual Event level at the discretion of the *Emergency Coordinator*.

When staffing of the ERO is required, or desired by the *Emergency Coordinator*, affected personnel may be notified by a multifaceted process, including alarms, announcements, pagers, telephones, on-line messages, etc. Notification and mobilization of the emergency response organization is initiated in accordance with implementing procedures.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. Message Content

The content of initial emergency notification messages from the plant to affected Commonwealth of Virginia and risk jurisdiction authorities includes information addressing the class of emergency, status of any radioactive releases, the locations of any potentially-affected populations, and recommendations regarding public protective actions.

The COVRERP provides the notification form used for notification of Commonwealth and risk jurisdiction authorities. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Follow-up Messages to Offsite Authorities

Follow-up messages from the plant to affected Commonwealth of Virginia and risk jurisdiction authorities include the following information, to the extent the information is available and appropriate, as mutually agreed upon between Dominion and VDEM:

- Incident date, time, and location;
- Name of and contact information for caller;
- Emergency classification;
- Information regarding any actual or potential radioactive releases, including medium, i.e., airborne, waterborne, surface spill, estimated duration/impact time, release point and elevation, chemical and physical form, and estimates of total and relative quantities and concentrations of noble gases, iodines, and particulates;
- Meteorological conditions, including wind speed and direction, stability class, and precipitation;
- Actual or projected exposure rates and projected integrated dose at the site boundary;
- Projected exposure rates and integrated doses at the projected peak location and at 2, 5, and 10 miles, including affected sectors;

- Estimates of surface contamination levels in the plant, onsite, and offsite;
- Emergency response actions underway;
- Recommended emergency actions, including protective action recommendations;
- Requests for any onsite support by offsite organizations (e.g., firefighting or medical transportation support); and
- Prognosis for changes in event classification or other conditions based on current assessments of plant conditions.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Disseminating Information to the Affected Public

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

6. Instructions to the Public in the Plume Exposure EPZ

The description of the methods and procedures used for providing instructions to members of the public provided in SSAR Section 13.3.2.2.2.e is incorporated by reference. The following information supplements that description.

The primary method of alerting the public is by sounding the Alert and Notification System sirens. Other alerting methods may include telephone communications, television and radio communications via the Emergency Alert System (EAS) stations, public address systems, bull horns from patrol cars, and personal contact.

The Commonwealth of Virginia and risk jurisdiction governments have ultimate responsibility for warning the public. Should it be necessary, Commonwealth of Virginia and risk jurisdiction authorities will alert the public within the plume exposure pathway EPZ using alternative methods described in the Virginia Emergency Operations Plan, Radiological Emergency Response Basic Plan and the risk jurisdiction Radiological Emergency Response Plans. Route alerting provides backup alert and notification capability (reference to 10 CFR 50, Appendix E, paragraph IV.D.4). Details of alternate methods are located in the same section of the respective plans as the primary methods. Members of the public within the plume exposure pathway EPZ shall be informed of what actions to take following activation of the Alert and Notification System. Upon hearing the alert, they are instructed to turn on their radios or television sets to the EAS to receive further instructions. The affected risk jurisdictions and the Commonwealth of Virginia have a 24 hour per day capability to activate the system. If the Commonwealth of Virginia cannot be contacted, the risk jurisdictions can contact the EAS control station directly in accordance with their respective plans.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

7. Written Messages to the Public

The description of the processes used for providing written messages to the public provided in SSAR Section 13.3.2.2.2.g is incorporated by reference. The following information supplements that description.

Affected Commonwealth of Virginia and risk jurisdiction officials bear responsibility for providing written emergency messages intended for the public, in particular providing instructions regarding specific protective actions. Dominion supports development of these messages by providing supporting information.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

F. Emergency Communications

Dominion maintains systems and procedures that provide for prompt communications between its ERFs and between the site and offsite ERFs. The descriptions of plans for implementing emergency communications provided in SSAR Section 13.3.2.2.2.f are incorporated by reference.

1. Description of Communication Links

Dominion maintains reliable communications links both within the plant and between the plant and external emergency response organizations. FSAR Section 9.5.2.2 and Section 9.5.2 of the ESBWR DCD provide a description of communications systems.

a. Dominion maintains capabilities for 24 hour per day emergency notification to the Commonwealth of Virginia and risk jurisdiction emergency response network. Commonwealth of Virginia/risk jurisdiction warning points are manned 24 hours per day. This communications link consists of an Insta-phone loop with links to risk jurisdictions and the Commonwealth of Virginia. If the Insta-phone is out of service, regular commercial telephone will be used to make the notifications and the above localities have a system to call back to the power station and verify the message.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Provisions for communicating with Commonwealth of Virginia and risk jurisdiction governments include an Insta-Phone loop that has been installed to permit simultaneous telephone-speaker communications from the Station to the risk jurisdictions and the Virginia EOC on a 24-hour per day basis. This loop can be activated from the Control Room, TSC, or EOF.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

c. Separate telephone lines are dedicated for communications with the NRC and include the following:

- Emergency Notification System (ENS): Provide for initial notifications, as well as ongoing information about plant systems, status and parameters, will be provided to the NRC. ENS lines are located in the Control Room, TSC and EOF.
- Management Counterpart Link (MCL): Provides for internal discussions between the NRC Executive Team Director/members and the NRC Director of Site Operations or licensee management. MCL lines are located in the TSC and EOF.
- Health Physics Network (HPN): Provide for communications regarding radiological and meteorological conditions, assessments, trends, and protective measures. HPN lines are located in the TSC and EOF.
- Reactor Safety Counterpart Link (RSCL): Allows for internal NRC discussions regarding plant and equipment conditions. RSCL lines are located in the TSC and EOF.
- Protective Measures Counterpart Link (PMCL): Allows for conduct of internal NRC discussions on radiological releases, meteorological conditions, and protective measures. PMCL lines are located in the TSC and EOF.
- Local Area Network (LAN) Access: Provides access to the NRC local area network. Jacks are provided in the TSC and EOF.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

d. Dominion provides capability for communications between the Control Room or TSC and the EOF, risk jurisdiction and Virginia EOCs via the Insta-Phone loop as described in Section II.F.1.b. Communications capabilities between the Control Room or TSC and radiological field personnel are also provided.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

e. Notification, alerting and activation of emergency response personnel in the TSC, OSC, and EOF are described in Section II.E.2.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

f. Dominion provides for communications between Control Room/TSC/EOF and the NRC Operations Center via dedicated telephone lines.

g. Dominion will activate the Emergency Response Data System (ERDS) within one hour of the declaration of an Alert or higher emergency classification in accordance with the applicable facility procedure(s).

2. Communication with Fixed and Mobile Medical Support Facilities

Dominion maintains communications systems that allow for communications between the site and fixed and mobile medical support facilities. The communications systems include both commercial telephone communications with fixed facilities and radio communications to the ambulance.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. Communication System Tests

Dominion conducts tests of its emergency communications system as follows:

- Communications with the facility and EOF and the Commonwealth of Virginia/risk jurisdiction warning points are tested monthly.
- Communications between the Virginia/risk jurisdiction EOCs and field assessment teams are tested annually.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

G. Public Education and Information

Dominion maintains a coordinated program to educate affected members of the public regarding emergency notification methods and actions. The descriptions of plans for implementing a public information program provided in SSAR Section 13.3.2.2.2.g are incorporated by reference.

1. Public Information Program

Dominion coordinates with affected Commonwealth of Virginia and risk jurisdiction authorities to disseminate pertinent emergency response information to members of the public in the plume exposure pathway EPZ on a yearly basis. Information may be provided via a number of methods. Distribution methods may include providing informational publications such as brochures or calendars through mailings to individual households in the plume exposure pathway EPZ. Emergency public information may also be distributed in telephone directories and utility bills, through public information postings, and information distributed via local media outlets. The distributed information includes:

- Educational information on radiation;
- Information regarding notification methods and immediate actions;
- Protective measures, such as information addressing evacuation routes, relocation centers, sheltering, respiratory protection, and radioprotective drugs;
- Information addressing special needs of the handicapped; and
- Point of contact for additional information.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Distribution and Maintenance of Public Information

Dominion coordinates with affected Commonwealth of Virginia and risk jurisdiction authorities to disseminate pertinent emergency response information to members of the public in the plume exposure pathway EPZ on a yearly basis. Written information applicable to permanent residences is provided in a form that is likely to be maintained in the residence (e.g., calendars, brochures) so it will be available during an emergency.

Information intended for transients (individuals on vacation in, camping in, or traveling through the plume exposure pathway EPZ) may include public postings, publications provided to hotels, motels, and campgrounds, and information published in telephone directories. These sources of information provide transients sources for local emergency information, such as local radio and television stations.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. News Media Coordination

a. The outlet for emergency information is the Joint Information Center. Dominion's *Chief Technical Spokesperson* will serve as the primary licensee spokesperson and media contact in the Joint Information Center. The *Chief Technical Spokesperson* gathers information from the ERO for dissemination to the news media and updates the news media on a periodic basis throughout any emergency situation during which the members of the media respond to the JIC.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Dominion provides a designated space for limited numbers of news media personnel within the EOF.

4. Information Exchange

a. The Dominion public affairs liaison has access to required public information, primarily through communications with the *Chief Technical Spokesperson* and designated members of the EOF staff.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. The Dominion public affairs liaison coordinates continuity and consistency of information with designated members of the Commonwealth of Virginia and risk jurisdiction emergency response organizations on a periodic basis.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

c. Rumor control is accomplished through ongoing contact with the *Chief Technical Spokesperson* and by the activities of a Dominion public affairs liaison in the JIC, who monitors communications, identifies rumors, and makes appropriate contacts to obtain and disseminate accurate information through the representatives in the JIC. The rumor control number is announced by the VDEM Public Affairs Office at media briefings and in press releases.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. News Media Training

News media training is accomplished through briefings for the news media offered on a yearly basis. These annual briefings acquaint members of the media organizations with the emergency plans, information regarding radiation hazards, and points of contact for release of public information during an emergency.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

H. Emergency Facilities and Equipment

The descriptions of ERFs in SSAR Section 13.3.2.2.2.h are incorporated by reference.

1. On-Site Emergency Response Facilities

The TSC and OSC are provided to support emergency operations consistent with the guidance provided in NUREG-0737, Supplement 1.

The function of the TSC is to provide an area and resources for use by personnel providing plant management and technical support to the plant operating staff during emergency evolutions. The TSC relieves the reactor operators of peripheral duties and communications not directly related to reactor system manipulations and prevents congestion in the Control Room.

The TSC is located in the electrical building. The ESBWR Design Certification Document provides pertinent design information (instrumentation, data system equipment, and power supplies) for the TSC in Tier 2.

Section II.B.5 provides a description of the TSC staff. Section II.O.4 provides a description of emergency response organization training and qualification.

The size of the TSC is sufficient to support a staff of 26 people.

The TSC is environmentally controlled to provide room air temperature, humidity and cleanliness appropriate for personnel and equipment. The room is provided with radiological protection and monitoring equipment necessary to monitor personnel radiation exposure and to maintain personnel doses less than 0.05 Sv (5 rem) total effective dose equivalent (TEDE), as defined in 10 CFR 50.2, for the duration of the accident. The level of protection is similar to the main control room. However, in the event that off-site and on-site AC power were unavailable, the TSC could be evacuated and the TSC management function transferred to a location unaffected by the radiation release.

The TSC is provided with reliable voice and data communication with the main control room and EOF and reliable voice communications with the OSC, NRC Operations Center and Virginia and risk jurisdiction EOCs. Control room data communication of emergency response data system (ERDS) data with the NRC Operations Center is also provided as appropriate. Section II.F provides a description of the communications capabilities provided in the TSC.

Display capability of the technical data system in the TSC includes a workstation that, at minimum, is capable of displaying the parameters that are required of a Safety Parameter Display System (SPDS). The SPDS function is described in DCD Section 18.8 through its incorporated references.

Key reference materials are available to the TSC staff via Local Area Network connection from the Nuclear Electronic Document Library, including:

- Up-to-date, as-built drawings, schematics, and diagrams showing conditions and locations of plant structures and systems down to component level
- Plant technical specifications
- Plant operating procedures
- Emergency operating procedures
- Final Safety Analysis Report

- Up-to-date records related to licensee, State, and local emergency response plans
- Offsite population distribution data
- Evacuation plans

Section II.H.9 provides a description of the OSC.

2. Emergency Operations Facility

The function of the EOF is to provide a location for Dominion management to direct and coordinate emergency response activities, with emphases on providing support to the plant staff and coordinating emergency response activities with offsite response agencies.

The Local EOF and Central EOF are the same as those used for NAPS Units 1 and 2. The Local EOF is located within the owner-controlled area, adjacent to the NAPS Units 1 and 2 Training Facility, and the Central EOF at Dominion's Innsbrook Technical Center in Glen Allen, Virginia, approximately 30 miles from Unit 3. This configuration does not alter the functions of the EOF as described in NUREG-0696.

Provisions are made for staffing of the EOF by Dominion, Commonwealth of Virginia, and NRC personnel. Dominion also makes provisions for accommodating a limited number of media personnel in the EOF. Section II.B.5 provides a description of the Dominion EOF staff. Section II.N.2 provides a description of EOF drills. Section II.O.4 provides a description of emergency response organization training and qualification.

The size of the EOF is sufficient to support 35 people. The Local EOF was designed to provide a specified protection factor from gamma radiation. The Local EOF also has a specially designed ventilation system to limit the exposure of its occupants and further assure its availability during an emergency. Provisions exist for dedicated radiation monitoring equipment to measure airborne particulate and direct radiation. The location of the Central EOF precludes the necessity of providing radiation monitoring systems.

Section II.F provides a description of the communications capabilities provided in the EOF.

The Local EOF and Central EOF draw power from commercial power sources. There is electrical generator backup power to the Central EOF. A loss of commercial power should not impact any of the voice or data communications equipment located in the Central EOF. Common Dominion telecommunications infrastructure that supports EOF functions, including, but not limited to, fiber optic transmission equipment, telephone switching equipment and data network routers, is configured to operate from at least one and usually multiple backup power sources in the event of a loss of commercial power. These backup sources include generator, DC battery and UPS systems.

Display capability of the technical data system in the EOF includes a workstation that, at minimum, is capable of displaying the parameters that are required of an SPDS. The SPDS function is described in DCD Section 18.8 through its incorporated references.

Key reference materials will be available to the EOF staff via Local Area Network connection from the Nuclear Electronic Document Library, including:

- Plant technical specifications
- Plant operating procedures
- Emergency operating procedures
- Final Safety Analysis Report
- Up-to-date records related to licensee, State, and local emergency response plans
- Offset population distribution data
- Evacuation plans
- Up-to-date, as-built drawings, schematics, and diagrams showing conditions and locations of plant structures and systems down to component level

3. Commonwealth/Risk Jurisdiction Emergency Operations Centers

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Activation and Staffing of Emergency Response Facilities

Dominion staffs and activates the designated ERFs as follows[6]:

- Notification of Unusual Event – ERF staffing not normally needed, but may be undertaken at the discretion of the *Emergency Coordinator*.
- Alert, Site Area Emergency and General Emergency – Staffing of the TSC and OSC required.
- Site Area Emergency and General Emergency – Staffing of the EOF required.

Following declaration of an emergency condition, the ERFs are staffed and activated in accordance with EPIPs. The descriptions of ERF notification and staffing provided in SSAR Sections 13.3.2.2.2.e.2 and 13.3.2.2.2.f.4 are incorporated by reference.

In the event the site is under threat of, or experiencing hostile action, the Louisa Fire Training Center functions as a staging area for augmentation of emergency response staff. This location has the capability to communicate with the EOF, control room, and plant security.

6. See Section II.A.1.a of this plan regarding situations under which staffing of the emergency response facilities may be deferred.

Commonwealth of Virginia and risk jurisdiction emergency response personnel also staff their ERFs consistent with the provisions of their respective plans.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Onsite Monitoring Systems

Dominion maintains and operates onsite monitoring systems needed to provide data that is essential for initiating emergency measures and performing accident assessment. This includes monitoring systems for geophysical phenomena, radiological conditions, plant processes, and fire hazards.

a. Section 3.7.4 of the FSAR and the DCD provide a description of the seismic monitoring system.

b. Section 12.3 of the FSAR and the DCD provide a description of the installed radiological monitoring systems. In addition to the installed systems, Dominion maintains an adequate supply of portable radiation monitoring and sampling equipment, including dedicated emergency response equipment, consistent with Sections II.H.7, II.H.10, and II.H.11 and Appendix 6.

c. Section 11.5 of the FSAR and the DCD provide description of the plant process monitoring systems.

d. Section 9.5.1 of the FSAR and the DCD provide a description of the plant fire monitoring system.

6. Access to Data from Monitoring Systems

a. Dominion acquires meteorological data from the National Weather Service (NWS) during periods when the primary system is unavailable. Back-up seismic data is available from the U.S. Geological Survey (National Earthquake Information Center) and the Virginia Polytechnic Institute and State University (Virginia Tech) Seismological Observatory. Streamflow data is available from the U.S. Geological Survey. Flooding data is available from NOAA's Hydro-Meteorological Reports. Other data sources, such as commercial media outlets, may also be used.

b. Offsite environmental radiological monitoring equipment includes a series of continuous air samplers and environmental monitoring dosimeters surrounding the facility. The facility's Offsite Dose Calculation Manual (ODCM) describes the monitoring systems. In addition to the monitoring systems, equipment, and radiological laboratory facilities provided at the plant, Dominion maintains arrangements to obtain back-up radiological monitoring and analysis support from offsite organizations. Section II.A provides a description of these arrangements and the capabilities of the affected organizations and facilities. Appendix 7 provides pertinent certifications from these support organizations.

c. Section II.C.3 provides a description of the available laboratory facilities.

7. Offsite Radiological Monitoring Equipment

Dominion provides offsite radiological monitoring equipment suitable for assessment of the offsite radiological consequences of facility incidents, for use by its offsite monitoring field teams. Appendix 6 provides a description of the types of radiological monitoring equipment provided for field team use.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

8. Meteorological Instrumentation and Procedures

The station's Meteorological Monitoring System provides the capability for providing data that are used for predicting atmospheric effluent transport and diffusion. The system consists of a primary and a backup tower, the locations of which were chosen so as to be representative of regional conditions.

The parameters monitored by the site's primary meteorological tower are listed below.

10 Meter Elevation:

- Wind speed
- wind direction
- horizontal wind direction fluctuation
- temperature (used with 48.4 meter data for differential temperature)
- dew point temperature

48.4 Meter Elevation:

- Wind speed
- wind direction
- horizontal wind direction fluctuation
- temperature (used with 10 meter data for differential temperature)

Precipitation is monitored at the ground level.

The NAPS backup meteorological monitoring site consists of instrumentation on a freestanding 10 meter tower. This tower is located approximately 1300 feet northeast of the Unit 1 containment building and serves as the backup meteorological monitoring site.

A sensor at the top of the mast monitors wind speed, wind direction, and horizontal wind direction fluctuation. SSAR Section 2.3 provides a detailed description of the Meteorological Monitoring System.

9. Operational Support Center

The function of the OSC is to provide a common area and the necessary supporting resources for the assembly of designated operations support personnel during emergency conditions. Designated plant support personnel, as indicated in Section II.B, assemble in the OSC to provide support to both the Control Room and TSC. Personnel reporting to the OSC can be assigned duties in support of emergency operations. Assessment, corrective action, and rescue personnel are dispatched by the OSC to locations in the plant, as directed by the TSC and Control Room.

The OSC is not designed to remain habitable under all projected emergency conditions; however, implementing procedures make provisions for relocating the OSC as needed, based on ongoing assessments of plant conditions and facility habitability.

The OSC is located within the Protected Area in the Service Building. The OSC provides dedicated telephone extensions for communicating with the Control Room and the TSC. This permits personnel reporting to the OSC to be assigned to duties in support of emergency operations. The OSC is also equipped with a separate telephone line to provide for communications with on-site and off-site locations, as needed. Section II.F provides a description of the communications capabilities provided in the OSC.

10. Emergency Equipment and Supplies

Dominion performs inspection, inventory, and appropriate operational tests of dedicated emergency equipment and instruments on a quarterly basis consistent with Section II.P. Plant procedures establish requirements for performing inventories and operational tests. Dominion maintains sufficient reserves of equipment and instruments to replace any items that are removed from the emergency kits for calibration or repair.

Appendix 6 provides a description of the emergency equipment and supplies to be provided.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

11. Emergency Kits

Appendix 6 provides a description of the emergency equipment and supplies typically provided for use by emergency response personnel.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

12. Receipt of Field Monitoring Data

Health Physics personnel located in the EOF are designated as the point of contact for the receipt of off-site monitoring data results and sample media analysis results collected by Dominion personnel.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

I. Accident Assessment

The descriptions of provisions for accident assessment provided in SSAR Section 13.3.2.2.2.i are incorporated by reference.

1. Parameters Indicative of Emergency Conditions

Implementing procedures describe plant system and effluent parameter values that are indicative of off-normal conditions and the various indications that correspond to the emergency initiating conditions. Plant procedures specify the types and capabilities of the instruments used to indicate emergency conditions.

2. Plant Monitoring Systems

Section 7.5.1 of the ESBWR Design Control Document describes the Post-Accident Monitoring Systems and is incorporated into this plan by reference.

3. Determination of Source Term and Radiological Conditions

a. Appendix 2 and plant procedures provide means for relating various measured parameters, including containment radiation monitor reading, to the source term available for release within plant systems.

b. Appendix 2 and plant procedures provide means for relating various measured parameters, including effluent monitor readings, to the magnitude of the release of radioactive materials.

4. Relationship Between Effluent Monitor Reading and Exposure and Contamination Levels

Dose assessment procedures include the relationship between effluent monitor readings and onsite and offsite exposures and contamination for various meteorological conditions. Appendix 2 provides a description of the emergency dose assessment program used at NAPS. Information includes dose and dose rate determinations based on plant effluent monitors, and contamination estimates based on deposition assumptions and meteorological conditions.

5. Meteorological Information

Section II.H.8 and Appendix 2 provides a description of the meteorological monitoring systems that are used to provide initial values and continuing assessment of meteorological conditions under emergency conditions.

6. Determination of Release Rates and Projected Doses When Installed Instruments Are Inoperable or Off-Scale

Plant procedures establish processes for estimating release rates and projected doses if the associated instrumentation is inoperable or off-scale. These procedures include the following considerations:

- Estimated releases based on field monitoring data
- Surrogate instrumentation and methods to estimate extent of fuel damage.

Appendix 2 provides a description of the emergency dose assessment program used at NAPS. Information includes dose and dose rate determinations based on plant effluent monitors, and contamination estimates based on deposition assumptions and meteorological conditions.

7. Field Monitoring Capability

Dominion provides emergency response field teams composed of one or more radiation protection technicians trained in accordance with the emergency preparedness training requirements established in Section II.O of this plan. SSAR Section 13.3.2.2.2.i discusses field team activities and is incorporated by reference.

Appendix 6 provides a description of the instrumentation that is available for performance of field monitoring in the plume exposure pathway EPZ. In addition to the required instrumentation, Dominion provides protective equipment (including respiratory protection and radioprotective drugs), communications equipment, and supplies to facilitate performance of radiation, surface contamination, and airborne radioactivity monitoring. Implementing procedures provide guidance for field monitoring teams' performance of monitoring activities. Field monitoring teams act under the direction of Health Physics personnel in the TSC prior to activation of the EOF and, following activation of the EOF, under the direction of Health Physics personnel in that facility.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

8. Assessing Hazards Through Liquid or Gaseous Release Pathways

Dominion trains, designates, equips, dispatches, and coordinates field teams consistent with Section II.I.7. The field teams perform sampling of offsite media as needed to assess the actual or potential magnitude and locations of radiological hazards. Dominion notifies and activates field team personnel consistent with Section II.E. Mobilization times are consistent with Section II.B.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

9. Measuring Radioiodine Concentrations

Dominion equips field teams with portable air samplers, appropriate filters or other sampling media (e.g., silver zeolite or other media capable of collecting airborne radioiodine samples), and analysis equipment capable of detecting radioiodine concentrations at or below 10^{-7} microcuries per milliliter under field conditions, taking into consideration potential interference from noble gas activity and background radiation. Appendix 6 provides information regarding emergency supplies, equipment, and instruments.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

10. Relating Measured Parameters to Dose Rates

Plant implementing procedures establish the means for relating measured parameters, such as surface, airborne, or waterborne activity levels, to dose rates for those key isotopes listed in Table 3 of NUREG-0654. Implementing procedures also establish provisions for estimating the projected dose based on projected and actual dose rates. Health Physics personnel are responsible for directing implementation of these procedures under emergency conditions.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

11. Tracking of Plume Using Federal and Commonwealth Resources

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

J. Protective Response

The descriptions of protective response measures provided in SSAR Section 13.3.2.2.2.j are incorporated by reference.

1. On-Site Notification

Dominion establishes and implements methods to inform personnel within the protected area (within the Security fence) and exclusion area (within 5000 feet of the Unit 3 containment) of an emergency condition requiring individual action.

Dominion informs individuals located within the protected area primarily via use of the plant public announcement system and audible warning systems. In high noise areas or other areas where these systems may not be audible, other measures, such as visible warning signals or personal notifications, may be used.

Dominion informs individuals located within the exclusion area, but outside of the protected area, via audible warnings provided by warning systems and the activities of the Security Force (e.g., vehicle-mounted public address systems) and activities of the Virginia Department of Game and Inland Fisheries. Dominion provides information regarding the meaning of the various warning systems, and the appropriate response actions, via plant training programs, visitor orientation, escort instructions, posted instructions, or within the content of audible messages.

Dominion maintains the ability to notify individuals within the Protected Area within about 15 minutes of the declaration of any emergency requiring individual response actions, such as accountability or evacuation.

2. Evacuation Routes and Transportation

Dominion has established evacuation routes to assembly areas consistent with Figure II-4. If the evacuation routes are rendered impassable, such as due to radiological or meteorological conditions, then provisions will be made to retain affected personnel on site.

Affected individuals evacuate the site via personal vehicles. If any individual on site does not have access to a personal vehicle, the affected individual will evacuate with another evacuating individual. Dominion directs evacuees to a designated assembly area.

Dominion informs individuals of the evacuation routes and appropriate instructions via plant training programs, visitor orientation, escort instructions, posted instructions, or within the content of audible messages.

Should site evacuation via either designated evacuation route be determined to be inadvisable due to adverse conditions (e.g., weather-related, radiological, or traffic density conditions), Dominion will direct affected individuals to a safe onsite area (as determined by the *Emergency Coordinator* or designee) for accountability and, if necessary, contamination monitoring and decontamination.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. Personnel Monitoring and Decontamination

Dominion has established the primary and secondary assembly areas to provide a location for personnel monitoring. The *Emergency Coordinator* directs contamination monitoring of personnel, vehicles, and personal property arriving at the assembly area when there is a likelihood that individuals and their property may have become contaminated before or during the site evacuation.

4. Non-Essential Personnel Evacuation and Decontamination

In the event of a Site Area Emergency or General Emergency, Dominion may evacuate non-essential personnel (i.e., personnel who do not have an emergency response assignment) consistent with the provisions of Section II.J.2. Appropriate equipment and supplies are provided from the facility to the assembly areas to facilitate contamination monitoring.

5. Personnel Accountability

Dominion provides the capability to account for individuals within the Protected Area and to identify any missing individuals within 30 minutes following initiation of assembly and accountability measures. Dominion also provides a capability to account for individuals within the protected area continuously after the initial accountability. Dominion maintains these capabilities consistent with the requirements of the facility Security Plan.

6. Protective Measures

Dominion provides equipment and supplies to provide adequate protection for individuals remaining or arriving onsite during an emergency. The equipment and supplies include:

a. respiratory protection equipment;

b. protective clothing; and

c. radioprotective drugs.

Onsite supplies of protective clothing and respiratory protection equipment may be augmented by that provided by offsite responders, such as firefighters responding to the site.

In the event of a hostile attack against the site, conditions may dictate initiation of protective measures other than personnel assembly, accountability and evacuation. The *Emergency Coordinator* makes decisions regarding appropriate protective measures based on evaluation of site conditions, including input from the Security force. If, based on the judgment of the *Emergency Coordinator*, personnel assembly, accountability, and evacuation may result in undue hazards to site personnel, the *Emergency Coordinator* may direct other protective measures, including:

- Evacuation of personnel from areas and buildings perceived as high-value targets
- Site evacuation by opening, while continuing to defend, security gates
- Dispersal of key personnel
- On-site sheltering
- Staging of ERO personnel in alternate locations pending restoration of safe conditions

- Implementation of accountability measures following restoration of safe conditions

Appendix 6 provides a description of the emergency response supplies and equipment to be provided.

7. **Protective Action Recommendations and Bases**

Public Protective Action Recommendations (PARs) are based on plant conditions, estimated offsite doses, or some combination of both. Dominion provides Protective Action Recommendations promptly to the Virginia EOC. EALs correspond to the projected dose to the population at risk and are determined consistent with the methodology described in implementing procedures.

If the *Emergency Coordinator* declares a General Emergency, then Dominion will communicate to the Virginia EOC a PAR to evacuate at least a two mile radius around the facility, unless impediments to evacuation exist. The PAR may call for other areas within the plume exposure pathway EPZ to evacuate, shelter-in-place, or monitor and prepare to take protective actions as directed.

In addition to the EAL-based PAR, Dominion provides PARs based on offsite dose projections. The Health Physics staff is responsible for conducting offsite dose projections periodically throughout any emergency during which there is an actual or potential release of an amount of radioactive material that is likely to result in offsite consequences. Implementing procedures will establish requirements for performing required calculations and projections.

The projected doses are compared to the Protective Action Guides shown in Table II-3, as derived from EPA 400-R-92-001, “Manual of Protective Action Guides and Protective Actions for Nuclear Incidents,” (Reference 15) and Protective Action Recommendations are developed based on the results of these comparisons as discussed in Section II.J.10.m. Consideration will be given to evacuation, sheltering, and as a supplement to these, the prophylactic use of potassium iodide (KI), as appropriate.

Prior to activation of the EOF, the *Emergency Coordinator* is responsible for determining PARs and communicating the PARs to the Virginia EOC. Following activation of the EOF, *EOF Director* assumes these responsibilities. The *Emergency Coordinator* or *EOF Director* provides PAR to the Virginia EOC, which is responsible for implementing the protective actions, using the communications systems discussed in Section II.H of this plan or by direct communications in the EOF.

Table II-3 Protective Action Guides

Projected Dose		
Total Effective Dose Equivalent (TEDE)	**Committed Dose Equivalent Thyroid (CDE Thyroid)**	**Protective Action Recommendation**
< 1 rem	< 5 rem	No protective action required based on projected dose
≥1 rem	≥5 rem	Evacuate affected zones and shelter the remainder of the plume exposure pathway EPZ

8. Evacuation Time Estimates

Evacuation time estimates (ETEs) are developed within 365 days of when U.S. Census Bureau decennial data becomes available. ETEs are a factor considered in the development of off-site protective action recommendations (see Section II.J.7) and are provided to Commonwealth and local governmental authorities for use in developing off-site protective action strategies.

Dominion conducted an ETE (Reference 16) in 2008, that was consistent with the guidance provided in Appendix 4 of NUREG-0654 and NUREG/CR-6863, "Development of Evacuation Time Estimate Studies for Nuclear Power Plants" (Reference 17). The ETE updated the information in SSAR Section 13.3.2.1.

Dominion updated the ETE report (Reference 20) in November 2012 to be consistent with NUREG/CR-7002, "Criteria for Development of Evacuation Time Estimate Studies" (Reference 21). The updated population distribution and ETEs are summarized in Appendix 4.

The ETE report, and its 2012 update, have not revealed the existence of any significant impediments to the development of emergency plans.

9. Implementation of Protective Measures

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

10. Protective Measures Implementation

a. Radiological monitoring locations are shown in Figure II-5. Evacuation routes, evacuation areas, and locations of assembly areas are presented in Figure 10-1 and Figure 10-2 of the ETE report.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Appendix 4 provides maps of the plume exposure pathway EPZ illustrating population distribution around the facility by evacuation area and in a sector format.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

c. Warnings to the public within the plume exposure pathway EPZ are the responsibility of Commonwealth of Virginia and risk jurisdiction officials. The primary method of warning the public is by the use of the Early Warning System sirens. Other warning methods may include telephone communications, television and radio Emergency Alert System stations, public address systems, bull horns from patrol cars and personal contact. There are currently no hospitals, prisons, or nursing homes within the plume exposure pathway EPZ.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

d. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

e. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

f. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

g. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

h. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

i. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

j. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

k. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

l. This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

m. Specific protective action recommendations, based on NUREG-0654, Supplement 3 (Reference 18) and on plant and meteorological conditions, are included in an implementing procedure.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

11. Protective Measures Specified by the Commonwealth

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

12. Registering and Monitoring Evacuees

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

Figure II-4 Map to North Anna Remote Assembly Areas

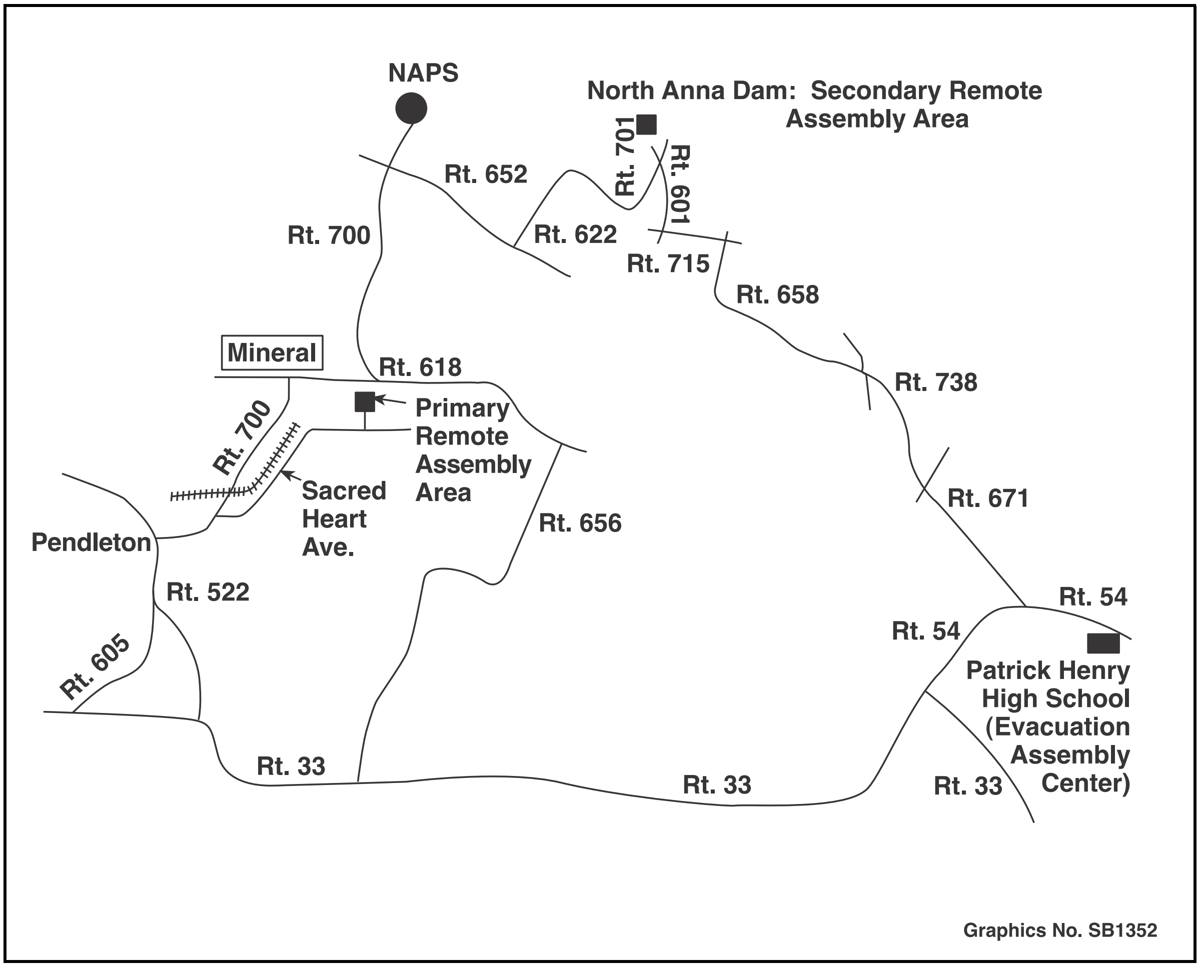
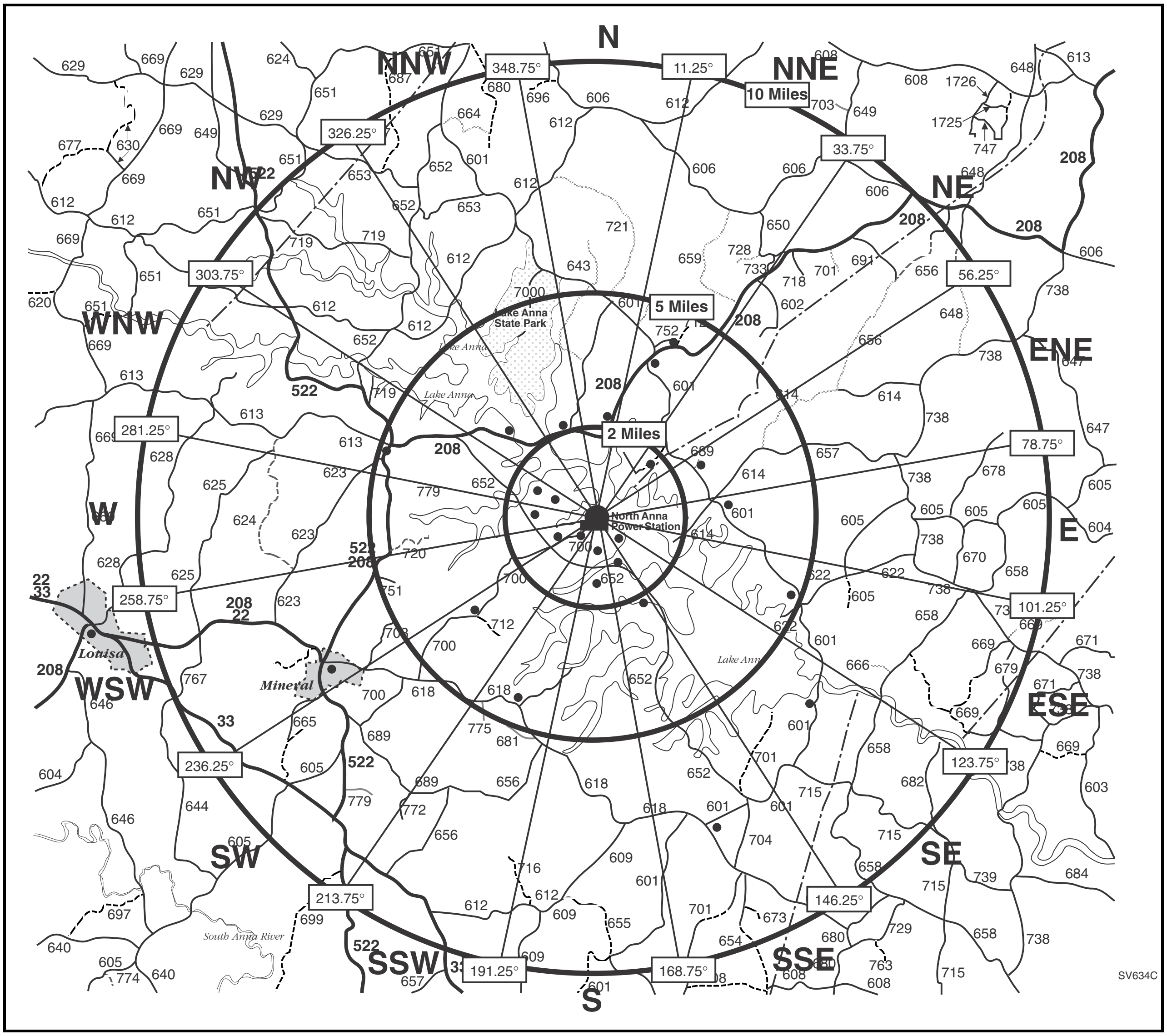


Figure II-5 Radiological Monitoring Locations



• Indicates radiological monitoring location

K. Radiological Exposure Control

The descriptions of radiological exposure control measures in SSAR Section 13.3.2.2.2.k are incorporated by reference.

1. On-Site Exposure Guidelines and Authorizations

Dominion implements onsite exposure guidelines for emergency response personnel consistent with those published in EPA 400-R-92-001, Table 2-2, “Guidance on Dose Limits for Workers Performing Emergency Services.” The applicable guidelines are provided in Table II-4.

Prior to activation of the EOF, the *Emergency Coordinator*, in consultation with facility Health Physics personnel, is responsible for authorization of any emergency exposures resulting in doses exceeding the numerical values of the occupational dose limits provided in 10 CFR Part 20. Following activation of the EOF, the *EOF Director*, in consultation with Health Physics personnel and the *Emergency Coordinator*, authorizes any exposures in excess of the numerical values of the occupational dose limits provided in 10 CFR Part 20. If exposures in excess of the numerical values of the occupational dose limits provided in 10 CFR Part 20 are required, these exposures will be limited to individuals who are properly trained and knowledgeable of the tasks to be completed and the risks associated with the exposures. Selection criteria for volunteer emergency workers include consideration of those who are in good physical health, are familiar with the consequences of emergency exposure, and are not a declared pregnant worker. It is preferable, though not mandatory, that volunteers be older than 45 years of age and not be a female capable of reproduction. Efforts are made to maintain personnel doses ALARA.

Table II-4 Emergency Worker Exposure Guidelines

	Dose Guideline in rem		
Activity	**TEDE**	**Lens of the Eye**	**Other Organs**
Any activity other than those specifically authorized below	5	15	50
Protecting Valuable Property	10	30	100
Lifesaving or Protection of Large Populations	25	75	250
Lifesaving or Protection of Large Populations[Note 1]	>25	>75	>250

Note 1: This guideline applies only to volunteers who are fully aware of the risks involved.

2. Radiation Protection Program

Chapter 12 of the FSAR describes a radiation protection program (RPP) consistent with the requirements of 10 CFR Part 20. The RPP, in concert with the EPIPs, to be developed prior to loading of nuclear fuel, includes provisions for implementing emergency exposure guidelines. Implementing procedures establish procedures for allowing onsite volunteers to receive radiation doses in the course of carrying out life-saving and other emergency response activities, including provisions for expeditious decision-making and consideration of the relative risks.

3. Dosimetry and Dose Assessment

a. Dominion maintains a site personnel radiation dosimetry program that includes the capability to determine both external and internal doses consistent with the requirements of 10 CFR Part 20. The external dosimetry program includes provisions and requirements for use of both permanent record and self-reading dosimeters (e.g., pocket or electronic dosimeters). Dosimeter ranges are sufficient to measure both planned routine and foreseeable accident photon doses. Plant procedures associated with this plan establish requirements for distributing dosimeters to emergency responders, including those individuals responding to the site from offsite locations. Internal doses are typically estimated through the use of whole body counting and/or in-vitro sampling and analysis routines. Plant procedures associated with this plan or the RPP establish requirements for determining internal doses based on in-vivo or in-vitro analyses results or by assessment of individual exposures to airborne radioactive materials.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Implementing procedures also establish guidance for wearers to periodically read their self-reading dosimeters to monitor compliance with emergency exposure guidelines. Dominion maintains individual dose records in accordance with the requirements of 10 CFR Part 20 and the RPP and its supporting procedures.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Commonwealth of Virginia and Risk Jurisdiction Responder Exposure Authorizations

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Decontamination Action Levels

a. Dominion implements requirements for personnel and area decontamination, including decontamination action levels and criteria for returning areas and items to normal use, in procedures supporting the RPP.

   Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Dominion implements procedures for decontamination of onsite emergency personnel wounds, supplies, instruments and equipment, and for waste disposal. Dominion provides decontamination supplies with emergency kits consistent with Appendix 6.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

6. Contamination Control Measures

a. The FSAR and Security Plan establish requirements for site access control from offsite locations. Following a site evacuation, law enforcement agencies control access to the owner-controlled area consistent with the requirements of the supporting Commonwealth of Virginia and risk jurisdiction plans. The site Security Force controls entry to the restricted area by individuals, including emergency responders, who must enter the site during an emergency. The RPP and its supporting procedures establish requirements for limiting access to areas having significant radiological hazards, consistent with the requirements of 10 CFR Part 20 and Chapter 12 of the FSAR.

b. Should the potential exist for contamination of onsite food or drinking water supplies that renders these supplies non-consumable, arrangements will be made for transport of non-contaminated offsite supplies to the site.

c. Dominion permits areas and items to be returned to normal (i.e., non-contaminated) use following conduct of appropriate surveys and verification that the contamination levels meet the criteria provided in the RPP or its supporting procedures.

7. Decontamination of Relocated Site Personnel

Dominion makes provisions for protective clothing, contamination monitoring, and decontamination, including decontamination of radioiodine contamination on the skin, at the offsite assembly area or other location as directed. Appendix 6 provides a description of the emergency equipment and supplies to be provided.

L. Medical and Public Health Support

The descriptions of plans for medical and public health support in SSAR Section 13.3.2.2.2.I are incorporated by reference.

1. Hospital and Medical Support

Dominion has established a certification letter with the Virginia Commonwealth University Medical Center (VCUMC) under which VCUMC will provide medical services for injured personnel from Unit 3. VCUMC has established a specialized area of the hospital for treatment with appropriate Health Physics functions, and implements a coded system to alert hospital team members. Radiation monitoring equipment, dosimeters, and protective clothing are available at VCUMC.

VCUMC established and maintains the capability to evaluate the radiation exposure and/or uptake of accident victims and to handle contaminated victims. These capabilities are established and maintained through training courses consistent with Section II.O, periodic drills and exercises consistent with Section II.N, and services provided consistent with agreements between Dominion and the medical support providers.

In the event that a contaminated injured person is transported from Unit 3 to an offsite medical facility, Dominion may provide to the facility one or more technicians qualified to perform radiological monitoring if requested by the facility to support the radiological aspects of the medical treatment and post-treatment efforts.

Appendix 7 provides a copy of the relevant certification letter.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. On-Site First Aid Capability

Dominion maintains a trained First Aid Team at the site to provide 24 hour per day first aid support consistent with Section II.B. Dominion maintains First Aid Team readiness through training consistent with Section II.O and drills and exercises consistent with Section II.N.

3. Emergency Medical Facilities Within the Commonwealth

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

4. Medical Emergency Transportation

Contaminated injured personnel will be suitably clothed or prepared to prevent the spread of contamination in the transporting vehicle, if practical considering the medical condition of the injured person. Communication can be maintained with VCUMC from the station. The Station can also communicate with the site ambulance, if used, by use of an ultra-high frequency (UHF) radio, and the ambulance can communicate with VCUMC by way of the Hospital Emergency Alerting Radio (HEAR) system. In addition, arrangements have been made with local volunteer rescue squads to transport injured contaminated personnel to VCUMC. Response team members have received training concerning transportation of contaminated injured individuals. A Health Physics technician, with appropriate instrumentation, would normally accompany contaminated injured personnel to VCUMC. The approximate time to transport a patient to VCUMC is

75 minutes. The estimated time for local rescue squads to arrive at the station is 30 minutes.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

M. Recovery and Re-Entry

1. Recovery Plans and Procedures

Dominion implements recovery plans and procedures that provide guidance for a range of recovery and re-entry activities, including:

- Recovery/re-entry organization;
- Responsibilities for recovery/re-entry decision-making, including decisions for relaxing protective measures based on existing and potential hazardous conditions;
- Means for informing members of the emergency response organization that recovery operations are to be initiated and related changes in the organizational structure; and
- Methods for periodically updating estimates of total population exposure.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Recovery Organization

Under some circumstances, particularly those involving significant damage to the facility or offsite consequences, there may be a need for ongoing assessment and recovery actions following the cessation of emergency response activities. Prior to entering the recovery/re-entry phase of operations following an emergency, Dominion establishes a recovery organization consistent with the existing conditions and continuing organizational needs.

The recovery organization includes those management, technical, and administrative personnel necessary to provide for timely and effective recovery of the facility based on assessments of plant conditions and desired end states. The recovery process is further outlined in the EPIP specifically designed for administration of the recovery program. The basic organization may be modified, as required, to address the needs of the given situation. The *EOF Director* assumes control and direction of the recovery operation with the authority and responsibilities set forth in the EPIPs.

The recovery organization develops plans and procedures designed to address both immediate and long term actions. The necessity to maintain protective measures implemented during the emergency will be evaluated and, if deemed appropriate, the recovery organization will recommend relaxation of the protective measures. Because it is not possible to foresee all of the consequences of an event, specific recovery procedures may need to be written to address specialized requirements. Where possible, existing station procedures are utilized. Any special recovery procedures require the same review and approval process accorded other station procedures.

Depending on plant conditions and the scope of required activities, the recovery organization may discharge its activities from one or more designated ERFs or from other locations as specified by the responsible recovery organization managers. As recovery operations progress, the recovery organization may be augmented or reduced as needed to maintain effectiveness and meet ongoing operational needs.

In general, Dominion would not expect a recovery organization to be necessary following declaration and termination of a Notification of Unusual Event or Alert.

3. Changes in Organizational Structure

The recovery process is implemented when the facility's emergency response organization managers, with concurrence of Commonwealth of Virginia and Federal agencies, have determined the station to be in a stable and controlled condition. Upon the determination, Dominion notifies the NRC Operations Center, the Virginia EOC, and the risk jurisdiction EOCs that the emergency has been terminated and any required recovery has commenced.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

4. Updating Total Population Exposure During Recovery Operations

Total population doses are periodically estimated in the affected sectors and zones utilizing population distribution data from within the affected areas. Health Physics personnel initially determine Total Effective Dose Equivalent (TEDE) due to external exposure from airborne material, external exposure from ground deposition, and internal exposure due to inhalation. Initial calculations also are performed for determination of Thyroid Committed Dose Equivalent (CDE) resulting from inhalation of radioiodines. The methodology used is consistent with that presented in EPA-400-R-92-001. Determination of total population doses includes assessments of exposure received from (but not necessarily limited to) immersion, inhalation, ground shine, and ingestion of radioactive materials.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

N. Exercises and Drills

Dominion implements a program of periodic drills and exercises to evaluate major portions of emergency response capabilities and to develop and maintain key emergency response skills. Identified deficiencies are corrected.

1. Exercises

a. Exercise Scope

Dominion conducts emergency exercises in accordance with NRC and FEMA rules (e.g., 10 CFR 50.47(b)(14) and 44 CFR 350.9) and policy. These exercises are developed and implemented to periodically test and evaluate major portions of the affected emergency plans, procedures, and organizations.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Exercise Scenarios and Participation

Dominion conducts exercises on a periodic basis. These exercises allow demonstration of the key skills specific to emergency response duties in the control room, TSC, OSC, EOF, and joint information center in order to implement the principal functional areas of emergency response. The exercises:

- Test the adequacy of timing and content of implementing procedures and methods
- Test emergency equipment and communications networks
- Test the public notification system
- Test the familiarity of emergency organization personnel with their duties

Scenarios are varied so major elements of the plans and preparedness organizations are tested, including, at least once during the eight-year exercise cycle, the following:

- Hostile action directed at the plant site
- No radiological release or an unplanned minimal radiological release that does not require public protective actions
- An initial classification of or rapid escalation to a Site Area Emergency or General Emergency
- Implementation of strategies, procedures, and guidance developed under §50.54(hh)(2)
- Integration of offsite resources with onsite response.

Dominion will conduct a full participation exercise (which tests as much of the licensee, Commonwealth of Virginia and risk jurisdiction emergency plans as is reasonably achievable without mandatory public participation) within two years before initiation of scheduled initial fuel loading. This exercise will include (consistent with existing FEMA rules and policy) participation by the Commonwealth of Virginia, State of Maryland and affected local governments within the plume exposure pathway EPZ and the ingestion exposure pathway EPZ. The eight-year exercise for Unit 3 starts in the year the first hostile action exercise is conducted for Units 1 & 2.

If the full participation exercise is conducted more than one year before the scheduled date for initial fuel loading, Dominion will conduct an exercise that tests the onsite emergency plans within one year before the scheduled date for initial fuel loading. This exercise may, but need not, have participation by the Commonwealth of Virginia and risk jurisdictions.

Dominion conducts an exercise of its onsite emergency plan every two years. The exercise may be included in the biennial full participation exercise discussed below. Scenarios for these exercises are submitted to NRC at least 60 days before their scheduled use.

Dominion conducts exercises involving full participation by offsite authorities having a role under the plan at least biennially. If any offsite authority has a role under a radiological response plan for more than one site, Dominion offers that authority an opportunity to participate in one exercise every two years.

Dominion offers the Commonwealth of Virginia and State of Maryland, an opportunity to participate in the ingestion pathway portion of exercises, regardless of the state's participation in other licensed facility's emergency exercises.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

c. Off-hours Drills and Exercises

At least once every eight-year exercise cycle, provisions will be made to start a drill or exercise between 6:00 pm and 4:00 am on a weekday or during a weekend. Dominion conducts unannounced exercises on a periodic basis, to the extent such exercises can be supported by affected internal and external organizations.

2. Drills

Dominion maintains adequate emergency response capabilities between biennial exercises by conducting drills, including at least one drill involving a combination of some of the principal functional areas of onsite emergency response capabilities. The principal functional areas of emergency response include activities such as:

- Management and coordination of emergency response
- Accident assessment
- Event classification

- Notification of offsite authorities
- Assessment of the onsite and offsite impact of radiological releases
- Protective action recommendation development
- Protective action decision making
- Plant system repair and mitigative action implementation

Upon request, Dominion allows affected Commonwealth of Virginia and risk jurisdiction governments located within the plume exposure pathway EPZ to participate in the drills.

During these drills, activation of all of the ERFs may not be necessary. Dominion may use the drills to consider accident management strategies, provide supervised instruction, allow the operating staff to resolve problems and focus on internal training objectives. Dominion may include one or more drills as portions of an exercise. Prior to initial operation and at least once each subsequent eight-year exercise cycle, a drill or exercise will be conducted that demonstrates the following EOF functions:

- Obtaining and displaying key plant data and radiological information for each unit the EOF serves.
- Analyzing plant technical information and providing technical briefings on event conditions and prognosis to licensee staff and offsite agency responders for each type of unit.

The activities undertaken in the event of an actual declared emergency may be used to satisfy emergency drill requirements, provided that these activities demonstrate adequate execution of the specified activities.

The drill program includes the following:

a. Communications Drills

Dominion conducts monthly tests of communications with Commonwealth of Virginia and risk jurisdiction governments within the plume exposure pathway EPZ, as identified in Section II.A.

Dominion conducts quarterly tests of communications with Federal emergency response organizations, as identified in Section II.A.

Dominion conducts annual tests of communications between the facility, Virginia and risk jurisdiction EOCs, and field assessment teams.

Communications drills evaluate both the operability of the communications system(s) and the ability to understand message content.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

b. Fire Drills

Dominion conducts fire drills as required by Section 9.5.1 of the FSAR.

c. Medical Emergency Drills

Dominion conducts medical emergency drills that include a simulated contaminated injured individual and participation by the local support services agencies (i.e., medical transportation and offsite medical treatment facility) on a yearly basis.

Appendix 8 provides a cross-reference to the related provisions in risk jurisdiction RERPs.

d. Radiological Monitoring Drills

Dominion conducts radiological monitoring drills, involving both onsite and offsite radiological monitoring activities on a yearly basis. Radiological monitoring drills include collection and analysis of the sample media for which the facility is responsible, communications with monitoring teams, and recordkeeping activities. Dominion may coordinate radiological monitoring drills with those drills conducted by Commonwealth of Virginia and risk jurisdiction government entities or may conduct these drills independently.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

e. Health Physics Drills

Dominion conducts on-site Health Physics drills on a semi-annual basis. Health Physics drills include:

- Response to and analysis of simulated elevated airborne and liquid samples and direct radiation measurements in the environment
- Analysis of in-plant liquid samples with simulated or actual elevated radiation levels

Appendix 8 provides a cross-reference to the related provisions in the COVRERP.

3. Conduct of Drills and Exercises

Dominion develops drill and exercise scenarios and related materials that clearly establish the following:

a. Basic objectives and evaluation criteria

b. Date, time period, location, and participating organizations

c. Simulated events

d. Time schedule of real and simulated initiating events

e. Narrative summary describing the conduct of the exercise or drill, including items such as simulated casualties, offsite response to the facility, personnel rescue, use of protective equipment, monitoring team deployment, and public information activities

f. Arrangements for official observers and the advance materials to be provided to them

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Exercise and Drill Evaluation

One or more qualified instructors/evaluators supervise and evaluate drills and exercises. A qualified instructor/evaluator is an individual whose knowledge, skills, and abilities have been evaluated by the Manager Emergency Preparedness or designee and determined to be sufficient for observing and evaluating the planned activities against the established criteria. For example, a qualified instructor/evaluator may be an individual who has been trained to fill the emergency response position to be observed or may be a supervisor or instructor for the position.

Exercises may be critiqued by Federal and Commonwealth of Virginia observers/evaluators.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Drill and Exercise Critiques

Dominion conducts a critique following conduct of the exercise. Participants may include selected Dominion, NRC, Commonwealth of Virginia, risk jurisdiction, and other participants and observers/evaluators. Input from the critique participants, is evaluated to determine the need for changes to the plan, procedures, equipment, facilities, and other components of the emergency preparedness and response program.

Dominion tracks identified corrective actions to completion using the facility's corrective action program.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

O. Radiological Emergency Response Training

1. General

Dominion implements a training program that provides for initial training and retraining for individuals who have been assigned emergency response duties, including both onsite staff and offsite individuals who may be called on to provide assistance in the event of an emergency.

The description of the emergency preparedness training program in SSAR Section 13.3.2.2.2.o is incorporated by reference.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

a. Offsite Emergency Response Training

Dominion provides for the conduct of site-specific training for offsite personnel who may be called upon to provide assistance in the event of an emergency. This includes emergency responders employed by agencies identified in Section II.A.

Dominion offers training for affected hospital, ambulance/rescue, police, and firefighting personnel that includes their expected emergency response roles, notification procedures, and radiation protection precautions. For these and any other offsite emergency responders who may be required to enter the site under emergency conditions, Dominion offers training that addresses site access procedures and identifies (by position) the individual who will control their activities on site.

Training for offsite support personnel includes the following, to the extent appropriate to the assigned duties and responsibilities:

- The basic scope of the emergency plan
- Emergency classifications
- Notification methods
- Basic radiation protection
- Station access procedures
- The individual, by title, in the station emergency response organization who will direct their activities onsite
- Definition of support roles

Appendix 8 provides a cross-reference to these provisions in State and Local Plans, as applicable.

b. Mutual Aid Agreements

This NUREG-0654 criterion does not apply to the licensee, but to State and local plans. Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Onsite Emergency Response Training

The emergency response training program includes on-site Dominion personnel who may be called upon to respond to an emergency. The training program includes, to the extent appropriate, practical drills consistent with Section II.N, during which individuals demonstrate the ability to discharge the assigned emergency response function. The instructor/evaluator corrects any erroneous performance noted during these practical drills and, as appropriate, demonstrates proper performance consistent with approved procedures and accepted standards.

3. First Aid Team Training

Dominion provides first aid training equivalent to Red Cross Multi-Media Training (e.g., Red Cross First Aid/Cardiopulmonary Resuscitation (CPR), Automated External Defibrillation (AED) for the Workplace), consistent with the projected hazards and events, for those individuals assigned to render treatment during a medical emergency.

4. Emergency Response Training and Qualification

Dominion conducts a program for instructing and qualifying personnel who implement this plan. Individuals complete the required training prior to assignment to a position in the emergency response organization. The training program establishes the scope, nature, and frequency of the required training and qualification measures.

Emergency response personnel are trained in the following subjects, to the extent appropriate to their duties and responsibilities: emergency response organization; emergency classification system; personnel accountability; emergency exposure limits; ERFs; security access control and site evacuation process; and exposure control techniques.

Dominion implements a program to provide position-specific emergency response training for designated members of the emergency response organization. The content of the training program is appropriate for the duties and responsibilities of the assigned position. The affected positions, and the scope of the associated training programs, include:

a. Emergency response directors and coordinators – Emergency condition assessment and classification, notification systems and procedures, organizational interfaces, site evacuation, radiation exposure controls, offsite support, and recovery.

b. Accident assessment personnel - Emergency condition assessment and classification, notification systems and procedures, organizational interfaces.

c. Radiological monitoring and analysis personnel – Dose assessment, emergency exposure evaluation, protective measures, protective actions, contamination control and decontamination, monitoring systems and procedures.

d. Police, Security and firefighting personnel - Notification of station personnel, facility activation, personnel accountability and evacuation, and access control. (Note: Offsite police and firefighting personnel will receive training consistent with Section II.O.1.a.)

e. Damage control/repair/corrective action teams - Damage control organization, communication systems, and planning and coordination of damage control tasks.

f. First aid/rescue personnel - Emergency organizational interfaces, firefighting, search and rescue procedures, and communications systems.

g. Local support services/emergency service personnel – Training consistent with Section II.O.1.a.

h. Medical support personnel - Training consistent with Section II.O.1.a.

i. Corporate office support personnel - Applicable procedures and organizational interfaces.

j. Emergency communicators - Notifications and reports to offsite authorities and communication systems as appropriate for individual position assignments.

Dominion offers to provide training for local support services personnel, including emergency service, police, and firefighting personnel, consistent with Section II.O.1.a.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Retraining

Dominion conducts, or supports the conduct of, annual retraining for those categories of emergency response personnel listed in Section II.O. Failure of Dominion ERO members to successfully complete this training in a timely manner as specified in plant training program requirements results in the individual's removal from the ERO pending completion of the required training.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

P. Responsibility for the Planning Effort

Dominion implements an organizational structure and processes to periodically review, update, distribute, and control this plan consistent with facility quality assurance and document control requirements. Dominion also implements a program to provide training to personnel responsible for the emergency planning effort appropriate to their duties and responsibilities.

The descriptions of plans for maintaining emergency preparedness in SSAR Section 13.3.2.2.2.p are incorporated by reference.

1. Training

Dominion develops and implements a process to provide training to the Manager Emergency Preparedness and support staff. Training may include formal education, professional seminars, plant-specific training, industry meetings, and other activities and forums that provide for an exchange of pertinent information.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

2. Responsibility for Radiological Emergency Response Planning

The *Site Vice President* holds the overall authority and responsibility for ensuring that an adequate level of emergency preparedness is maintained.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

3. Manager Emergency Preparedness

Dominion establishes a Manager Emergency Preparedness position. The incumbent is responsible for developing and updating site emergency plans and coordination of these plans with other response organizations.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

4. Plan Reviews and Updates

The Manager Emergency Preparedness is responsible for conducting or coordinating an annual review of this plan to verify the plan and its supporting agreements are current. This review includes consideration of any changes that may be necessary to address issues identified during the course of drills, exercises, and actual emergency events. The Manager Emergency Preparedness also reviews and updates the plan and agreements as needed (e.g., following changes to Commonwealth of Virginia and risk jurisdiction plans that may affect the content of the facility's plan) to verify they remain current.

Evacuation Time Estimates (ETEs) are reviewed against estimated EPZ permanent resident population changes at least once a year and within 365 days of the date of the previous ETE or its most recent review. Increases of ETEs greater than the limits detailed in 10 CFR 50 Appendix E require the ETE analysis be updated. The decennial ETE and its updates are submitted to NRC as required by 10 CFR 50 Appendix E.

Upon completion of the annual review, the Manager Emergency Preparedness (or designee) incorporates any necessary changes. Changed pages are marked and dated to highlight the changes. The Manager Emergency Preparedness forwards the updated plan to the Facility Safety Review Committee (FSRC) for review and approval. If a proposed revision is judged to decrease the effectiveness of these documents with respect to the requirements of 10 CFR 50.47(b) or 10 CFR Part 50, Appendix E, the proposed changes are submitted to the NRC for approval in accordance with the requirements of 10 CFR 50.54(q) prior to implementation.

Following completion of the annual review and any required updates, the Manager Emergency Preparedness certifies the plan to be current.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

5. Distribution of Revised Plans

The facility’s document control organization distributes the updated plan to organizations/individuals with responsibility for implementing the plans.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

6. Supporting Plans

The following list identifies supporting plans and their sources.

- Commonwealth of Virginia Plan (Virginia Emergency Operations Plan, Radiological Emergency Response Basic Plan)
- Louisa County Radiological Emergency Response Plan
- Spotsylvania County Radiological Emergency Response Plan
- Orange County Radiological Emergency Response Plan
- Caroline County Radiological Emergency Response Plan
- Hanover County Radiological Emergency Response Plan
- Virginia Commonwealth University Medical Center Radiation Emergency Plan
- Department of Energy – Federal Radiological Monitoring and Assessment Center Operations Plan

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

7. Implementing Procedures

Appendix 5 provides a topical listing of EPIPs that support this plan.

Certain emergency plan features recommended by NUREG-0654 (e.g., Evaluation Criterion D.1, which addresses identification of parameter values and status for each emergency class, and Evaluation Criterion I.3, which addresses methods and techniques for determining source terms and the magnitude of releases) are procedural in nature and have been more appropriately placed in plant procedures, including EPIPs. Changes to the affected portions of these procedures are developed and approved consistent with the requirements of 10 CFR 50.54(q).

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

8. Table of Contents

The format for this Emergency Plan directly follows the format of NUREG-0654, Rev. 1 as outlined in the Table of Contents.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

9. Emergency Plan Reviews

Dominion's independent assessment organization performs, or oversees the performance of, periodic independent reviews of the emergency preparedness program consistent with the requirements of 10 CFR 50.54(t). The reviews include, at a minimum, the following:

- The Emergency Plan
- Emergency plan implementing procedures and practices
- The emergency preparedness training program
- Readiness testing (e.g., drills and exercises)
- ERFs, equipment, and supplies
- Interfaces with Commonwealth of Virginia and risk jurisdiction government agencies

Dominion's independent assessment organization subjects review findings to management controls consistent with the facility's corrective action program.

Dominion's independent assessment organization documents review results and improvement recommendations and reports these results to Dominion management. Dominion makes those portions of the reviews that address the adequacy of interfaces with Commonwealth of Virginia and risk jurisdiction governments available to the affected governments.

Dominion retains review records for a period of at least five years in accordance with facility document control requirements.

10. Emergency Telephone Numbers

The Manager Emergency Preparedness is responsible for ensuring a review of the emergency personnel notification list is performed on a quarterly basis and for ensuring required revisions are incorporated. Documentation of this review shall be filed by the facility's records management organization.

Appendix 8 provides a cross-reference to the related provisions in the COVRERP and risk jurisdiction RERPs.

III. References and Appendices

A. Cited References

1. U.S. Nuclear Regulatory Commission, “Early Site Permits; Standard Design Certifications; And Combined Licenses For Nuclear Power Plants,” 10 CFR Part 52, as amended.

2. U.S. Nuclear Regulatory Commission, “Domestic Licensing Of Production And Utilization Facilities,” 10 CFR Part 50, as amended.

3. U.S. Nuclear Regulatory Commission, “Emergency Plans,” 10 CFR 50.47, as amended.

4. U.S. Nuclear Regulatory Commission, “Emergency Planning and Preparedness for Production and Utilization Facilities,” 10 CFR Part 50, Appendix E, as amended.

5. U.S. Nuclear Regulatory Commission, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants” NUREG-0654/FEMA-REP-1, Revision 1, October 1980.

6. U.S. Nuclear Regulatory Commission, “Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants,” NUREG 75/014 (WASH-1400), October 1975.

7. U.S. Nuclear Regulatory Commission, “Planning Basis for the Development of State and Local Government Radiological Emergency Response Plans in Support of Light Water Nuclear Power Plants,” NUREG-0396; EPA 520/1-78-016, December 1978.

8. U.S. Nuclear Regulatory Commission, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” Regulatory Guide 1.183, July 2000.

9. GE Nuclear Energy, “ESBWR Design Control Document,” Revision 5, May 2008.

10. North Anna Power Station Unit 3 Final Safety Analysis Report, Revision 1, November 2008.

11. U.S. Department of Energy, “Federal Radiological Monitoring and Assessment Center Operations Plan,” DOE/NV 11718-080, December 2005.

12. U.S. Department of Homeland Security, “National Response Framework,” January 2008.

13. [Deleted]

14. U.S. Nuclear Regulatory Commission, "Emergency Planning and Preparedness for Nuclear Power Reactors," Regulatory Guide 1.101, Revision 3, August 1992.

15. U.S. Environmental Protection Agency, "Manual of Protective Action Guides for Nuclear Incidents," EPA-400-R-92-001, 1991.

16. KLD Associates, Inc., "Development of Evacuation Time Estimates for North Anna Power Station," Revision 1, September 2008.

17. U.S Nuclear Regulatory Commission, "Development of Evacuation Time Estimate Studies for Nuclear Power Plants," NUREG/CR-6863, January 2005.

18. U.S. Nuclear Regulatory Commission, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants - Guidance for Protective Action Strategies," NUREG-0654/FEMA-REP-1, Supplement 3, November 2011.

19. North Anna Early Site Permit Application, Revision 9, September 2006.

20. KLD Associates, Inc., "North Anna Power Station - Development of Evacuation Time Estimates," Revision 1, November 2012.

21. U.S. Nuclear Regulatory Commission, "Criteria for Development of Evacuation Time Estimate Studies," NUREG/CR-7002, September 2011.

B. Supplemental References

1. USNRC IN 91-77- Shift Staffing at Nuclear Power Plants

2. USNRC IN 93-81 – Implementation of Engineering Expertise On Shift

3. USNRC IN 95-48 – Results of Shift Staffing Study

4. USNRC IN 86-16 – NRC On-Scene Response During a Major Emergency

5. USNRC RIS 2002-21 – National Guard and Other Emergency Responders Located in the Licensee's Controlled Area

6. NEI 99-01 – Methodology for Development of Emergency Action Levels

7. USNRC RIS 2003-18 - Use of NEI 99-01, Methodology for Development of Emergency Action Levels (including Supplements 1 and 2)

8. USNRC IN 97-05 – Offsite Notification Capabilities

9. USNRC RIS 00-011 – NRC Emergency Telecommunications System, including Supplement 1

10. USNRC IN 87-58 – Continuous Communications Following Emergency Notifications

11. USNRC IN 93-53 – Effect of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned

12. USNRC IN 97-05 – Offsite Notification Capabilities

13. USNRC IEB 79-18 – Audibility Problems Encountered on Evacuation of Personnel from High-Noise Areas

14. USNRC RIS 2002-16 – Current Incident Response Issues

15. FEMA-REP-11 – Guide to Preparing Emergency Public Information Materials

16. USNRC IEC 80-09 – Problems with Plant Internal Communications Systems

17. USNRC IN 85-44 – Emergency Communications System Monthly Test

18. USNRC IN 86-16 – NRC On-Scene Response During a Major Emergency

19. USNRC IN 93-53 – Effect of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned

20. USNRC IN 2004-19 – Problems Associated with Back-Up Power Supplies to Emergency Response Facilities and Equipment

21. USNRC IN 2002-14 – Ensuring a Capability to Evacuate Individuals, Including Members of the Public, from the Owner-Controlled Area

22. USNRC IN 88-15 – Availability of USFDA-Approved Potassium Iodide for Use in Emergencies Involving Radioactive Iodine

23. USNRC IN 96-19 – Failure of Tone alert Radios to Activate When Receiving a Shortened Activation Signal

24. USNRC IN 2002-25 – Challenges to Licensees' Ability to Provide Prompt Public Notification and Information During an Emergency Preparedness Event

25. USNRC IN 2005-06 – Failure to Maintain Alert and Notification System Tone Alert Radio Capability

26. USNRC RIS 01-016 – Update of Evacuation Time Estimates

27. USNRC RIS 2003-12 – Clarification of NRC Guidance for Modifying Protective Actions
28. USNRC RIS 2004-13 - Consideration of Sheltering in Licensee's Range of Protective Action Recommendations, including Supplement 1
29. USNRC RIS 2005-08 – Endorsement of NEI Guidance “Range of Protective Actions for Nuclear Power Plant Incidents”
30. FEMA-REP-10 – Guide for the Evaluation of Alert and Notification systems for Nuclear Power Plants
31. USNRC IN 98-020 – Problems with Emergency Preparedness Respiratory Protection Programs
32. USNRC IN 86-98 – Offsite Medical Services
33. 44 CFR 350, Review And Approval of State and Local Radiological Emergency Plans and Preparedness
34. USNRC IN 85-41 – Scheduling of Pre-Licensing Emergency Preparedness Exercises
35. USNRC IN 87-54 – Emergency Response Exercises
36. USNRC Bulletin 2005-02 – Emergency Preparedness and Response Actions for Security-Based Events
37. USNRC RIS 2005-02 – Clarifying the Process for Making Emergency Plan Changes, February 2005
38. USNRC RIS 2006-02 – Good Practices for Licensee Performance During the Emergency Preparedness Component of Force-on-force Exercises
39. USNRC RIS 2006-03 – Guidance on Requesting an Exemption from Biennial Emergency Preparedness Exercise Requirements
40. USNRC Generic Letter 80-34 – Clarification of NRC Requirements for Emergency Response Facilities at Each Site
41. USNRC Generic Letter 80-93 – Emergency Preparedness
42. USNRC Generic Letter 81-10 – Post-TMI Requirements for the Emergency Operations Facility
43. USNRC Generic Letter 89-15 – Emergency Response Data System

44. USNRC Generic Letter 91-14 – Emergency Telecommunications

45. USNRC IE Bulletin 80-15 – Possible Loss of Emergency Notification System (ENS) With Loss of Offsite Power

46. NSIR/DPR-ISG-01, “Emergency Planning for Nuclear Power Plants,” Revision 0 (November 2011)

C. Appendices

Appendix 1 - [reserved]

Appendix 2 - Assessment and Monitoring for Actual or Potential Offsite Consequences of a Radiological Emergency

Appendix 3 - Public Alert and Notification System

Appendix 4 - Evacuation Time Estimates (summary)

Appendix 5 - Emergency Plan Implementing Procedures – Topical List

Appendix 6 - Emergency Equipment and Supplies

Appendix 7 - Certification Letter

Appendix 8 - Cross-Reference to Regulations, Guidance, and State and Local Plans

Appendix 1–Reserved

Appendix 2–Assessment and Monitoring for Actual or Potential Offsite Consequences of a Radiological Emergency

1.0 Introduction

This appendix provides information regarding atmospheric transport and diffusion assessment discussed in Appendix 2 to NUREG-0654, Rev. 1, "Meteorological Criteria for Emergency Preparedness at Operating Nuclear Power Plants."[1] Three topics are identified in Appendix 2 to NUREG-0654:

- Meteorological measurements
- Atmospheric transport and diffusion assessment
- Remote interrogation

Since they are discussed in FSAR Section 2.3, only a brief discussion of meteorological measurements is provided in this Appendix. Similarly, information regarding remote interrogation is included in SSAR Section 2.3 and is only briefly discussed below. This Appendix describes the conceptual design of the software used for the atmospheric transport and diffusion assessment models used by Dominion for its nuclear power plants, including Unit 3.

2.0 Discussion

10 CFR 50.47 requires that the emergency plan provide "adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use."[2] 10 CFR 50, Appendix E, requires emergency facilities and equipment shall include "equipment for determining the magnitude of and for continuously assessing the impact of the release of radioactive materials to the environment."[3]

2.1 Meteorological Measurements

Appendix 2 to NUREG-0654, Rev. 1 clarifies that in order to address the requirement in Appendix E, "the nuclear power plant operator shall have meteorological measurements from primary and backup systems."[4] The design of the system for meteorological measurement system is discussed in FSAR Section 2.3. This design addresses the guidance provided in Supplement 1 to NUREG-0737.[5]

1. U.S. Nuclear Regulatory Commission, NUREG-0654/FEMA REP-1, Rev. 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Washington, DC, November 1980.
2. 10 CFR 50.47(b)(9)
3. 10 CFR 50, Appendix E, IV.E.2
4. NUREG-0654, Rev. 1, Appendix 2, "Meteorological Criteria for Emergency Preparedness at Operating Nuclear Power Plants," Washington, DC, November 1980.
5. U.S. Nuclear Regulatory Commission, NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements," Washington, DC, January 1983

2.2 Atmospheric Transport and Diffusion Assessment

Atmospheric transport and diffusion assessment requirements are discussed in Appendix E to 10 CFR 50 which states, “the means to be used for determining the magnitude of and for continually assessing the impact of the release of radioactive material shall be described.”[1] Two classes of atmospheric transport and diffusion models are discussed in NUREG-0654. This Appendix discusses the software used for Unit 3, which addresses guidance associated with the “Class B” model described in Appendix 2 of NUREG-0654, Rev. 1: “a numerical model which predicts the spatial and temporal variations of plume distribution and provides estimates of deposition and relative concentration of radioactivity within the plume exposure and ingestion pathway emergency planning zones for the duration of any radioactive materials releases during a declared emergency.”[2]

2.3 Remote Interrogation

Guidance concerning remote interrogation is also discussed in Appendix 2 of NUREG-0654, Rev. 1. The guidance supports the requirement in 10 CFR 50, Appendix E for “provisions for communications among the nuclear power reactor control room, the onsite technical support center and the near-site emergency operations facility; and among the nuclear facility, the principal State and local emergency operations centers, and field assessment teams.”[3] Provisions related to remote interrogation and communications are discussed in SSAR Section 2.3.

3.0 Conceptual Design: Atmospheric Transport and Diffusion Assessment

The remainder of this Appendix focuses on the conceptual design for the atmospheric transport and diffusion assessment models used by Dominion. Inspections, tests, analyses, and acceptance criteria (ITAAC) address requirements in 10 CFR 50.47(b)(9), discussed previously in this Appendix, and address evaluation criteria from NUREG-0654, Rev. 1 that are discussed in Section II.I of this plan. The conceptual design addresses the following program elements for accident assessment:

- The means exist to provide initial and continuing radiological assessment throughout the course of an accident. This addresses both Generic ITAAC Element 6.1 and the requirements of SSAR Section 13.3.2.2.2.i.
- The means exist to determine the source term of releases of radioactive material within plant systems, and the magnitude of the release of radioactive materials based on plant system parameters and effluent monitors. This addresses both Generic ITAAC Element 6.2 and the requirements of SSAR Section 13.3.2.2.2.h.3.

1. 10 CFR 50, Appendix E, IV.B
2. NUREG-0654, Rev. 1, Appendix 2, “Meteorological Criteria for Emergency Preparedness at Operating Nuclear Power Plants,” Washington, DC, November 1980.
3. 10 CFR 50, Appendix E, IV.E.9.c

- The means exist to continuously assess the impact of the release of radioactive materials to the environment, accounting for the relationship between effluent monitor readings, and onsite and offsite exposures and contamination for various meteorological conditions. This addresses both ITAAC 6.1 (COLA Part 10, Table 2.3-1) and the requirements of SSAR Section 2.3.3.1.1.
- The means exist to make rapid assessment of potential magnitude and locations of any radiological hazards through gaseous release pathways. This addresses both ITAAC 6.5 (COLA Part 10, Table 2.3-1) and the requirements of SSAR Section 13.3.2.2.2.i.1.
- The means exist to estimate integrated dose from the projected and actual dose rates, and for comparing these estimates with the EPA protective action guides (PAGs). This addresses both ITAAC 6.7 (COLA Part 10, Table 2.3-1) and the requirements of SSAR Section 13.3.2.2.2.k.3.

3.1 Overview, Introduction, and Functions

The software system is designed for use by Dominion's nuclear power plant units to address their emergency preparedness and accident analyses needs. This software is referred to as MIDAS (Meteorological Information and Dose Assessment System) or MIDAS-NU (MIDAS-Nuclear). Section 3.2 discusses the accident and routine release calculations. Section 3.3 is divided into general categories such as “data acquisition,” “data summary display,” and “utilities.”

3.1.1 Summary and Purpose

The MIDAS system is comprised of a series of software components that function in a multi-tasked Microsoft Windows™ environment. The computer receives data from external devices including meteorological and plant effluent monitors. Data can be received via serial port devices or over a local area network (LAN)/wide area network (WAN) connection. Reports are displayed on the screen and printed out. Also, reports can be sent via LAN/WAN connection to central control units.

Input data are available periodically from measuring devices on a meteorological tower and from effluent monitors that measure concentrations or dose. Calculations are made in the computer that can be used to determine the health impact of the release. The user schedules runs from a Graphic User Interface (GUI).

The released material is tracked in the environment as it is carried by the wind and dispersed. The three most important parameters are wind speed, wind direction, and atmospheric turbulence. The wind speed determines the initial dilution and plume travel speed. The wind direction determines the effluent plume trajectory. The turbulence determines the rate of spread or growth of the plume. These factors, along with assumptions related to the rate of deposit of particulate matter, are used to determine plume concentration and deposition as a function of location and time.

The accumulated doses to a stationary person are computed based on the estimated variation of the effluent concentration and deposition. The plume tracks are plotted on site maps.

The time-integrated doses resulting from a longer exposure or release can be calculated and results plotted or printed in tabular form. For proper display of time-integrated long-term releases, doses from each release are added on the grid and an isopleth (filled contour showing potentially dangerous areas) is plotted.

3.1.2 General Software Specifications

Software is written in ANSI 1977 compatible FORTRAN, Visual Basic 5 (compiled), or C. The modular nature of the software facilitates modifications. Software modifications follow established quality assurance procedures. Each computer is run under the Microsoft Windows™ operating system as a stand-alone unit. Separate files are available for receipt of meteorological and effluent monitor data. Running of the plume model calculations does not interfere with ongoing, real-time data acquisition and storage.

3.1.3 User Interface

The software is written to interact with the user from the GUI. The user is prompted for information needed from a series of input screens. The software checks for invalid entries insofar as practicable. The user is not allowed to confirm an input screen until requirements for input from that screen are satisfied. Entries are made with the mouse including those on the keypad pop-up menu.

3.2 Accident Calculations

The primary functions of the MIDAS system are to collect and process data, perform atmospheric dispersion calculations, prompt the user for minimum input, estimate dose due to radiological exposure, and display results in a color graphics format. MIDAS-NU incorporates a fast-running, time-dependent, variable trajectory, Gaussian plume segment atmospheric dispersion model. The transport portion of model enables the plume direction and location to vary every 15 minutes as the wind speed, direction, and other weather conditions change. Radiation doses/exposures are accumulated in a polar grid, enabling plume direction changes when the meteorological conditions vary. Results are contoured and displayed on a map. Wind fields are computed from onsite meteorological data input to the system.

MIDAS-NU also has a simple model that estimates transport and dispersion of releases in a uniform wind field, with no changes in the meteorological or release parameters. This is used only in the back calculation module.

It is important to note that the models used in MIDAS-NU are estimating tools. MIDAS-NU results are highly dependent on the accuracy of the current local weather conditions and other input data (e.g., terrain, building characteristics, and amount of material released) that are processed within MIDAS-NU. The more accurate the data that is supplied to MIDAS-NU, the more accurate its predictive estimates will be. Due to uncertainties associated with input information and inherent in dispersion models in general, MIDAS-NU predictions should not necessarily be regarded as fact.

3.3 Data Acquisition

Meteorological and field sensor data is collected and its quality checked to assure that an adequate database is available for dispersion calculations and support of emergency operations. Hardware and software specific to the data being collected may be needed in order to collect the data and transmit it to the MIDAS system. The collected data are stored within the overall MIDAS system and therefore available for calculations in the future. Fifteen-minute averages of meteorological data are computed from the data collected and written into the appropriate files. Bad or missing data will be flagged by the data codes for each record. There are a number of tasks in MIDAS that can be used to display or edit the data. A task is a discrete processing action within the software that performs an important function. For each function selected a different task list will be shown. The tasks are selected by clicking on the task text and then “Run Task” to execute. These tasks are accessed using the MDVDCOLL icon. When selected the user will be presented with the menu shown below. Every task may not be available on every system.

Calculations assume that the hourly average is representative of the 15 minute period centered on each 15 minute period (00, 15, 30, 45) (e.g., the time on the hour is from 7.5 minutes before the hour to 7.5 minutes after the hour.).

For the hourly averaging, the following technique is used:

- Speeds, delta temperatures, temperatures, and miscellaneous sensors are averaged. Directions are vector averaged.
- Rain is accumulated.
- Field radiation monitor data are reported as rad/hr.
- Cloud cover is in percent.
- Effluent monitor data are averaged.

3.4 Data Summary Displays

After the databases have been conditioned, the file contents can be inspected using a series of data summary displays described in the following sections. The resulting function/task menu is displayed.

When the Average display tasks are selected the user will enter parameters to describe the data to be displayed. These parameters will include the amount of data displayed for each parameter (time groups), the sensors to be displayed, the date range (start date and end date), averaging time for the data (data frequency) and the type of data (raw or workspace). Similar data are required for Data Quality.

3.4.1 Meteorological Displays

A task is provided to print the hour or 15 minute meteorological parameter averages received over any specified time period (within the bounds of the file). The “trend plot” tasks can be used to plot meteorological data making it easy to spot problem areas in the data. The data summary routines can be used in conjunction with edits to inspect and correct data. The summaries may show, for example, that a particular edit was not successful or resulted in data that was suspect. Further edits of data would then be in order.

3.4.2 Radiological Displays

Radiation monitors typically send gamma dose rate measurements (in R/hr). Averages would be updated every 15 minutes.

3.5 Utilities

The system incorporates a series of utilities that are separate from standard Microsoft WINDOWS™ utilities. These include the ability to initialize raw data and other types of files as appropriate. They also include capability to save (archive) from or restore to workspace or raw data files. Other utilities necessary for system startup will be provided along with any data that must be loaded.

Appendix 3–Public Alert and Notification System

The Public Alert and Notification System is the same as that used for NAPS Units 1 and 2. COVRERP Appendix 3 provides a description of the Public Alert and Notification System.

Appendix 4–Evacuation Time Estimates (summary)*

*Note: Attachment 4 is the executive summary from the full report.

EXECUTIVE SUMMARY

This report describes the analyses undertaken and the results obtained by a study to develop Evacuation Time Estimates (ETE) for the North Anna Power Station (NAPS) located in Louisa County, Virginia. ETE are part of the required planning basis and provide Dominion and State and local governments with site-specific information needed for Protective Action decision-making.

In the performance of this effort, guidance is provided by documents published by Federal Governmental agencies. Most important of these are:

- Criteria for Development of Evacuation Time Estimate Studies, NUREG/CR-7002, November 2011.
- Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, NUREG-0654/FEMA-REP-1, Rev. 1, November 1980.
- Development of Evacuation Time Estimates for Nuclear Power Plants, NUREG/CR-6863, January 2005.
- 10CFR50, Appendix E – "Emergency Planning and Preparedness for Production and Utilization Facilities"

Overview of Project Activities

This project began in February, 2012 and extended over a period of 9 months. The major activities performed are briefly described in chronological sequence:

- Attended "kick-off" meetings with Dominion personnel and emergency management personnel representing state and county governments.
- Accessed U.S. Census Bureau data files for the year 2010. Studied Geographical Information Systems (GIS) maps of the area in the vicinity of the NAPS, then conducted a detailed field survey of the highway network.
- Synthesized this information to create an analysis network representing the highway system topology and capacities within the Emergency Planning Zone (EPZ), plus a Shadow Region covering the region between the EPZ boundary and approximately 15 miles radially from the plant.
- Designed and sponsored a telephone survey of residents within the EPZ to gather focused data needed for this ETE study that were not contained within the census database. The survey instrument was reviewed and modified by the licensee and offsite response organization (ORO) personnel prior to the survey (survey from the 2007 COLA was used since EPZ demographics did not significantly change).
- Counties provided school and transportation resources data. Data for transient facilities

was collected through phone calls to specific facilities.

- The traffic demand and trip-generation rates of evacuating vehicles were estimated from the gathered data. The trip generation rates reflected the estimated mobilization time (i.e., the time required by evacuees to prepare for the evacuation trip) computed using the results of the telephone survey of EPZ residents.
- Following federal guidelines, the EPZ is subdivided into 25 Protective Action Zones (PAZ). These PAZ are then grouped within circular areas or "keyhole" configurations (circles plus radial sectors) that define a total of 41 Evacuation Regions.
- The time-varying external circumstances are represented as Evacuation Scenarios, each described in terms of the following factors: (1) Season (Summer, Winter); (2) Day of Week (Midweek, Weekend); (3) Time of Day (Midday, Evening); and (4) Weather (Good, Rain, Snow). One special event scenario involving the Kinetic Triathlon at Lake Anna State Park was considered. One roadway impact scenario was considered wherein a northbound segment of US-522 NB at CR-612 was closed for the duration of the evacuation.
- Staged evacuation was considered for those regions wherein the 2 mile radius and sectors downwind to 5 miles were evacuated.
- As per NUREG/CR-7002, the Planning Basis for the calculation of ETE is:
  - A rapidly escalating accident at the NAPS that quickly assumes the status of General Emergency such that the Advisory to Evacuate is virtually coincident with the siren alert, and no early protective actions have been implemented.
  - While an unlikely accident scenario, this planning basis will yield ETE, measured as the elapsed time from the Advisory to Evacuate until the stated percentage of the population exits the impacted Region, that represent "upper bound" estimates. This conservative Planning Basis is applicable for all initiating events.
- If the emergency occurs while schools are in session, the ETE study assumes that the children will be evacuated by bus directly to Evacuation Assembly Centers (EAC) located outside the EPZ. Parents, relatives, and neighbors are advised to not pick up their children at school prior to the arrival of the buses dispatched for that purpose. The ETE for schoolchildren are calculated separately.
- Evacuees who do not have access to a private vehicle will either ride-share with relatives, friends or neighbors, or be evacuated by buses provided as specified in each of the counties Radiological Emergency Response Plans (RERP). Those in special facilities will likewise be evacuated with public transit, as needed: bus, van, or ambulance, as required. Separate ETE are calculated for the transit-dependent evacuees, for homebound special needs population, and for those evacuated from special facilities.
- Attended final meeting with Dominion personnel and emergency management personnel representing state and county governments to review results and receive comments.

Computation of ETE

A total of 574 ETE were computed for the evacuation of the general public. Each ETE quantifies the aggregate evacuation time estimated for the population within one of the 41 Evacuation Regions to evacuate from that Region, under the circumstances defined for one of the 14 Evacuation Scenarios (41 x 14 = 574). Separate ETE are calculated for transit-dependent evacuees, including schoolchildren for applicable scenarios.

Except for Region R03, which is the evacuation of the entire EPZ, only a portion of the people within the EPZ would be advised to evacuate. That is, the Advisory to Evacuate applies only to those people occupying the specified impacted region. It is assumed that 100 percent of the people within the impacted region will evacuate in response to this Advisory. The people occupying the remainder of the EPZ outside the impacted region may be advised to take shelter.

The computation of ETE assumes that 20% of the population within the EPZ but outside the impacted region, will elect to "voluntarily" evacuate. In addition, 20% of the population in the Shadow Region will also elect to evacuate. These voluntary evacuees could impede those who are evacuating from within the impacted region. The impedance that could be caused by voluntary evacuees is considered in the computation of ETE for the impacted region.

Staged evacuation is considered wherein those people within the 2-mile region evacuate immediately, while those beyond 2 miles, but within the EPZ, shelter-in-place. Once 90% of the 2-mile region is evacuated, those people beyond 2 miles begin to evacuate. As per federal guidance, 20% of people beyond 2 miles will evacuate (non-compliance) even though they are advised to shelter-in-place.

The computational procedure is outlined as follows:

- A link-node representation of the highway network is coded. Each link represents a unidirectional length of highway; each node usually represents an intersection or merge point. The capacity of each link is estimated based on the field survey observations and on established traffic engineering procedures.
- The evacuation trips are generated at locations called "zonal centroids" located within the EPZ and Shadow Region. The trip generation rates vary over time reflecting the mobilization process, and from one location (centroid) to another depending on population density and on whether a centroid is within, or outside, the impacted area.
- The evacuation model computes the routing patterns for evacuating vehicles that are compliant with federal guidelines (outbound relative to the location of the plant), then simulate the traffic flow movements over space and time. This simulation process estimates the rate that traffic flow exits the impacted region.

The ETE statistics provide the elapsed times for 90 percent and 100 percent, respectively, of the population within the impacted region, to evacuate from within the impacted region. These statistics are presented in tabular and graphical formats. The 90th percentile ETE have been identified as the values that should be considered when making protective action decisions because the 100th percentile ETE are prolonged by those relatively few people who take longer to mobilize. This is referred to as the "evacuation tail" in Section 4.0 of NUREG/CR-7002.

The use of a public outreach (information) program to emphasize the need for evacuees to minimize the time needed to prepare to evacuate (secure the home, assemble needed clothes, medicines, etc.) should also be considered.

Traffic Management

This study references the comprehensive traffic management plans provided by Louisa, Spotsylvania, Orange, Caroline, and Hanover Counties, and identifies critical intersections.

Selected Results

A compilation of selected information is presented on the following pages in the form of Figures and Tables extracted from the body of the report; these are described below.

- Figure 6-1 displays a map of the NAPS EPZ showing the layout of the 25 PAZ that comprise, in aggregate, the EPZ.
- Table 3-1 presents the estimates of permanent resident population in each PAZ based on the 2010 Census data.
- Table 6-1 defines each of the 41 Evacuation Regions in terms of their respective groups of PAZ.
- Table 6-2 lists the Evacuation Scenarios.
- Tables 7-1 and 7-2 are compilations of ETE. These data are the times needed to clear the indicated regions of 90 and 100 percent of the population occupying these regions, respectively. These computed ETE include consideration of mobilization time and of estimated voluntary evacuations from other regions within the EPZ and from the Shadow Region.
- Tables 7-3 and 7-4 present ETE for the 2-mile region for un-staged and staged evacuations for the 90th and 100th percentiles, respectively.
- Table 8-7 presents ETE for the schoolchildren in good weather.
- Table 8-11 presents ETE for the transit-dependent population in good weather.
- Figure H-8 presents an example of an Evacuation Region (Region R08) to be evacuated under the circumstances defined in Table 6-1. Maps of all regions are provided in Appendix H.

Conclusions

- General population ETE were computed for 574 unique cases – a combination of 41 unique Evacuation Regions and 14 unique Evacuation Scenarios. Table 7-1 and Table 7-2 document these ETE for the 90th and 100th percentiles. These ETE range from 1:45 (hr:min) to 3:45 at the 90th percentile.
- Inspection of Table 7-1 and Table 7-2 indicates that the ETE for the 100th percentile are significantly longer than those for the 90th percentile. This is the result of the long trip generation "tail". As these stragglers mobilize, the aggregate rate of egress slows since many vehicles have already left the EPZ. Towards the end of the process, relatively few evacuation routes service the remaining demand. See Figures 7-7 through 7-20.

- Inspection of Table 7-3 and Table 7-4 indicates that a staged evacuation provides no benefits to evacuees from within the 2 mile region and unnecessarily delays the evacuation of those beyond 2 miles (compare Regions R02 and R04 through R15 with Regions R29 through R41, respectively, in Tables 7-1 and 7-2). See Section 7.6 for additional discussion.
- Comparison of Scenarios 9 (winter, weekend, midday) and 13 (winter, weekend, midday, special event) in Table 7-1 indicates that the special event does not materially affect the ETE. See Section 7.5 for additional discussion.
- Comparison of Scenarios 1 and 14 in Table 7-1 indicates that the roadway closure – a northbound section of US-522 NB at CR-612 – does not have a significant impact on the 90th or 100th percentile ETE. Sufficient reserve capacity exists on CR-612 to service the additional evacuating traffic demand. See Section 7.5 for additional discussion.
- There is minimal traffic congestion within the EPZ. All congestion within the EPZ clears by 2 hours and 10 minutes after the Advisory to Evacuate (earlier for winter cases). See Section 7.3 and Figures 7-3 through 7-6.
- Separate ETE were computed for schools, the one medical facility, transit-dependent persons and homebound special needs persons. The average single-wave ETE for these facilities are within a similar range as the general population ETE at the 90th percentile. See Section 8.
- Table 8-5 indicates that there are enough buses and wheelchair vans available to evacuate the entire transit-dependent population within the EPZ in a single wave, if transportation resources are shared by the counties. However, if for any reason transportation resources could not be shared, then Spotsylvania County would require a second wave for two of their schools in order to evacuate all schoolchildren. The second-wave ETE for schools do exceed the general population ETE at the 90th percentile. Mutual aid agreements with neighboring counties and assistance from the state could be used to address the shortfall in bus resources (See Section 8.4).
- The general population ETE at the 90th percentile is insensitive to reductions in the base trip generation time of 5½ hours. The general population ETE at the 100th percentile, however, closely mirrors trip generation time. See Table M-1.
- The general population ETE is insensitive to the voluntary evacuation of vehicles in the Shadow Region. Tripling the shadow evacuation percentage results in no change in the 90th percentile ETE. See Table M-2.
- An increase in permanent resident population of 150% or more, or a decrease in population of 85% or more results in ETE changes which meet the criteria for updating ETE between decennial Censuses. See Section M.3.
- The additional employees present during an outage concurrent with construction of the New Unit 3, does not affect the ETE, with the exception of the 90th percentile ETE for the 2-mile region, which decreased by 5 minutes. See Section M.4.

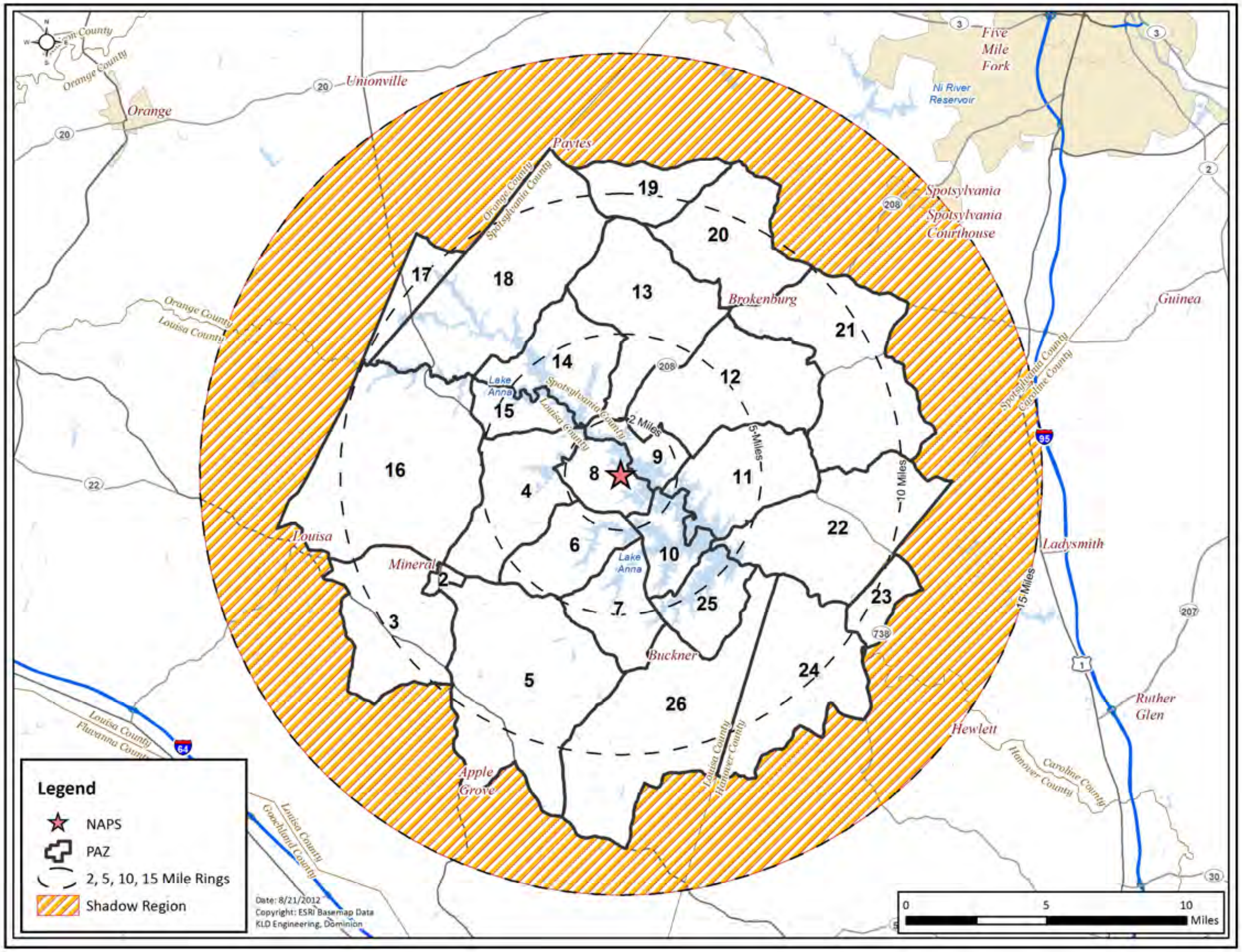


Figure 6-1. NAPS EPZ PAZ

Table 3-1. EPZ Permanent Resident Population

PAZ	2000 Population	2008 Population (Estimated)[1]	2010 Population
2	418	645	466
3	1,241	1,843	1,490
4	837	1,842	1,107
5	1,331	1,740	1,472
6	308	727	484
7	318	939	484
8	287	885	409
9	117	426	203
10	245	1,151	429
11	740	1,345	981
12	1,222	1,467	1,561
13	991	1,312	1,364
14	541	1,719	803
15	451	1,589	697
16	1,138	2,153	1,601
17	50	223	144
18	1,664	3,624	2,416
19	246	352	383
20	894	1,025	1,026
21	1,901	2,125	2,232
22	1,355	1,639	1,538
23	263	341	260
24	716	989	946
25	312	902	464
26	1,729	2,420	2,242
TOTAL	**19,315**	**33,423**	**25,202**
EPZ Population Growth:		**2000-2010**	**30.48%**
EPZ Population Difference:		**2008-2010**	**-24.60%**

Notes: 1 - 2008 COLA ETE – Resident address points within each county (except Caroline County) were provided by VDEM. Average household size from telephone survey (2.57) was used to determine 2008 EPZ population. 2000 Census projected to 2008 using county growth rate was used for Caroline County.

Table 6-1. Description of Evacuation Regions

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R01	2-Mile Radius	2- Mile Radius					x		x	x	x																
R02	5-Mile Radius	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R03	Full EPZ	Full EPZ	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Evacuate 2-Mile Radius and Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R04	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R05	NE	34° - 56°					x		x	x	x	x	x	x													
R06	ENE, E	57° - 101°					x		x	x	x	x	x														
R07	ESE	102° - 123°					x		x	x	x	x														x	
R08	SE	124° - 146°					x	x	x	x	x	x														x	
R09	SSE, S	147° - 191°					x	x	x	x	x															x	
R10	SSW	192° - 213°					x	x	x	x	x																
R11	SW	214° - 236°			x		x	x	x	x	x																
R12	WSW	237° - 258°			x		x		x	x	x																
R13	W	259°- 281°			x		x		x	x	x					x											
R14	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R15	NNW	327° - 349°					x		x	x	x			x	x	x											
Evacuate 5-Mile Radius and Downwind to the EPZ Boundary																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R16	N	349° - 11°			x		x	x	x	x	x	x	x	x	x	x			x	x	x					x	
R17	NNE	12° - 33°			x		x	x	x	x	x	x	x	x	x	x			x	x	x	x				x	
R18	NE	34° - 56°			x		x	x	x	x	x	x	x	x	x	x				x	x	x				x	
R19	ENE	57° - 78°			x		x	x	x	x	x	x	x	x	x	x					x	x	x			x	
R20	E	79° - 101°			x		x	x	x	x	x	x	x	x	x	x						x	x	x		x	
R21	ESE	102° - 123°			x		x	x	x	x	x	x	x	x	x	x						x	x	x	x	x	x
R22	SE	124° - 146°			x		x	x	x	x	x	x	x	x	x	x							x	x	x	x	x
R23	SSE, S	147° - 191°			x	x	x	x	x	x	x	x	x	x	x	x									x	x	x
R24	SSW	192° - 213°		x	x	x	x	x	x	x	x	x	x	x	x	x										x	x

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R25	SW, WSW	214° - 258°	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x									x	
R26	W	259° - 281°	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R27	WNW, NW	282° - 326°			x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R28	NNW	327° - 349°			x		x	x	x	x	x	x	x	x	x	x		x	x	x						x	
Staged Evacuation - 2-Mile Radius Evacuates, then Evacuate Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R29	-	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R30	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R31	NE	34° - 56°					x		x	x	x	x	x	x													
R32	ENE, E	57° - 101°					x		x	x	x	x	x														
R33	ESE	102° - 123°					x		x	x	x	x														x	
R34	SE	124° - 146°					x	x	x	x	x	x														x	
R35	SSE, S	147° - 191°					x	x	x	x	x															x	
R36	SSW	192° - 213°					x	x	x	x	x																
R37	SW	214° - 236°			x		x	x	x	x	x																
R38	WSW	237° - 258°			x		x		x	x	x																
R39	W	259°- 281°			x		x		x	x	x					x											
R40	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R41	NNW	327° - 349°					x		x	x	x			x	x	x											
Shelter-in-Place until 90% ETE for R01, then Evacuate				PAZ Shelter-in-Place											PAZ Evacuate												

Table 6-2. Evacuation Scenario Definitions

Scenario	Season[1]	Day of Week	Time of Day	Weather	Special
1	Summer	Midweek	Midday	Good	None
2	Summer	Midweek	Midday	Rain	None
3	Summer	Weekend	Midday	Good	None
4	Summer	Weekend	Midday	Rain	None
5	Summer	Midweek, Weekend	Evening	Good	None
6	Winter	Midweek	Midday	Good	None
7	Winter	Midweek	Midday	Rain	None
8	Winter	Midweek	Midday	Snow	None
9	Winter	Weekend	Midday	Good	None
10	Winter	Weekend	Midday	Rain	None
11	Winter	Weekend	Midday	Snow	None
12	Winter	Midweek, Weekend	Evening	Good	None
13	Winter	Weekend	Midday	Good	Kinetic Triathlon at Lake Anna State park
14	Summer	Midweek	Midday	Good	Roadway Impact – One Segment of US-522 NB will be Closed

[1] Winter means that school is in session (also applies to spring and autumn). Summer means that school is not in session.

Table 7-1. Time to Clear the Indicated Area of *90* Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:30
R02	2:25	2:25	1:50	1:50	1:50	2:30	2:35	3:25	1:50	1:50	2:55	1:55	1:50	2:30
R03	2:35	2:35	2:00	2:00	2:00	2:40	2:40	3:30	2:00	2:00	3:05	2:00	2:00	2:35
2-Mile Region and Keyhole to 5 Miles														
R04	2:20	2:20	1:45	1:45	1:45	2:30	2:30	3:15	1:50	1:50	2:55	1:50	1:50	2:20
R05	2:25	2:25	1:50	1:50	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R07	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:25
R08	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:15	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R10	2:15	2:15	1:50	1:50	1:50	2:20	2:20	3:05	1:50	1:50	2:50	1:50	1:50	2:20
R11	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:15	2:20	1:50	1:50	1:50	2:20	2:25	3:10	1:50	1:50	2:50	1:50	1:50	2:20
R13	2:20	2:20	1:45	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R14	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
R15	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
5-Mile Region and Keyhole to EPZ Boundary														
R16	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R17	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R18	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R19	2:30	2:35	1:55	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R20	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R21	2:35	2:35	2:00	2:05	2:05	2:40	2:40	3:30	2:00	2:00	3:00	2:00	2:00	2:35
R22	2:30	2:35	2:00	2:00	2:05	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R23	2:30	2:30	2:00	2:00	2:00	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R24	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R25	2:30	2:30	1:55	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R26	2:30	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R27	2:25	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
R28	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:10	2:15	3:30	2:10	2:10	2:55
R30	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R31	2:55	2:55	2:15	2:15	2:15	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R32	2:50	2:50	2:10	2:10	2:10	2:50	2:55	3:40	2:10	2:10	3:25	2:10	2:10	2:50
R33	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:25	2:05	2:05	2:50
R34	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R35	2:45	2:45	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:10	3:25	2:05	2:05	2:50
R36	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:30	2:05	2:05	3:20	2:05	2:05	2:45
R37	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R38	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:35	2:05	2:05	3:20	2:05	2:05	2:45
R39	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R40	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R41	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:05	3:25	2:05	2:05	2:50

Table 7-2. Time to Clear the Indicated Area of _100_ Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R03	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
2-Mile Region and Keyhole to 5 Miles														
R04	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R05	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R06	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R07	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R08	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R09	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R10	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R11	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R12	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R13	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R14	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R15	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
5-Mile Region and Keyhole to EPZ Boundary														
R16	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R17	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R18	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R19	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R20	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R21	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R22	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R23	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R24	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R25	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R26	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R27	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R28	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R30	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R31	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R32	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R33	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R34	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R35	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R36	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R37	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R38	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R39	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R40	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R41	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35

Table 7-3. Time to Clear 90 Percent of the 2-Mile Region

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R02	2:25	2:25	1:45	1:50	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R05	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R07	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R08	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R10	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R11	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R13	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R14	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R15	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45
R30	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R31	2:40	2:40	1:55	1:55	1:55	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R32	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R33	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R34	2:40	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R35	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R36	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R37	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R38	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R39	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R40	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R41	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40

Table 7-4. Time to Clear 100 Percent of the 2-Mile Region

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R05	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R06	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R07	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R08	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R09	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R10	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R11	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R12	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R13	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R14	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R15	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R30	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R31	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R32	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R33	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R34	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R35	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R36	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R37	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R38	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R39	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R40	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R41	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

Table 8-7. School Evacuation Time Estimates – Good Weather

School	Driver Mobilization Time (min)	Loading Time (min)	Dist. To EPZ Bdry (mi)	Average Speed (mph)	Travel Time to EPZ Bdry (min)	ETE (hr:min)	Dist. EPZ Bdry to EAC (mi.)	Travel Time from EPZ Bdry to EAC (min)	ETE to EAC (hr:min)
LOUISA COUNTY SCHOOLS									
Louisa County High School	90	15	3.7	45.0	5	**1:50**	8.3	11	**2:05**
Louisa County Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Mineral Christian Preschool	90	15	4.8	45.0	7	**1:55**	8.3	11	**2:10**
Thomas Jefferson Elementary School	90	15	1.5	45.0	3	**1:50**	8.6	11	**2:05**
SPOTSYLVANIA COUNTY SCHOOLS									
Berkeley Elementary School	90	15	2.1	44.7	3	**1:50**	8.0	11	**2:05**
Livingston Elementary School	90	15	9.1	45.0	13	**2:00**	8.3	11	**2:10**
Post Oak Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Spotsylvania High School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
Spotsylvania High School - Governor's School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
					Maximum for EPZ:	**2:00**		**Maximum:**	**2:10**
					Average for EPZ:	**1:55**		**Average:**	**2:10**

Table 8-11. Transit-Dependent Evacuation Time Estimates – Good Weather

Route Number	Bus Number	One-Wave: Mobilization (min)	Route Length (miles)	Speed (mph)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)	Distance to EAC (miles)	Two-Wave: Travel Time to EAC (min)	Unload (min)	Driver Rest (min)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)
1	1	105	12.6	45.0	17	30	**2:35**	8.2	11	5	10	41	30	**4:15**
2	1	105	17.4	38.9	27	30	**2:45**	8.2	11	5	10	50	30	**4:35**
3	1	105	20.2	44.6	27	30	**2:45**	8.2	11	5	10	51	30	**4:35**
4	1	105	15.3	45.0	20	30	**2:35**	8.2	11	5	10	45	30	**4:20**
5	1	105	13.0	45.0	17	30	**2:35**	8.9	12	5	10	43	30	**4:15**
6	1	105	25.5	45.0	34	30	**2:50**	8.5	11	5	10	59	30	**4:50**
7	1	105	19.8	45.0	26	30	**2:45**	12.1	16	5	10	56	30	**4:45**
8	1	105	32.2	45.0	43	30	**3:00**	8.2	11	5	10	67	30	**5:05**
9	1	105	22.8	45.0	30	30	**2:45**	8.2	11	5	10	55	30	**4:40**
10	1	105	26.3	40.2	39	30	**2:55**	8.2	11	5	10	61	30	**4:55**
11	1	105	17.3	45.0	23	30	**2:40**	9.5	13	5	10	49	30	**4:30**
12	1	105	27.6	45.0	37	30	**2:55**	8.3	11	5	10	61	30	**4:55**
13	1	105	17.0	44.8	23	30	**2:40**	8.3	11	5	10	47	30	**4:25**
14	1	105	36.6	45.0	49	30	**3:05**	13.5	18	5	10	80	30	**5:30**
15	1	105	17.5	45.0	23	30	**2:40**	8.3	11	5	10	48	30	**4:25**
16	1	105	23.2	44.5	31	30	**2:50**	7.8	10	5	10	55	30	**4:45**
17	1	105	9.5	43.0	13	30	**2:30**	7.8	10	5	10	36	30	**4:05**
18	1	105	30.5	45.0	41	30	**3:00**	13.5	18	5	10	72	30	**5:15**
19	1	105	18.5	45.0	25	30	**2:40**	13.5	18	5	10	56	30	**4:40**
20	1	105	29.2	45.0	39	30	**2:55**	13.5	18	5	10	70	30	**5:10**
21	1	105	10.7	45.0	14	30	**2:30**	14.8	20	5	10	47	30	**4:25**
22	1	105	5.1	45.0	7	30	**2:25**	12.6	17	5	10	31	30	**4:00**
23	1	105	7.7	45.0	10	30	**2:25**	13.4	18	5	10	38	30	**4:10**
24	1	105	8.0	35.5	13	30	**2:30**	13.4	18	5	10	41	30	**4:15**
25	1	105	7.2	45.0	10	30	**2:25**	12.7	17	5	10	36	30	**4:05**
						Maximum ETE:	**3:05**						**Maximum ETE:**	**5:30**
						Average ETE:	**2:45**						**Average ETE:**	**4:35**

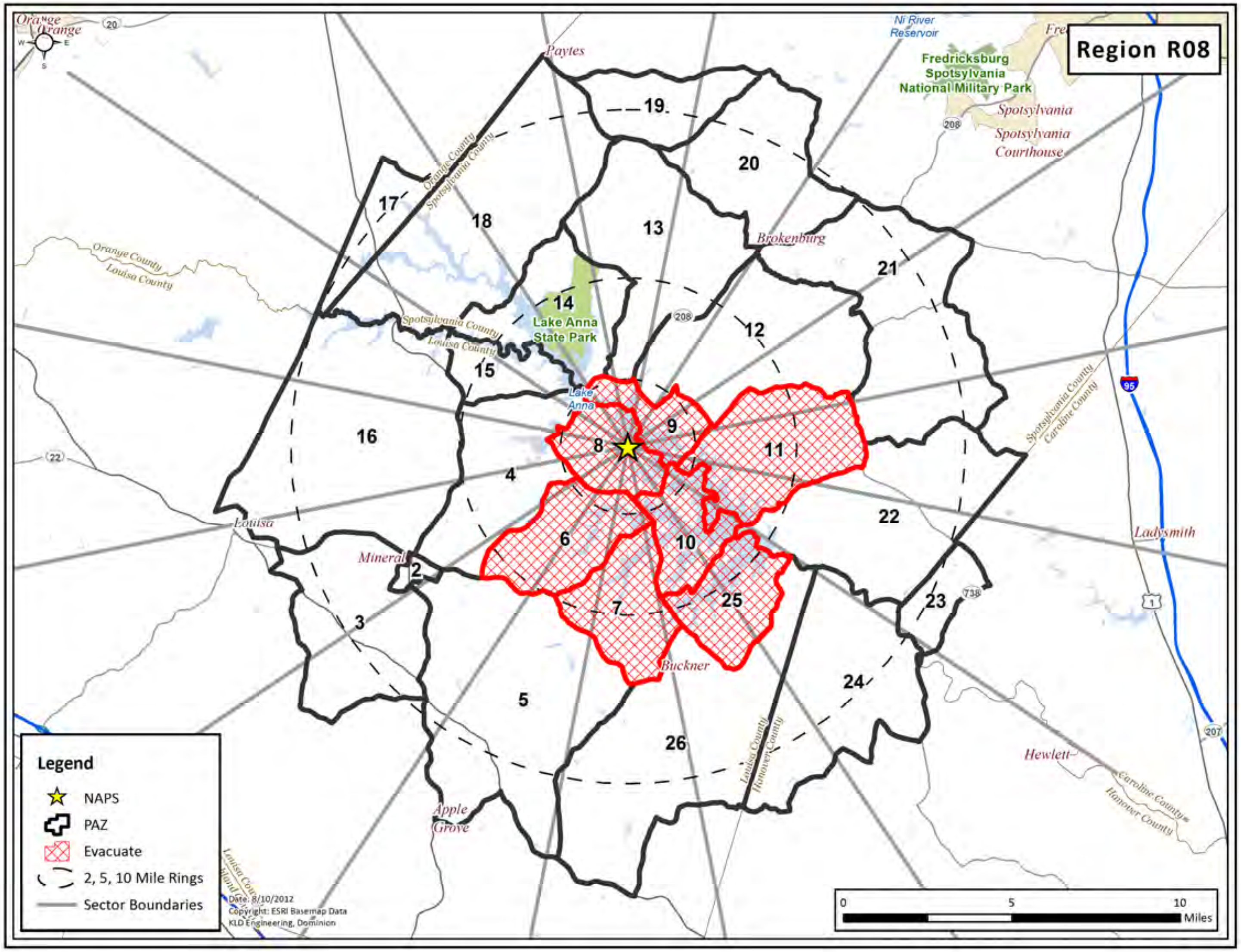


Figure H-8. Region R08

Appendix 5–Implementing Procedures – Topical List

Emergency plan implementing procedures address a range of actions needed to implement the contents of this emergency plan. The emergency plan implementing procedures address, at a minimum, the following topics, including parenthetical references to the affected sections of this plan:

- Emergency Classification (II.D)
- Notifications Associated with Emergency Conditions (II.E, II.L.1)
- Emergency Communications (II.F)
- Protective Action Recommendations (II.J.7, II.J.10)
- Activation of the Emergency Response Organization (I.B)
- Site Assembly, Accountability, and Evacuation (II.J.4, II.J.5)
- Core Damage Assessment (II.I)
- Radiation Protection Under Emergency Conditions (II.K)
- Plume Tracking and Assessment of Offsite Radiological Conditions (II.I)
- Respiratory Protection and Distribution of Radioprotective Drugs (II.J.6)
- Personnel Monitoring (II.K.2, II.K.3)
- Decontamination (II.K.5, II.K.7)
- Obtaining and Analyzing High Activity Samples Under Emergency Conditions (II.I)
- Emergency Media Relations (II.G)
- Recovery and Reentry (II.M)

Additional plant procedures address various activities that are required to support the ongoing maintenance of emergency preparedness. These supporting procedures are not included within the body of the emergency plan implementing procedures. These supporting procedures address, at a minimum, the following topics, including parenthetical references to the affected sections of this plan:

- Emergency Equipment Inventory and Operational Tests (II.H.10)
- Conduct of Emergency Drills and Exercises (II.N)
- Testing of Emergency Communications Systems (II.N, II.F)
- Emergency Plan Training (II.G.5, II.O, II.P.1)
- Maintaining Emergency Preparedness (II.P)

Appendix 6–Emergency Equipment and Supplies

Dominion maintains inventories of emergency equipment and supplies for use by emergency response personnel in the ERFs and by Dominion's offsite field monitoring teams. The actual inventories are based on the activities that occur in, or are dispatched from, the affected facility. Actual inventories are established in inventory lists in accordance with plant procedures. Emergency kit inventories typically include the following:

- Radiation survey instrument(s)
- Surface contamination control and survey supplies
- Air sampling equipment and sampling media
- Scaler(s) or other appropriate radio-analytical counting instrument(s)
- Protective clothing
- Contamination control and decontamination supplies
- Respiratory protection equipment
- Radiological control posting and warning supplies
- Personnel monitoring equipment (record and instantaneous reading dosimeters)
- Radioiodine blocking agent
- Emergency lighting equipment
- Appropriate maps
- Computer equipment
- Plans, procedures, and drawings
- Communications equipment
- Administrative and recordkeeping supplies
- Batteries and other expendable supplies
- First aid supplies (e.g., bandages, stretchers, splints, topical ointments)

Appendix 7–Certification Letter

COMMONWEALTH of VIRGINIA

Department of Emergency Management

MICHAEL M. CLINE
State Coordinator

JACK E. KING
Chief Deputy Coordinator

BRETT A. BURDICK
Deputy Coordinator

10501 Trade Court
Richmond, Virginia 23236-3713
(804) 897-6500
(TDD) 674-2417
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June 11, 2010

MEMORANDUM

TO: Mrs. Leslie N. Hartz
Vice President, Nuclear Support Services
Dominion Resources Services, Inc.

FROM: Signatory Agencies in Support of the Original North Anna Power Station Emergency Operations Plan, dated July 1974

SUBJECT: Combined License Application for a new nuclear generating unit at the North Anna Power Station

The below-signed state agencies and localities have reviewed the emergency plan supporting the revised Combined License Application for a new nuclear generating unit at the North Anna Power Station. This memorandum updates correspondence filed with Dominion Resources Services, Inc., dated during the period of August-September 2007. The organizations severally certify its commitment that:

- Proposed emergency plans are practicable;
- Virginia Department of Emergency Management is committed to participating in further development of the plans, including any required field demonstrations; and
- Virginia Department of Emergency Management is committed to executing their responsibilities under the plans in the event of an emergency.

Furthermore, the organizations concur with the proposed emergency classification system, initiating conditions, and emergency action levels described in the Combined License Application Emergency Plan and evacuation time estimates.

It is with joint understanding that the specific nature of arrangements in support of emergency preparedness for operation of the proposed new nuclear unit will be clearly established in a properly executed and binding letter of agreement that will be included in the North Anna Unit 3 Combined License Application Emergency Plan if and when Dominion Energy proceeds with construction and operation of this nuclear facility.

We, the below signed, look forward to continuing our partnership in these efforts:

Karen Remley, M.D.
State Health Commissioner
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Nancy.glasheen@vdh.virginia.gov

Date: 6/11/10

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Date: 11 Jun 10

On Behalf of Col. Flaherty.
Captain Steven L. Chumley

Colonel W. S. (Steve) Flaherty
Superintendent, Virginia Department of State Police
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STEVEN.CHUMLEY@VSP.VIRGINIA.GOV
DIV. 1 COMMANDER

Date: 6/11/10

~~Robert W. Duncan~~ Dabney W. Watts
Director, Virginia Department of Game and Inland Fisheries, Law Enforcement Division
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Date: 06-11-2010

V.P. Support Services
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~~Chief Executive Officer, Virginia Commonwealth University Medical Center~~
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Date: 6/15/2010

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Date: 6/11/2010

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Date: 6/15/10

Appendix 8–Cross-Reference to Regulations, Guidance, and State and Local Plans

Note: To a limited extent, certain details of the Commonwealth and risk jurisdiction plans may be specific to Unit 3. Such details will be developed at a later date consistent with the commitments outlined in the certification letter provided in Appendix 7 of this plan.

Requirement	Corresponding COL Emergency Plan Provision
10 CFR 50.47(b)(1)	II.A, II.B, II.C
10 CFR 50.47(b)(2)	II.A, II.B, II.C, II.E, II.F
10 CFR 50.47(b)(3)	II.A, II.B, II.C, II.H
10 CFR 50.47(b)(4)	II.D, App. 1
10 CFR 50.47(b)(5)	II.E, II.F, II.J
10 CFR 50.47(b)(6)	II.E, II.F, II.J
10 CFR 50.47(b)(7)	II.G
10 CFR 50.47(b)(8)	II.H
10 CFR 50.47(b)(9)	II.H, II.I
10 CFR 50.47(b)(10)	II.J, II.K
10 CFR 50.47(b)(11)	II.J, II.K
10 CFR 50.47(b)(12)	II.L
10 CFR 50.47(b)(13)	II.M
10 CFR 50.47(b)(14)	II.N
10 CFR 50.47(b)(15)	II.O
10 CFR 50.47(b)(16)	II.P
10 CFR 50.72(a)(3)	II.E.1
10 CFR 50.72(a)(4)	II.F.1.f
10 CFR 50.72(c)(3)	II.E.4
10 CFR 50 App E.IV.1-7	COL Emergency Plan, including App. 4 and Evacuation Time Estimate, II.J, II.P
10 CFR 50 App E.IV.A	II.A, II.B, II.C, II.E, II.F, II.J, II.K, II.L
10 CFR 50 App E.IV.B	II.D, II.H, II.I, App. 1
10 CFR 50 App E.IV.C	II.A, II.D, II.E. II.F, App. 1
10 CFR 50 App E.IV.D	II.A, II.E, II.F, II.G, App. 3
10 CFR 50 App E.IV.E	II.B, II.F, II.H, II.I, II.L, II.N, App. 2, App. 6
10 CFR 50 App E.IV.F	II.N, II.O
10 CFR 50 App E.IV.G	II.P

Requirement	Corresponding COL Emergency Plan Provision
10 CFR 50 App E.IV.H	II.M
10 CFR 50 App E.IV.I	II.J

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
A.1.a	Plan §II.A.1.a	Plan §VII, App. 3	Plan §VII	Plan §VII	Plan §VII	Plan §VII	Plan §VII
A.1.b	Plan §II.A.1.b	Plan §VIII, App. 3	Plan §VIII	Plan §VIII	Plan §V.II	Plan §V.II	Plan §VIII
A.1.c	Plan §II.A.1.c	App. 3	Plan Att. 12 & 13	Plan Att. 12 & 13	Plan Att. 12 & 13	Plan Att. 12 & 13	Plan Att. 12 & 13
A.1.d	Plan §II.A.1.d	Plan §VII.C	Plan §VII.A	Plan §VII.A	Plan §VII.A	Plan §VII.A	Plan §VII.A
A.1.e	Plan §II.A.1.e	App. 10 §II.A	Plan §§VII.A, IX.A., IX.B, ESF #5	Plan §§VII.A, IX.A., IX.B, ESF #5	Plan §VII.A, App. 5	Plan §VII.A, App. 5	Plan §§VII.A, IX.A., IX.B, ESF #5
A.2.a		App. 2 Tab A	Plan Att. 13	Plan Att. 13	Plan Att. 13	Plan Att. 13	Plan Att. 13
A.2.b		Plan §I	Plan §I.A	Plan §I.A	Plan §I	Plan §I	Plan §I.A
A.3	Plan §II.A.3	Plan Att. 1	Plan Att. 14	Plan Att. 14	Plan Att. 14	Plan Att. 14	Plan Att. 14
A.4	Plan §II.A.4	App. 1 §C	Plan §VII	Plan §VII	Plan §V.II	Plan §V.II	Plan §VII
B.1	Plan §II.B.1						
B.2	Plan §II.B.2						
B.3	Plan §II.B.3						
B.4	Plan §II.B.4						
B.5	Plan §II.B.5						
B.6	Plan §II.B.6						
B.7	Plan §II.B.7						
B.7	Plan §II.B.7						
B.7	Plan §II.B.7						

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
B.7	Plan §II.B.7						
B.7	Plan §II.B.7						
B.8	Plan §II.B.8						
B.9	Plan §II.B.9						
C.1.a	Plan §II.C.1.a	App. 2 §1.E					
C.1.b	Plan §II.C.1.b	App. 2 §II					
C.1.c	Plan §II.C.1.c	App. 2 Tab B	Plan §IX.A	Plan §IX.A	Plan §IX.A	Plan §IX.A	Plan §IX.A
C.2.a		Plan §VII.D, App. 1 §D.3, App. 2 §I.A.2	not applicable	not applicable	not applicable	not applicable	not applicable
C.2.b	Plan §II.C.2.b						
C.3	Plan §II.C.3	App. 6 §II.C.3					
C.4	Plan §II.C.4, App. 7	App. 6	Plan Att. 14	Plan Att. 14	Published separately	Published separately	Plan Att. 14
C.5	Not used						
C.6	Reserved for future revision per 10 CFR 50, Appendix E, IV.A.7 implementation schedule						
D.1	Plan §II.D.1, App. 1						
D.2	Plan §II.D.2, App. 1						
D.3		App. 5	Plan §VIII.A	Plan §VIII.A	Plan §VIII.A	Plan §VIII.A	Plan §VIII.A

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
D.4		Plan §VIII.B, App. 5	Plan §VIII.E	Plan §VIII.E	Plan §VIII.E	Plan §VIII.E	Plan §VIII.E
E.1	Plan §II.E.1	App. 4	Plan §VIII.C, ESF #2 & #5	Plan §VIII.C, ESF #2 & #5	Plan §VIII.C, App. 1 & 5	Plan §VIII.C, App. 1 & 5	Plan §VIII.C, ESF #2 & #5
E.2	Plan §II.E.2	Plan §VIII.C, App. 1 Tab A, App. 4	Plan §VIII.C, ESF #2 & #5	Plan §VIII.C, ESF #2 & #5	Plan §VIII.C, App. 1 & 5	Plan §VIII.C, App. 1 & 5	Plan §VIII.C, ESF #2 & #5
E.3	Plan §II.E.3						
E.4	Plan §II.E.4						
E.4.a	Plan §II.E.4						
E.4.b	Plan §II.E.4						
E.4.c	Plan §II.E.4						
E.4.d	Plan §II.E.4						
E.4.e	Plan §II.E.4						
E.4.f	Plan §II.E.4						
E.4.g	Plan §II.E.4						
E.4.h	Plan §II.E.4						
E.4.i	Plan §II.E.4						
E.4.j	Plan §II.E.4						
E.4.k	Plan §II.E.4						
E.4.l	Plan §II.E.4						

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
E.4.m	Plan §II.E.4						
E.4.n	Plan §II.E.4						
E.5		Plan §IX.C, App. 9, Annex M Tab A & B	Plan §§VIII.D & IX.C, ESF #2 & #5	Plan §§VIII.D & IX.C, ESF #2 & #5	Plan §VIII.D, App. 2 & 5	Plan §VIII.D, App. 2 & 5	Plan §§VIII.D & IX.C, ESF #2 & #5
E.6	Plan §II.E.6	Plan §IX.C, App. 4 §II.B	Plan §§VIII.D & IX.C, ESF #2	Plan §§VIII.D & IX.C, ESF #2	Plan §VIII.D, App. 2 & 5	Plan §VIII.D, App. 2 & 5	Plan §§VIII.D & IX.C, ESF #2
E.7	Plan §II.E.7	Annex M Tab A Att. 1	Plan §IX.C, ESF #2	Plan §IX.C, ESF #2	Plan §IX.C, App. 2	Plan §IX.C, App. 2	Plan §IX.C, ESF #2
F.1.a	Plan §II.F.1.a	App. 10 §II	Plan §IX.B	Plan §IX.B	Plan §VII, App. 5	Plan §VII, App. 5	Plan §IX.B
F.1.b	Plan §II.F.1.b	App. 10 §IV.H	Plan §IX.B, ESF #5	Plan §IX.B, ESF #5	Plan §IX.B.	Plan §IX.B.	Plan §IX.B, ESF #5
F.1.c	Plan §II.F.1.c	App. 10 §IV.I	See COVRERP	See COVRERP	See COVRERP	See COVRERP	See COVRERP
F.1.d	Plan §II.F.1.d	App. 10 §II	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B
F.1.e	Plan §II.F.1.e	App. 10 §II	Plan §VIII.C	Plan §VIII.C	Plan §VIII.C, App. 5	Plan §VIII.C, App. 5	Plan §VIII.C
F.1.f	Plan §II.F.1.						
F.2	Plan §II.F.2	App. 10 §III.E	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B
F.3	Plan §II.F.3	App. 10, App. 13 §II.C.1	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B	Plan §IX.B
G.1	Plan §II.G.1	App. 10 §II.A.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1
G.2	Plan §II.G.2	App. 9 §II.A	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
G.3.a	Plan §II.G.3.a	App. 9 §III.A	Plan §IX.C.2	Plan §IX.C.2	Plan §IX.C.2	Plan §IX.C.2	Plan §IX.C.2
G.3.b	Plan §II.G.3.b						
G.4.a	Plan §II.G.4.a	App. 9 §III	Plan §IX.C.2, ESF #5	Plan §IX.C.2, ESF #5	Plan §IX.C.2, App. 2	Plan §IX.C.2, App. 2	Plan §IX.C.2, ESF #5
G.4.b	Plan §II.G.4.b	App. 9 §III.A	ESF #5	ESF #5	Plan §IX.C.2, App. 2	Plan §IX.C.2, App. 2	ESF #5
G.4.c	Plan §II.G.4.c	App. 9 §III	Plan §IX.C.2, ESF #5	Plan §IX.C.2, ESF #5	Plan §IX.C.2, App. 2	Plan §IX.C.2, App. 2	Plan §IX.C.2, ESF #5
G.5	Plan §II.G.5	App. 9, Annex M	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1	Plan §IX.C.1
H.1	Plan §II.H.1						
H.2	Plan §II.H.2						
H.3		Plan §VII, App. 1, App. 4	Plan §IX.A, App. 1	Plan §IX.A, App. 1	Plan §IX.A, App. 2	Plan §IX.A, App. 2	Plan §IX.A, App. 1
H.4	Plan §II.H.4	App. 1 §C	Plan §IX.A, ESF #5	Plan §IX.A, ESF #5	Plan §IX.A, App. 1 & 5	Plan §IX.A, App. 1 & 5	Plan §IX.A, ESF #5
H.5	Plan §II.H.5						
H.5.a	Plan §II.H.5.a						
H.5.b	Plan §II.H.5.b						
H.5.c	Plan §II.H.5.c						
H.5.d	Plan §II.H.5.d						
H.6.a	Plan §II.H.6.a						
H.6.b	Plan §II.H.6.b						

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
H.6.c	Plan §II.H.6.c						
H.7	Plan §II.H.7, App. 6	App. 7 §III & Tab E	Plan §VII.B	Plan §VII.B	Plan §VIII.B, App. 6	Plan §VIII.B, App. 6	Plan §VII.B
H.8	Plan §II.H.8, App. 2						
H.9	Plan §II.H.9, App. 2						
H.10	Plan §II.H.10, App. 6	App. 7 §III.A.1 & Tab E	Plan §VII.A.1	Plan §VII.A.1	Plan §VII.A.1	Plan §VII.A.1	Plan §VII.A.1
H.11	Plan §II.H.11, App. 6	App. 7	ESF #6 & #7 & #8	ESF #6 & #7 & #8	App. 3 & 6	App. 3 & 6	ESF #6 & #7 & #8
H.12	Plan §II.H.12	App. 6 §II.C	Plan §VIII.B, ESF #10	Plan §VIII.B, ESF #10	Plan §VIII.B, App. 6	Plan §VIII.B, App. 6	Plan §VIII.B, ESF #10
I.1	Plan §II.I.1						
I.2	Plan §II.I.2						
I.3.a	Plan §II.I.3.a						
I.3.b	Plan §II.I.3.b						
I.4	Plan §II.I.4						
I.5	Plan §II.I.5						
I.6	Plan §II.I.6						
I.7	Plan §II.I.7, App. 6	App. 6 §II.C	Plan §VIII.B, ESF #10	Plan §VIII.B, ESF #10	Plan §VIII.B, App. 6	Plan §VIII.B, App. 6	Plan §VIII.B, ESF #10

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
I.8	Plan §II.I.8	App. 6 §II.C, App. 7 §II.B	ESF #10	ESF #10	App. 6	App. 6	ESF #10
I.9	Plan §II.I.9	App. 6 §II.C.3.b					
I.10	Plan §II.I.10, App. 2	Bureau of Radiological Health SOP					
I.11		App. 6 §II.C.3					
J.1.a	Plan §II.J.1						
J.1.b	Plan §II.J.1						
J.1.c	Plan §II.J.1						
J.1.d	Plan §II.J.1						
J.2	Plan §II.J.2	App. 5 Tab A, App. 5 Tab B Att. 6	Not applicable in Caroline County.	Not applicable in Hanover County.	Not applicable in Louisa County	Not applicable in Orange County	Not applicable in Spotsylvania County.
J.3	Plan §II.J.3						
J.4	Plan §II.J.4						
J.5	Plan §II.J.5						
J.6.a	Plan §II.J.6.a						
J.6.b	Plan §II.J.6.b						
J.6.c	Plan §II.J.6.c						
J.7	Plan §II.J.7, App. 2						

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
J.8	Plan §II.J.8, App. 4						
J.9		App. 6 §II.C	Plan §§V.D & VIII.F	Plan §§V.D & VIII.F	Plan §§V.D & VIII.F	Plan §§V.D & VIII.F	Plan §§V.D & VIII.F
J.10.a	Plan §II.J.10.a	App. 5 Tab B Att. 6	Plan Att. 10 & 11, ESF #6 & #10	Plan Att. 10 & 11, ESF #6 & #10	Plan Att. 10, App. 4 & 6	Plan Att. 10, App. 4 & 6	Plan Att. 10 & 11, ESF #6 & #10
J.10.b	Plan §II.J.10.b	App. 5 Tab B Att. 6	Plan Att. 6-9	Plan Att. 6-9	Plan Att. 9 & 10	Plan Att. 9 & 10	Plan Att. 6-9
J.10.c	Plan §II.J.10.c, App. 3	App. 4 §II.B	Plan §VIII.D, ESF #2	Plan §VIII.D, ESF #2	Plan §VIII.D, App. 4	Plan §VIII.D, App. 4	Plan §VIII.D, ESF #2
J.10.d		App. 4 §II.B.3, App. 5	Plan §§V.D & VII.A.4, ESF #6 & 10	Plan §§V.D & VII.A.4, ESF #6 & 10	Plan §§V.D & VII.A.4, App. 4	Plan §§V.D & VII.A.4, App. 4	Plan §§V.D & VII.A.4, ESF #6 & 10
J.10.e		App. 8	Plan §V.D, ESF #6 & 10	Plan §V.D, ESF #6 & 10	Plan §V.D, App. 3, App. 6	Plan §V.D, App. 3, App. 6	Plan §V.D, ESF #6 & 10
J.10.f		App. 8	not applicable	not applicable	not applicable	not applicable	not applicable
J.10.g		App. 5	Plan §V.D, ESF #13	Plan §V.D, ESF #13	Plan §V.D, App. 3	Plan §V.D, App. 3	Plan §V.D, ESF #13
J.10.h		App. 5, App. 11	Plan §V.D, ESF #6	Plan §V.D, ESF #6	Plan §V.D, App. 3	Plan §V.D, App. 3	Plan §V.D, ESF #6
J.10.i		App. 5 Tab B Att. 6	Plan Att. 5 & 10	Plan Att. 5 & 10	Plan Att. 5 & 10	Plan Att. 5 & 10	Plan Att. 5 & 10
J.10.j		Annex A Tab C	Plan §§V.D & VII.A.2, ESF #13	Plan §§V.D & VII.A.2, ESF #13	Plan §§V.D & VII.A.2, App. 4	Plan §§V.D & VII.A.2, App. 4	Plan §§V.D & VII.A.2, ESF #13

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
J.10.k		App. 12 §III.A	Plan §VII, ESF #13	Plan §VII, ESF #13	Plan §V.D, App. 4	Plan §V.D, App. 4	Plan §VII, ESF #13
J.10.l		App. 5 Tab B Att. 6	Plan Att. 5 & 10	Plan Att. 5 & 10	Plan Att. 11	Plan Att. 11	Plan Att. 5 & 10
J.10.m	Plan §II.J.10.m	App. 7					
J.11		App. 7 (Also see Maryland Plan)					
J.12		App. 11	Plan §V.D, ESF #6	Plan §V.D, ESF #6	Plan §V.D, App. 3	Plan §V.D, App. 3	Plan §V.D, ESF #6
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.1	Plan §II.K.1						
K.2	Plan §II.K.2						
K.3.a	Plan §II.K.3.a	App. 7 §II & III	Plan §§VIII.B & VIII.F, ESF #10	Plan §§VIII.B & VIII.F, ESF #10	Plan §§VIII.B & VIII.F, App. 6	Plan §§VIII.B & VIII.F, App. 6	Plan §§VIII.B & VIII.F, ESF #10
K.3.b	Plan §II.K.3.b	App. 7 Tabs C & G	Plan §VIII.F, ESF #10	Plan §VIII.F, ESF #10	Plan §VIII.F, App. 6	Plan §VIII.F, App. 6	Plan §VIII.F, ESF #10

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
K.4		App. 7	Plan §VIII.F, ESF #10	Plan §VIII.F, ESF #10	Plan §VIII.F, App. 6	Plan §VIII.F, App. 6	Plan §VIII.F, ESF #10
K.5.a	Plan §II.K.5.a	App. 7 §II.B.3	ESF #6	ESF #6	App. 3 & 6	App. 3 & 6	ESF #6
K.5.b	Plan §II.K.5.b	App. 7 Tab D, App. 11	ESF #6 & #10	ESF #6 & #10	App. 3 & 9	App. 3 & 9	ESF #6 & #10
K.6.a	Plan §II.K.6.a						
K.6.b	Plan §II.K.6.b						
K.6.c	Plan §II.K.6.c						
K.7	Plan §II.K.7						
L.1	Plan §II.L.1	Annex H Tab A	ESF #6	ESF #6	App. 3 & 8 & 9	App. 3 & 8 & 9	ESF #6
L.2	Plan §II.L.2						
L.3		Annex H Tab A					
L.4	Plan §II.L.4	Annex H Tab C	ESF #6	ESF #6	App. 3 & 8	App. 3 & 8	ESF #6
M.1	Plan §II.M.1	App. 11	ESF #5	ESF #5	App. 1 & 6	App. 1 & 6	ESF #5
M.2	Plan §II.M.2						
M.3	Plan §II.M.3	App. 11					
M.4	Plan §II.M.4	App. 11					
N.1.a	Plan §II.N.1.a	App. 13	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
N.1.b	Plan §II.N.1.b	App. 13 §II	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
N.1.c	Plan §II.N.1.c	This evaluation criterion does not apply to off-site plans.					
N.2.a	Plan §II.N.2.a	App. 13 §II.C.1	Plan §XII.B.1	Plan §XII.B.1	Plan §XII.B.1	Plan §XII.B.1	Plan §XII.B.1

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
N.2.b	Plan §II.N.2.b						
N.2.c	Plan §II.N.2.c	App. 13 §II.C.2	not applicable, see COVRERP	not applicable, see COVRERP	not applicable, see COVRERP	not applicable, see COVRERP	not applicable, see COVRERP
N.2.d	Plan §II.N.2.d	App. 13 §II.C.3	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
N.2.e(1)	Plan §II.N.2.e	App. 13 §II.C.4					
N.2.e(2)	Plan §II.N.2.e						
N.3.a	Plan §II.N.3.a	App. 13 §II.D.1	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
N.3.b	Plan §II.N.3.b	App. 13 §II.D.2	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.3.c	Plan §II.N.3.c	App. 13 §II.D.3	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.3.d	Plan §II.N.3.d	App. 13 §II.D.4	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.3.e	Plan §II.N.3.e	App. 13 §II.D.5	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.3.f	Plan §II.N.3.f	App. 13 §II.D	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.4	Plan §II.N.4	App. 13 §II.A.4	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
N.5	Plan §II.N.5	App. 13 §II.A.4	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
O.1	Plan §II.O.1	App. 13 §II.E	Plan §XII.A	Plan §XII.A	Plan §XII.A	Plan §XII.A	Plan §XII.A
O.1.a	Plan §II.O.1.a						

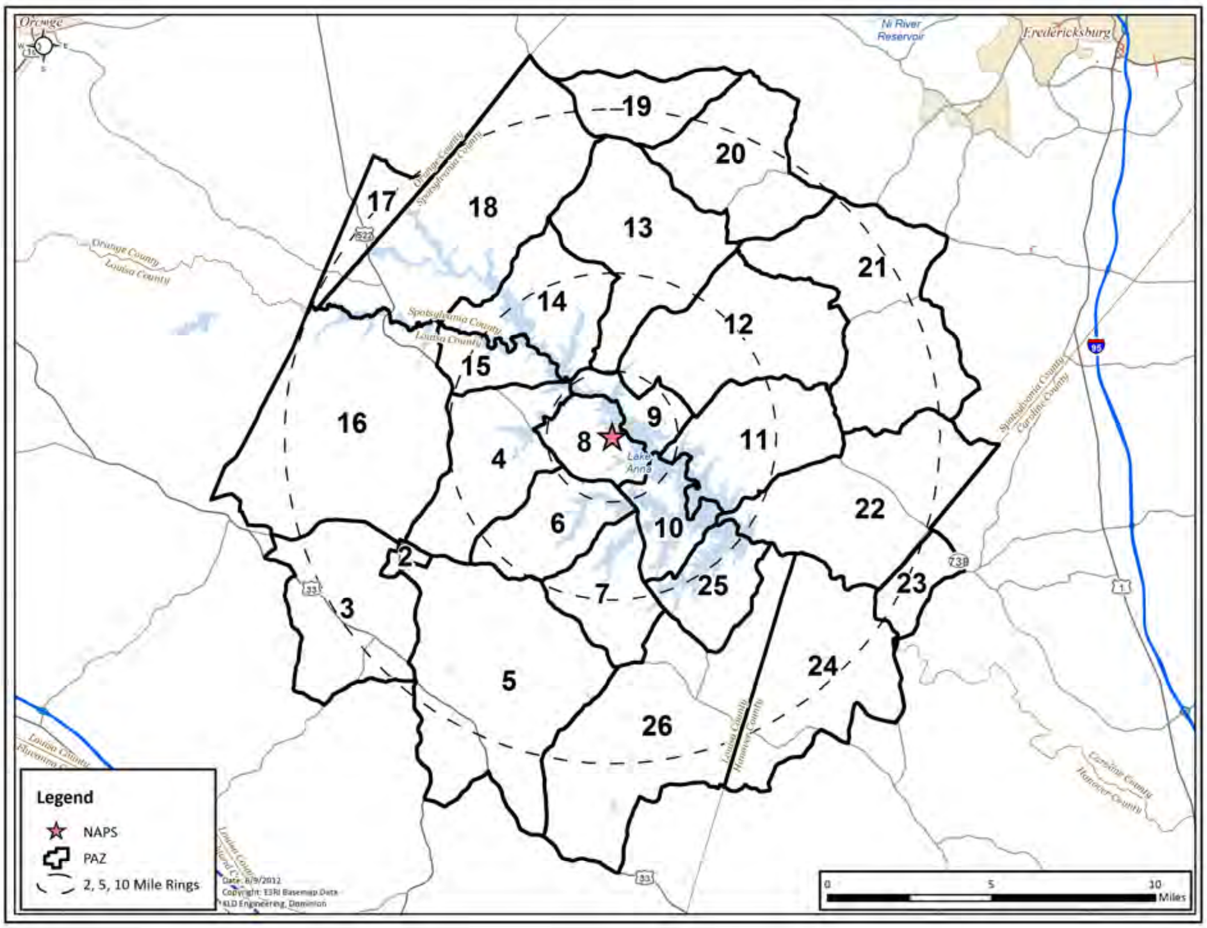
NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
O.1.b		App. 13 §II.E.1	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.2	Plan §II.O.2						
O.3	Plan §II.O.3						
O.4.a	Plan §II.O.4.a	App. 13 §II.E	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.4.b	Plan §II.O.4.b	App. 13 §II.E.2	See COVRERP	See COVRERP	See COVRERP	See COVRERP	See COVRERP
O.4.c	Plan §II.O.4.c	App. 13 §II.E.6	See COVRERP	See COVRERP	See COVRERP	See COVRERP	See COVRERP
O.4.d	Plan §II.O.4.d	App. 13 §II.E.3	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.4.e	Plan §II.O.4.e						
O.4.f	Plan §II.O.4.f	App. 13 §II.E.3	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.4.g	Plan §II.O.4.g		Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.4.h	Plan §II.O.4.h	App. 13 §II.E.3	Plan §XII	Plan §XII	Plan §XII	Plan §XII	Plan §XII
O.4.i	Plan §II.O.4.i						
O.4.j	Plan §II.O.4.j	App. 13 §II.E.4	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
O.5	Plan §II.O.5	App. 13 §§II.E.1 & 6	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP	Plan §XII, see COVRERP
P.1	Plan §II.P.1	App. 13 §§II.E.1 & 6	Plan §§VII.A & XII.A	Plan §§VII.A & XII.A	Plan §§VII.A & XII.A	Plan §§VII.A & XII.A	Plan §§VII.A & XII.A
P.2	Plan §II.P.2	Plan §VII.B, App. 2	Plan §VII	Plan §VII	Plan §VII	Plan §VII	Plan §VII
P.3	Plan §II.P.3	Plan §X.C	Plan §VII	Plan §VII	Plan §VII	Plan §VII	Plan §VII

NUREG-0654 Eval. Criterion	COL EPlan	Commonwealth of Virginia	Caroline County	Hanover County	Louisa County	Orange County	Spotsylvania County
P.4	Plan §II.P.4	Plan §X.C.1	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI
P.5	Plan §II.P.5	Plan §X.C, App. 2	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI	Plan §§VII & XI
P.6	Plan §II.P.6	Plan Att. 1	Plan §I	Plan §I	Plan §I	Plan §I	Plan §I
P.7	Plan §II.P.7, App. 5	Plan Att. (un-numbered)	Plan §XIV	Plan §XIV	Plan §XIV	Plan §XIV	Plan §XIV
P.8	Plan §II.P.8, App. 8	Plan pages i through ix	Plan pages i through xvii	Plan pages i through xvii	Plan pages i through xvii	Plan pages i through xvii	Plan pages i through xvii
P.9	Plan §II.P.9						
P.10	Plan §II.P.10	Plan §IX.B	Plan §X	Plan §X	Plan §X	Plan §X	Plan §X

KLD ENGINEERING, P.C.

North Anna Power Station

Development of Evacuation Time Estimates



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EXECUTIVE SUMMARY

This report describes the analyses undertaken and the results obtained by a study to develop Evacuation Time Estimates (ETE) for the North Anna Power Station (NAPS) located in Louisa County, Virginia. ETE are part of the required planning basis and provide Dominion and State and local governments with site-specific information needed for Protective Action decision-making.

In the performance of this effort, guidance is provided by documents published by Federal Governmental agencies. Most important of these are:

- Criteria for Development of Evacuation Time Estimate Studies, NUREG/CR-7002, November 2011.
- Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, NUREG-0654/FEMA-REP-1, Rev. 1, November 1980.
- Development of Evacuation Time Estimates for Nuclear Power Plants, NUREG/CR-6863, January 2005.
- 10CFR50, Appendix E – "Emergency Planning and Preparedness for Production and Utilization Facilities"

<u>Overview of Project Activities</u>

This project began in February, 2012 and extended over a period of 9 months. The major activities performed are briefly described in chronological sequence:

- Attended "kick-off" meetings with Dominion personnel and emergency management personnel representing state and county governments.
- Accessed U.S. Census Bureau data files for the year 2010. Studied Geographical Information Systems (GIS) maps of the area in the vicinity of the NAPS, then conducted a detailed field survey of the highway network.
- Synthesized this information to create an analysis network representing the highway system topology and capacities within the Emergency Planning Zone (EPZ), plus a Shadow Region covering the region between the EPZ boundary and approximately 15 miles radially from the plant.
- Designed and sponsored a telephone survey of residents within the EPZ to gather focused data needed for this ETE study that were not contained within the census database. The survey instrument was reviewed and modified by the licensee and offsite response organization (ORO) personnel prior to the survey (survey from the 2007 COLA was used since EPZ demographics did not significantly change).
- Counties provided school and transportation resources data. Data for transient facilities

was collected through phone calls to specific facilities.

- The traffic demand and trip-generation rates of evacuating vehicles were estimated from the gathered data. The trip generation rates reflected the estimated mobilization time (i.e., the time required by evacuees to prepare for the evacuation trip) computed using the results of the telephone survey of EPZ residents.
- Following federal guidelines, the EPZ is subdivided into 25 Protective Action Zones (PAZ). These PAZ are then grouped within circular areas or “keyhole” configurations (circles plus radial sectors) that define a total of 41 Evacuation Regions.
- The time-varying external circumstances are represented as Evacuation Scenarios, each described in terms of the following factors: (1) Season (Summer, Winter); (2) Day of Week (Midweek, Weekend); (3) Time of Day (Midday, Evening); and (4) Weather (Good, Rain, Snow). One special event scenario involving the Kinetic Triathlon at Lake Anna State Park was considered. One roadway impact scenario was considered wherein a northbound segment of US-522 NB at CR-612 was closed for the duration of the evacuation.
- Staged evacuation was considered for those regions wherein the 2 mile radius and sectors downwind to 5 miles were evacuated.
- As per NUREG/CR-7002, the Planning Basis for the calculation of ETE is:
  - A rapidly escalating accident at the NAPS that quickly assumes the status of General Emergency such that the Advisory to Evacuate is virtually coincident with the siren alert, and no early protective actions have been implemented.
  - While an unlikely accident scenario, this planning basis will yield ETE, measured as the elapsed time from the Advisory to Evacuate until the stated percentage of the population exits the impacted Region, that represent “upper bound” estimates. This conservative Planning Basis is applicable for all initiating events.
- If the emergency occurs while schools are in session, the ETE study assumes that the children will be evacuated by bus directly to Evacuation Assembly Centers (EAC) located outside the EPZ. Parents, relatives, and neighbors are advised to not pick up their children at school prior to the arrival of the buses dispatched for that purpose. The ETE for schoolchildren are calculated separately.
- Evacuees who do not have access to a private vehicle will either ride-share with relatives, friends or neighbors, or be evacuated by buses provided as specified in each of the counties Radiological Emergency Response Plans (RERP). Those in special facilities will likewise be evacuated with public transit, as needed: bus, van, or ambulance, as required. Separate ETE are calculated for the transit-dependent evacuees, for homebound special needs population, and for those evacuated from special facilities.
- Attended final meeting with Dominion personnel and emergency management personnel representing state and county governments to review results and receive comments.

Computation of ETE

A total of 574 ETE were computed for the evacuation of the general public. Each ETE quantifies the aggregate evacuation time estimated for the population within one of the 41 Evacuation Regions to evacuate from that Region, under the circumstances defined for one of the 14 Evacuation Scenarios (41 x 14 = 574). Separate ETE are calculated for transit-dependent evacuees, including schoolchildren for applicable scenarios.

Except for Region R03, which is the evacuation of the entire EPZ, only a portion of the people within the EPZ would be advised to evacuate. That is, the Advisory to Evacuate applies only to those people occupying the specified impacted region. It is assumed that 100 percent of the people within the impacted region will evacuate in response to this Advisory. The people occupying the remainder of the EPZ outside the impacted region may be advised to take shelter.

The computation of ETE assumes that 20% of the population within the EPZ but outside the impacted region, will elect to "voluntarily" evacuate. In addition, 20% of the population in the Shadow Region will also elect to evacuate. These voluntary evacuees could impede those who are evacuating from within the impacted region. The impedance that could be caused by voluntary evacuees is considered in the computation of ETE for the impacted region.

Staged evacuation is considered wherein those people within the 2-mile region evacuate immediately, while those beyond 2 miles, but within the EPZ, shelter-in-place. Once 90% of the 2-mile region is evacuated, those people beyond 2 miles begin to evacuate. As per federal guidance, 20% of people beyond 2 miles will evacuate (non-compliance) even though they are advised to shelter-in-place.

The computational procedure is outlined as follows:

- A link-node representation of the highway network is coded. Each link represents a unidirectional length of highway; each node usually represents an intersection or merge point. The capacity of each link is estimated based on the field survey observations and on established traffic engineering procedures.
- The evacuation trips are generated at locations called "zonal centroids" located within the EPZ and Shadow Region. The trip generation rates vary over time reflecting the mobilization process, and from one location (centroid) to another depending on population density and on whether a centroid is within, or outside, the impacted area.
- The evacuation model computes the routing patterns for evacuating vehicles that are compliant with federal guidelines (outbound relative to the location of the plant), then simulate the traffic flow movements over space and time. This simulation process estimates the rate that traffic flow exits the impacted region.

The ETE statistics provide the elapsed times for 90 percent and 100 percent, respectively, of the population within the impacted region, to evacuate from within the impacted region. These statistics are presented in tabular and graphical formats. The 90th percentile ETE have been identified as the values that should be considered when making protective action decisions because the 100th percentile ETE are prolonged by those relatively few people who take longer to mobilize. This is referred to as the "evacuation tail" in Section 4.0 of NUREG/CR-7002.

The use of a public outreach (information) program to emphasize the need for evacuees to minimize the time needed to prepare to evacuate (secure the home, assemble needed clothes, medicines, etc.) should also be considered.

Traffic Management

This study references the comprehensive traffic management plans provided by Louisa, Spotsylvania, Orange, Caroline, and Hanover Counties, and identifies critical intersections.

Selected Results

A compilation of selected information is presented on the following pages in the form of Figures and Tables extracted from the body of the report; these are described below.

- Figure 6-1 displays a map of the NAPS EPZ showing the layout of the 25 PAZ that comprise, in aggregate, the EPZ.
- Table 3-1 presents the estimates of permanent resident population in each PAZ based on the 2010 Census data.
- Table 6-1 defines each of the 41 Evacuation Regions in terms of their respective groups of PAZ.
- Table 6-2 lists the Evacuation Scenarios.
- Tables 7-1 and 7-2 are compilations of ETE. These data are the times needed to clear the indicated regions of 90 and 100 percent of the population occupying these regions, respectively. These computed ETE include consideration of mobilization time and of estimated voluntary evacuations from other regions within the EPZ and from the Shadow Region.
- Tables 7-3 and 7-4 present ETE for the 2-mile region for un-staged and staged evacuations for the 90th and 100th percentiles, respectively.
- Table 8-7 presents ETE for the schoolchildren in good weather.
- Table 8-11 presents ETE for the transit-dependent population in good weather.
- Figure H-8 presents an example of an Evacuation Region (Region R08) to be evacuated under the circumstances defined in Table 6-1. Maps of all regions are provided in Appendix H.

Conclusions

- General population ETE were computed for 574 unique cases – a combination of 41 unique Evacuation Regions and 14 unique Evacuation Scenarios. Table 7-1 and Table 7-2 document these ETE for the 90th and 100th percentiles. These ETE range from 1:45 (hr:min) to 3:45 at the 90th percentile.
- Inspection of Table 7-1 and Table 7-2 indicates that the ETE for the 100th percentile are significantly longer than those for the 90th percentile. This is the result of the long trip generation "tail". As these stragglers mobilize, the aggregate rate of egress slows since many vehicles have already left the EPZ. Towards the end of the process, relatively few evacuation routes service the remaining demand. See Figures 7-7 through 7-20.

- Inspection of Table 7-3 and Table 7-4 indicates that a staged evacuation provides no benefits to evacuees from within the 2 mile region and unnecessarily delays the evacuation of those beyond 2 miles (compare Regions R02 and R04 through R15 with Regions R29 through R41, respectively, in Tables 7-1 and 7-2). See Section 7.6 for additional discussion.
- Comparison of Scenarios 9 (winter, weekend, midday) and 13 (winter, weekend, midday, special event) in Table 7-1 indicates that the special event does not materially affect the ETE. See Section 7.5 for additional discussion.
- Comparison of Scenarios 1 and 14 in Table 7-1 indicates that the roadway closure – a northbound section of US-522 NB at CR-612 – does not have a significant impact on the 90th or 100th percentile ETE. Sufficient reserve capacity exists on CR-612 to service the additional evacuating traffic demand. See Section 7.5 for additional discussion.
- There is minimal traffic congestion within the EPZ. All congestion within the EPZ clears by 2 hours and 10 minutes after the Advisory to Evacuate (earlier for winter cases). See Section 7.3 and Figures 7-3 through 7-6.
- Separate ETE were computed for schools, the one medical facility, transit-dependent persons and homebound special needs persons. The average single-wave ETE for these facilities are within a similar range as the general population ETE at the 90th percentile. See Section 8.
- Table 8-5 indicates that there are enough buses and wheelchair vans available to evacuate the entire transit-dependent population within the EPZ in a single wave, if transportation resources are shared by the counties. However, if for any reason transportation resources could not be shared, then Spotsylvania County would require a second wave for two of their schools in order to evacuate all schoolchildren. The second-wave ETE for schools do exceed the general population ETE at the 90th percentile. Mutual aid agreements with neighboring counties and assistance from the state could be used to address the shortfall in bus resources (See Section 8.4).
- The general population ETE at the 90th percentile is insensitive to reductions in the base trip generation time of 5½ hours. The general population ETE at the 100th percentile, however, closely mirrors trip generation time. See Table M-1.
- The general population ETE is insensitive to the voluntary evacuation of vehicles in the Shadow Region. Tripling the shadow evacuation percentage results in no change in the 90th percentile ETE. See Table M-2.
- An increase in permanent resident population of 150% or more, or a decrease in population of 85% or more results in ETE changes which meet the criteria for updating ETE between decennial Censuses. See Section M.3.
- The additional employees present during an outage concurrent with construction of the New Unit 3, does not affect the ETE, with the exception of the 90th percentile ETE for the 2-mile region, which decreased by 5 minutes. See Section M.4.

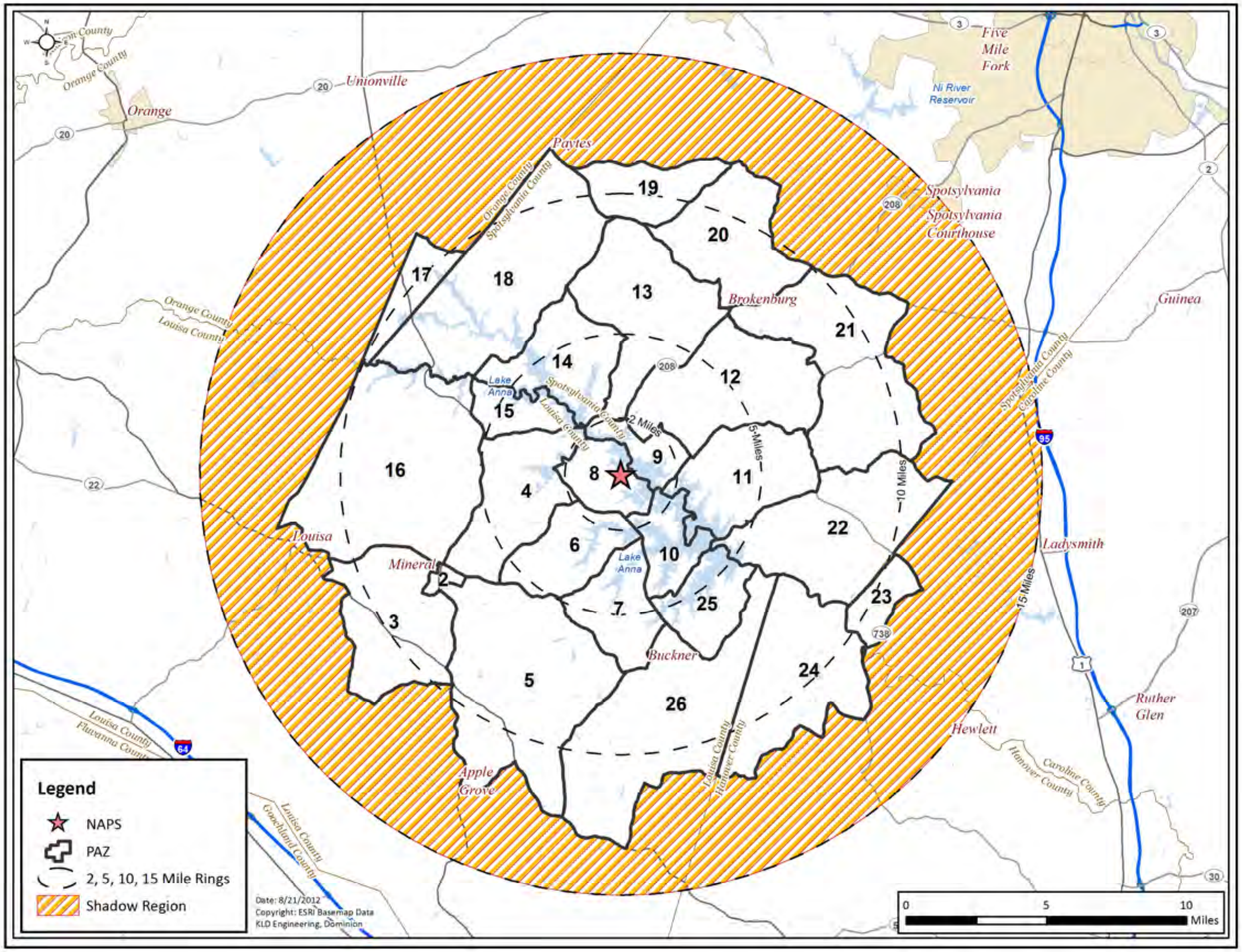


Figure 6-1. NAPS EPZ PAZ

Table 3-1. EPZ Permanent Resident Population

PAZ	2000 Population	2008 Population (Estimated)[1]	2010 Population
2	418	645	466
3	1,241	1,843	1,490
4	837	1,842	1,107
5	1,331	1,740	1,472
6	308	727	484
7	318	939	484
8	287	885	409
9	117	426	203
10	245	1,151	429
11	740	1,345	981
12	1,222	1,467	1,561
13	991	1,312	1,364
14	541	1,719	803
15	451	1,589	697
16	1,138	2,153	1,601
17	50	223	144
18	1,664	3,624	2,416
19	246	352	383
20	894	1,025	1,026
21	1,901	2,125	2,232
22	1,355	1,639	1,538
23	263	341	260
24	716	989	946
25	312	902	464
26	1,729	2,420	2,242
TOTAL	**19,315**	**33,423**	**25,202**
EPZ Population Growth:		**2000-2010**	**30.48%**
EPZ Population Difference:		**2008-2010**	**-24.60%**

Notes: 1 - 2008 COLA ETE – Resident address points within each county (except Caroline County) were provided by VDEM. Average household size from telephone survey (2.57) was used to determine 2008 EPZ population. 2000 Census projected to 2008 using county growth rate was used for Caroline County.

Table 6-1. Description of Evacuation Regions

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																							
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R01	2-Mile Radius	2- Mile Radius					x		x	x	x																
R02	5-Mile Radius	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R03	Full EPZ	Full EPZ	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Evacuate 2-Mile Radius and Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																							
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R04	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R05	NE	34° - 56°					x		x	x	x	x	x	x													
R06	ENE, E	57° - 101°					x		x	x	x	x	x														
R07	ESE	102° - 123°					x		x	x	x	x														x	
R08	SE	124° - 146°					x	x	x	x	x	x														x	
R09	SSE, S	147° - 191°					x	x	x	x	x															x	
R10	SSW	192° - 213°					x	x	x	x	x																
R11	SW	214° - 236°			x		x	x	x	x	x																
R12	WSW	237° - 258°			x		x		x	x	x																
R13	W	259°- 281°			x		x		x	x	x					x											
R14	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R15	NNW	327° - 349°					x		x	x	x			x	x	x											
Evacuate 5-Mile Radius and Downwind to the EPZ Boundary																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																							
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R16	N	349° - 11°			x		x	x	x	x	x	x	x	x	x	x			x	x	x					x	
R17	NNE	12° - 33°			x		x	x	x	x	x	x	x	x	x	x			x	x	x	x				x	
R18	NE	34° - 56°			x		x	x	x	x	x	x	x	x	x	x				x	x	x				x	
R19	ENE	57° - 78°			x		x	x	x	x	x	x	x	x	x	x					x	x	x			x	
R20	E	79° - 101°			x		x	x	x	x	x	x	x	x	x	x						x	x	x		x	
R21	ESE	102° - 123°			x		x	x	x	x	x	x	x	x	x	x						x	x	x	x	x	x
R22	SE	124° - 146°			x		x	x	x	x	x	x	x	x	x	x							x	x	x	x	x
R23	SSE, S	147° - 191°			x	x	x	x	x	x	x	x	x	x	x	x									x	x	x
R24	SSW	192° - 213°		x	x	x	x	x	x	x	x	x	x	x	x	x										x	x

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R25	SW, WSW	214° - 258°	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x									x	
R26	W	259° - 281°	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R27	WNW, NW	282° - 326°			x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R28	NNW	327° - 349°			x		x	x	x	x	x	x	x	x	x	x		x	x	x						x	

Staged Evacuation - 2-Mile Radius Evacuates, then Evacuate Downwind to 5 Miles

Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R29	-	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R30	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R31	NE	34° - 56°					x		x	x	x	x	x	x													
R32	ENE, E	57° - 101°					x		x	x	x	x	x														
R33	ESE	102° - 123°					x		x	x	x	x														x	
R34	SE	124° - 146°					x	x	x	x	x	x														x	
R35	SSE, S	147° - 191°					x	x	x	x	x															x	
R36	SSW	192° - 213°					x	x	x	x	x																
R37	SW	214° - 236°			x		x	x	x	x	x																
R38	WSW	237° - 258°			x		x		x	x	x																
R39	W	259°- 281°			x		x		x	x	x					x											
R40	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R41	NNW	327° - 349°					x		x	x	x			x	x	x											

Shelter-in-Place until 90% ETE for R01, then Evacuate | PAZ Shelter-in-Place | PAZ Evacuate

Table 6-2. Evacuation Scenario Definitions

Scenario	Season[1]	Day of Week	Time of Day	Weather	Special
1	Summer	Midweek	Midday	Good	None
2	Summer	Midweek	Midday	Rain	None
3	Summer	Weekend	Midday	Good	None
4	Summer	Weekend	Midday	Rain	None
5	Summer	Midweek, Weekend	Evening	Good	None
6	Winter	Midweek	Midday	Good	None
7	Winter	Midweek	Midday	Rain	None
8	Winter	Midweek	Midday	Snow	None
9	Winter	Weekend	Midday	Good	None
10	Winter	Weekend	Midday	Rain	None
11	Winter	Weekend	Midday	Snow	None
12	Winter	Midweek, Weekend	Evening	Good	None
13	Winter	Weekend	Midday	Good	Kinetic Triathlon at Lake Anna State park
14	Summer	Midweek	Midday	Good	Roadway Impact – One Segment of US-522 NB will be Closed

[1] Winter means that school is in session (also applies to spring and autumn). Summer means that school is not in session.

Table 7-1. Time to Clear the Indicated Area of *90* Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:30
R02	2:25	2:25	1:50	1:50	1:50	2:30	2:35	3:25	1:50	1:50	2:55	1:55	1:50	2:30
R03	2:35	2:35	2:00	2:00	2:00	2:40	2:40	3:30	2:00	2:00	3:05	2:00	2:00	2:35
2-Mile Region and Keyhole to 5 Miles														
R04	2:20	2:20	1:45	1:45	1:45	2:30	2:30	3:15	1:50	1:50	2:55	1:50	1:50	2:20
R05	2:25	2:25	1:50	1:50	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R07	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:25
R08	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:15	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R10	2:15	2:15	1:50	1:50	1:50	2:20	2:20	3:05	1:50	1:50	2:50	1:50	1:50	2:20
R11	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:15	2:20	1:50	1:50	1:50	2:20	2:25	3:10	1:50	1:50	2:50	1:50	1:50	2:20
R13	2:20	2:20	1:45	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R14	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
R15	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
5-Mile Region and Keyhole to EPZ Boundary														
R16	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R17	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R18	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R19	2:30	2:35	1:55	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R20	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R21	2:35	2:35	2:00	2:05	2:05	2:40	2:40	3:30	2:00	2:00	3:00	2:00	2:00	2:35
R22	2:30	2:35	2:00	2:00	2:05	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R23	2:30	2:30	2:00	2:00	2:00	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R24	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R25	2:30	2:30	1:55	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R26	2:30	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R27	2:25	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
R28	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:10	2:15	3:30	2:10	2:10	2:55
R30	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R31	2:55	2:55	2:15	2:15	2:15	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R32	2:50	2:50	2:10	2:10	2:10	2:50	2:55	3:40	2:10	2:10	3:25	2:10	2:10	2:50
R33	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:25	2:05	2:05	2:50
R34	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R35	2:45	2:45	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:10	3:25	2:05	2:05	2:50
R36	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:30	2:05	2:05	3:20	2:05	2:05	2:45
R37	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R38	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:35	2:05	2:05	3:20	2:05	2:05	2:45
R39	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R40	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R41	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:05	3:25	2:05	2:05	2:50

Table 7-2. Time to Clear the Indicated Area of *100* Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R03	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
2-Mile Region and Keyhole to 5 Miles														
R04	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R05	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R06	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R07	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R08	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R09	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R10	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R11	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R12	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R13	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R14	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R15	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
5-Mile Region and Keyhole to EPZ Boundary														
R16	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R17	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R18	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R19	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R20	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R21	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R22	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R23	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R24	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R25	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R26	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R27	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R28	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R30	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R31	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R32	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R33	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R34	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R35	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R36	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R37	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R38	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R39	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R40	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R41	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35

Table 7-3. Time to Clear 90 Percent of the 2-Mile Region

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R02	2:25	2:25	1:45	1:50	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R05	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R07	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R08	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R10	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R11	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R13	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R14	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R15	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45
R30	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R31	2:40	2:40	1:55	1:55	1:55	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R32	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R33	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R34	2:40	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R35	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R36	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R37	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	**Midday**		**Midday**		**Evening**	**Midday**			**Midday**			**Evening**	**Evening**	**Midday**
	Good Weather	**Rain**	**Good Weather**	**Rain**	**Good Weather**	**Good Weather**	**Rain**	**Snow**	**Good Weather**	**Rain**	**Snow**	**Good Weather**	**Special Event**	**Roadway Impact**
R38	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R39	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R40	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R41	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40

Table 7-4. Time to Clear 100 Percent of the 2-Mile Region

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
Region	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R05	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R06	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R07	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R08	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R09	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R10	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R11	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R12	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R13	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R14	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R15	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R30	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R31	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R32	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R33	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R34	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R35	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R36	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R37	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R38	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R39	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R40	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R41	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

Table 8-7. School Evacuation Time Estimates – Good Weather

School	Driver Mobilization Time (min)	Loading Time (min)	Dist. To EPZ Bdry (mi)	Average Speed (mph)	Travel Time to EPZ Bdry (min)	ETE (hr:min)	Dist. EPZ Bdry to EAC (mi.)	Travel Time from EPZ Bdry to EAC (min)	ETE to EAC (hr:min)
LOUISA COUNTY SCHOOLS									
Louisa County High School	90	15	3.7	45.0	5	**1:50**	8.3	11	**2:05**
Louisa County Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Mineral Christian Preschool	90	15	4.8	45.0	7	**1:55**	8.3	11	**2:10**
Thomas Jefferson Elementary School	90	15	1.5	45.0	3	**1:50**	8.6	11	**2:05**
SPOTSYLVANIA COUNTY SCHOOLS									
Berkeley Elementary School	90	15	2.1	44.7	3	**1:50**	8.0	11	**2:05**
Livingston Elementary School	90	15	9.1	45.0	13	**2:00**	8.3	11	**2:10**
Post Oak Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Spotsylvania High School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
Spotsylvania High School - Governor's School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
					Maximum for EPZ:	**2:00**		**Maximum:**	**2:10**
					Average for EPZ:	**1:55**		**Average:**	**2:10**

Table 8-11. Transit-Dependent Evacuation Time Estimates – Good Weather

Route Number	Bus Number	One-Wave Mobilization (min)	Route Length (miles)	Speed (mph)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)	Distance to EAC (miles)	Two-Wave Travel Time to EAC (min)	Unload (min)	Driver Rest (min)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)
1	1	105	12.6	45.0	17	30	**2:35**	8.2	11	5	10	41	30	**4:15**
2	1	105	17.4	38.9	27	30	**2:45**	8.2	11	5	10	50	30	**4:35**
3	1	105	20.2	44.6	27	30	**2:45**	8.2	11	5	10	51	30	**4:35**
4	1	105	15.3	45.0	20	30	**2:35**	8.2	11	5	10	45	30	**4:20**
5	1	105	13.0	45.0	17	30	**2:35**	8.9	12	5	10	43	30	**4:15**
6	1	105	25.5	45.0	34	30	**2:50**	8.5	11	5	10	59	30	**4:50**
7	1	105	19.8	45.0	26	30	**2:45**	12.1	16	5	10	56	30	**4:45**
8	1	105	32.2	45.0	43	30	**3:00**	8.2	11	5	10	67	30	**5:05**
9	1	105	22.8	45.0	30	30	**2:45**	8.2	11	5	10	55	30	**4:40**
10	1	105	26.3	40.2	39	30	**2:55**	8.2	11	5	10	61	30	**4:55**
11	1	105	17.3	45.0	23	30	**2:40**	9.5	13	5	10	49	30	**4:30**
12	1	105	27.6	45.0	37	30	**2:55**	8.3	11	5	10	61	30	**4:55**
13	1	105	17.0	44.8	23	30	**2:40**	8.3	11	5	10	47	30	**4:25**
14	1	105	36.6	45.0	49	30	**3:05**	13.5	18	5	10	80	30	**5:30**
15	1	105	17.5	45.0	23	30	**2:40**	8.3	11	5	10	48	30	**4:25**
16	1	105	23.2	44.5	31	30	**2:50**	7.8	10	5	10	55	30	**4:45**
17	1	105	9.5	43.0	13	30	**2:30**	7.8	10	5	10	36	30	**4:05**
18	1	105	30.5	45.0	41	30	**3:00**	13.5	18	5	10	72	30	**5:15**
19	1	105	18.5	45.0	25	30	**2:40**	13.5	18	5	10	56	30	**4:40**
20	1	105	29.2	45.0	39	30	**2:55**	13.5	18	5	10	70	30	**5:10**
21	1	105	10.7	45.0	14	30	**2:30**	14.8	20	5	10	47	30	**4:25**
22	1	105	5.1	45.0	7	30	**2:25**	12.6	17	5	10	31	30	**4:00**
23	1	105	7.7	45.0	10	30	**2:25**	13.4	18	5	10	38	30	**4:10**
24	1	105	8.0	35.5	13	30	**2:30**	13.4	18	5	10	41	30	**4:15**
25	1	105	7.2	45.0	10	30	**2:25**	12.7	17	5	10	36	30	**4:05**
						Maximum ETE:	**3:05**						**Maximum ETE:**	**5:30**
						Average ETE:	**2:45**						**Average ETE:**	**4:35**

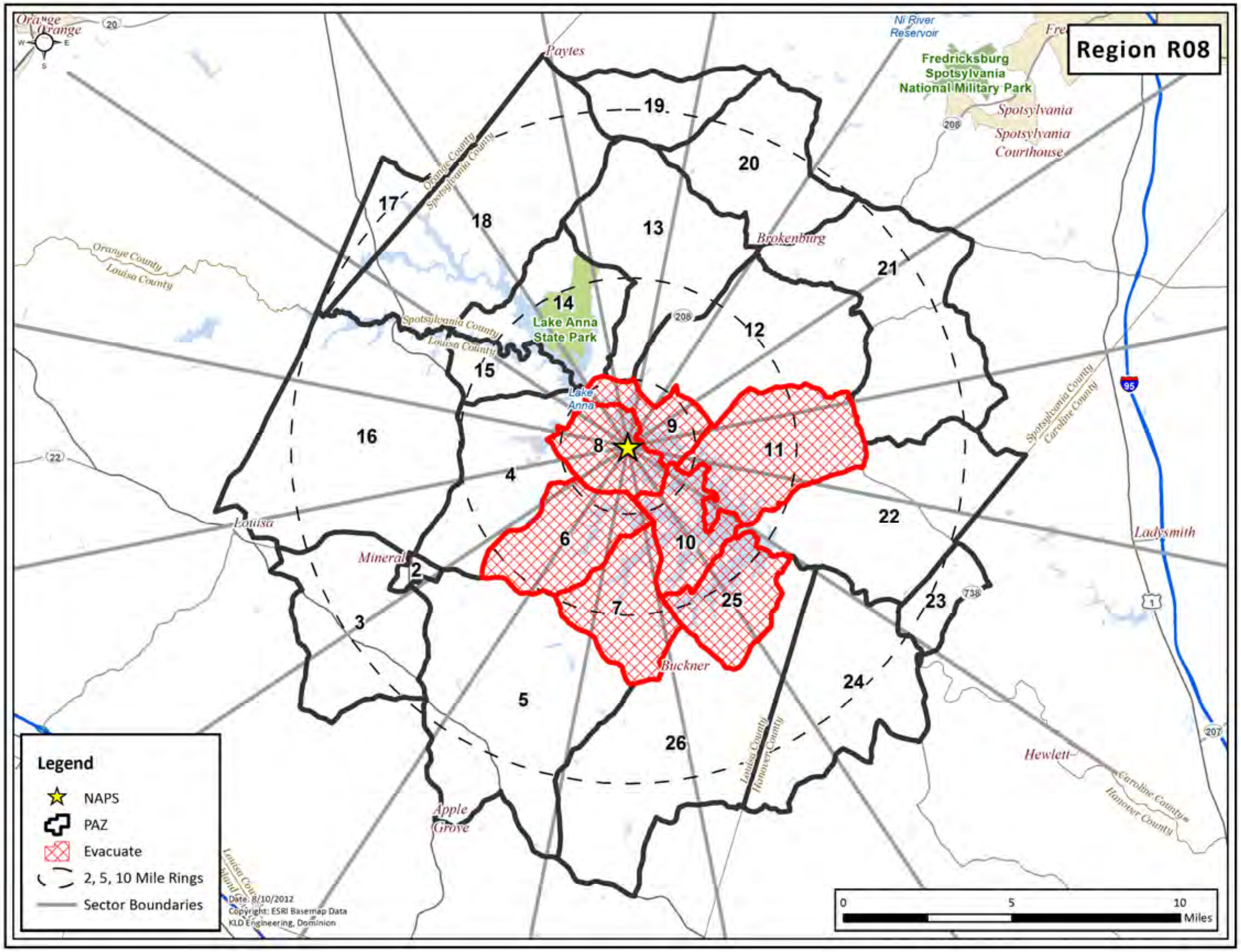


Figure H-8. Region R08

1 INTRODUCTION

This report describes the analyses undertaken and the results obtained by a study to develop Evacuation Time Estimates (ETE) for the North Anna Power Station (NAPS), located in Louisa County, Virginia. ETE provide State and local governments with site-specific information needed for Protective Action decision-making.

In the performance of this effort, guidance is provided by documents published by Federal Governmental agencies. Most important of these are:

- Criteria for Development of Evacuation Time Estimate Studies, NUREG/CR-7002, November 2011.
- Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, NUREG 0654/FEMA REP 1, Rev. 1, November 1980.
- Analysis of Techniques for Estimating Evacuation Times for Emergency Planning Zones, NUREG/CR 1745, November 1980.
- Development of Evacuation Time Estimates for Nuclear Power Plants, NUREG/CR-6863, January 2005.

The work effort reported herein was supported and guided by local stakeholders who contributed suggestions, critiques, and the local knowledge base required. Table 1-1 presents a summary of stakeholders and interactions.

Table 1-1. Stakeholder Interaction

Stakeholder	Nature of Stakeholder Interaction
Dominion	Meetings to define data requirements and set up contacts with local government agencies. Obtain NAPS emergency plan. Final meeting to discuss results.
Louisa County Emergency Management / Fire & EMS	Meetings to define data requirements. Obtain special facility data. Final meeting to discuss results.
Spotsylvania County Emergency Management / Fire & EMS	
Caroline County Emergency Management / Fire & EMS	
Orange County Emergency Management / Fire & EMS	
Hanover County Emergency Management / Fire & EMS	
Virginia Department of Emergency Management	Meetings to define data requirements and set up contacts with local government agencies. Obtain county emergency plans, population data, GIS data and special facility data. Final meeting to discuss results.

1.1 Overview of the ETE Process

The following outline presents a brief description of the work effort in chronological sequence:

1. Information Gathering:
    a. Defined the scope of work in discussions with representatives from Dominion.
    b. Attended meetings with emergency planners from Louisa County EMA, Spotsylvania County EMA, Orange County EMA, Caroline County EMA and Hanover County EMA to identify issues to be addressed and resources available.
    c. Conducted a detailed field survey of the highway system and of area traffic conditions within the Emergency Planning Zone (EPZ) and Shadow Region.
    d. Obtained demographic data from the 2010 census and Virginia Department of Emergency Management.
    e. Re-analyzed results of the 2007 telephone survey and supplemented existing data with results from the Surry Power Station (SPS) telephone survey.
    f. Conducted a data collection effort to identify and describe schools, special facilities, major employers, transportation providers, and other important information.
2. Estimated distributions of Trip Generation times representing the time required by various population groups (permanent residents, employees, and transients) to prepare (mobilize) for the evacuation trip. These estimates are primarily based upon the random sample telephone survey.
3. Defined Evacuation Scenarios. These scenarios reflect the variation in demand, in trip generation distribution and in highway capacities, associated with different seasons, day of week, time of day and weather conditions.
4. Reviewed the existing traffic management plan to be implemented by local and state police in the event of an incident at the plant. Traffic control is applied at specified Traffic Control Points (TCP) located within the EPZ.
5. Used existing PAZ to define evacuation regions. The EPZ is partitioned into 25 PAZ along jurisdictional and geographic boundaries. "Regions" are groups of contiguous PAZ for which ETE are calculated. The configurations of these Regions reflect wind direction and the radial extent of the impacted area. Each Region, other than those that approximate circular areas, approximates a "key-hole section" within the EPZ as recommended by NUREG/CR-7002.
6. Estimated demand for transit services for persons at "Special Facilities" and for transit-dependent persons at home.
7. Prepared the input streams for the DYNEV II system.
    a. Estimated the evacuation traffic demand, based on the available information

derived from Census data, and from data provided by local and state agencies, Dominion and from the telephone survey.

b. Applied the procedures specified in the 2010 Highway Capacity Manual (HCM[1]) to the data acquired during the field survey, to estimate the capacity of all highway segments comprising the evacuation routes.

c. Developed the link-node representation of the evacuation network, which is used as the basis for the computer analysis that calculates the ETE.

d. Calculated the evacuating traffic demand for each Region and for each Scenario.

e. Specified selected candidate destinations for each "origin" (location of each "source" where evacuation trips are generated over the mobilization time) to support evacuation travel consistent with outbound movement relative to the location of the NAPS.

8. Executed the DYNEV II model to determine optimal evacuation routing and compute ETE for all residents, transients and employees ("general population") with access to private vehicles. Generated a complete set of ETE for all specified Regions and Scenarios.

9. Documented ETE in formats in accordance with NUREG/CR-7002.

10. Calculated the ETE for all transit activities including those for special facilities (schools, medical facilities, etc.), for the transit-dependent population and for homebound special needs population.

1.2 The North Anna Power Station Location

The North Anna Power Station is located approximately 40 miles northwest of Richmond, Virginia. The Emergency Planning Zone (EPZ) consists of parts of Louisa, Spotsylvania, Orange, Caroline and Hanover Counties in Virginia. Figure 1-1 displays the area surrounding the NAPS. This map identifies the communities in the area and the major roads.

[1] Highway Capacity Manual (HCM 2010), Transportation Research Board, National Research Council, 2010.

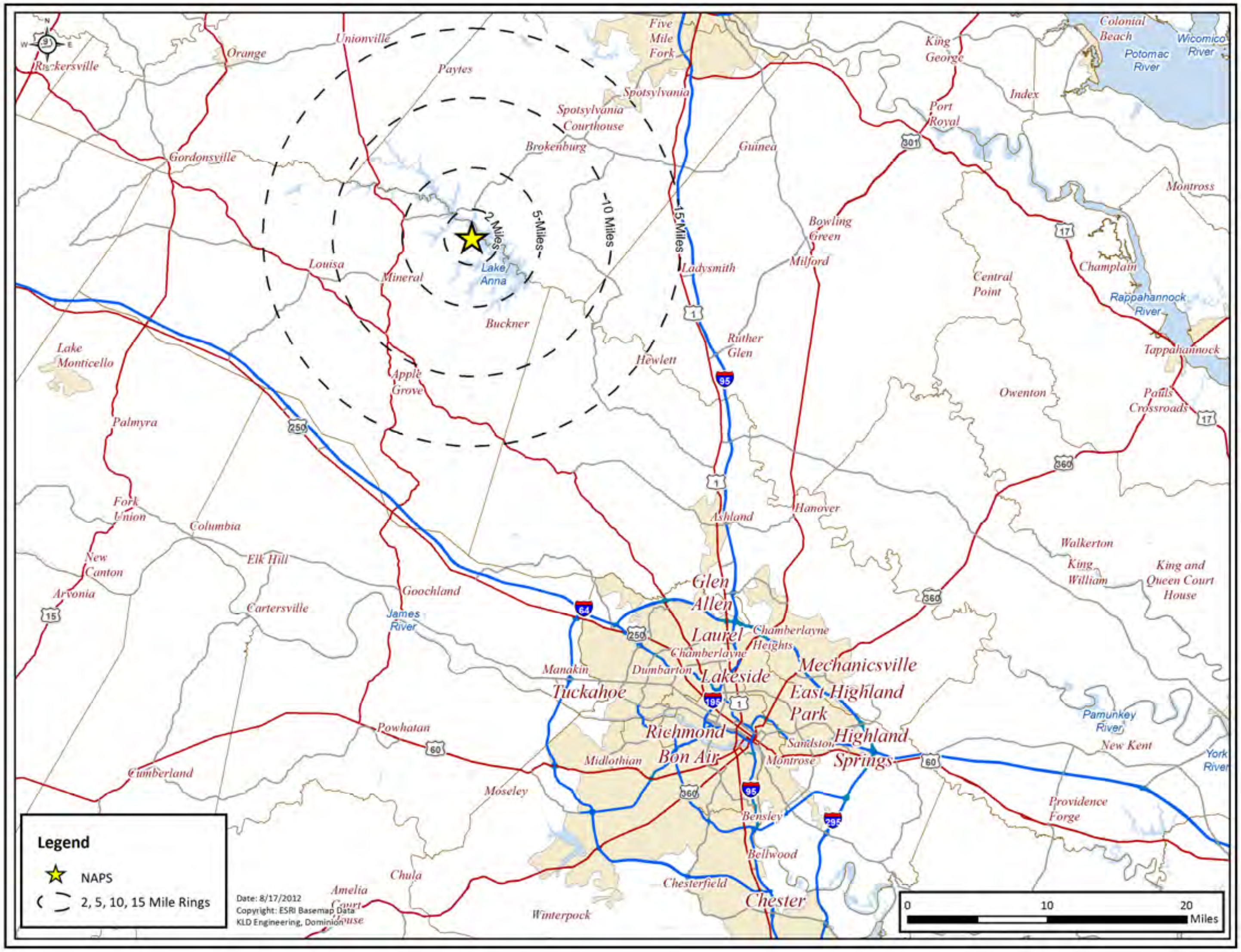


Figure 1-1. North Anna Power Station Location

1.3 Preliminary Activities

These activities are described below.

Field Surveys of the Highway Network

KLD personnel drove the entire highway system within the EPZ and the Shadow Region which consists of the area between the EPZ boundary and approximately 15 miles radially from the plant. The characteristics of each section of highway were recorded. These characteristics are shown in Table 1-2:

Table 1-2. Highway Characteristics

- Number of lanes
- Lane width
- Shoulder type & width
- Interchange geometries
- Lane channelization & queuing capacity (including turn bays/lanes)
- Geometrics: curves, grades (>4%)
- Posted speed
- Actual free speed
- Abutting land use
- Control devices
- Intersection configuration (including roundabouts where applicable)
- Traffic signal type
- Unusual characteristics: Narrow bridges, sharp curves, poor pavement, flood warning signs, inadequate delineations, toll booths, etc.

Video and audio recording equipment were used to capture a permanent record of the highway infrastructure. No attempt was made to meticulously measure such attributes as lane width and shoulder width; estimates of these measures based on visual observation and recorded images were considered appropriate for the purpose of estimating the capacity of highway sections. For example, Exhibit 15-7 in the HCM indicates that a reduction in lane width from 12 feet (the "base" value) to 10 feet can reduce free flow speed (FFS) by 1.1 mph – not a material difference – for two-lane highways. Exhibit 15-30 in the HCM shows little sensitivity for the estimates of Service Volumes at Level of Service (LOS) E (near capacity), with respect to FFS, for two-lane highways.

The data from the audio and video recordings were used to create detailed geographical information systems (GIS) shapefiles and databases of the roadway characteristics and of the traffic control devices observed during the road survey; this information was referenced while preparing the input stream for the DYNEV II System.

As documented on page 15-5 of the HCM 2010, the capacity of a two-lane highway is 1700 passenger cars per hour in one direction. For freeway sections, a value of 2250 vehicles per hour per lane is assigned, as per Exhibit 11-17 of the HCM 2010. The road survey has identified several segments which are characterized by adverse geometrics on two-lane highways which are reflected in reduced values for both capacity and speed. These estimates are consistent with the service volumes for LOS E presented in HCM Exhibit 15-30. These links may be identified by reviewing Appendix K. Link capacity is an input to DYNEV II which computes the ETE. Further discussion of roadway capacity is provided in Section 4 of this report.

Traffic signals are either pre-timed (signal timings are fixed over time and do not change with the traffic volume on competing approaches), or are actuated (signal timings vary over time based on the changing traffic volumes on competing approaches). Actuated signals require detectors to provide the traffic data used by the signal controller to adjust the signal timings. These detectors are typically magnetic loops in the roadway, or video cameras mounted on the signal masts and pointed toward the intersection approaches. If detectors were observed on the approaches to a signalized intersection during the road survey, detailed signal timings were not collected as the timings vary with traffic volume. TCPs at locations which have control devices are represented as actuated signals in the DYNEV II system.

If no detectors were observed, the signal control at the intersection was considered pre-timed, and detailed signal timings were gathered for several signal cycles. These signal timings were input to the DYNEV II system used to compute ETE, as per NUREG/CR-7002 guidance.

Figure 1-2 presents the link-node analysis network that was constructed to model the evacuation roadway network in the EPZ and Shadow Region. The directional arrows on the links and the node numbers have been removed from Figure 1-2 to clarify the figure. The detailed figures provided in Appendix K depict the analysis network with directional arrows shown and node numbers provided. The observations made during the field survey were used to calibrate the analysis network.

<u>Telephone Survey</u>

A telephone survey was undertaken to gather information needed for the evacuation study. Appendix F presents the survey instrument, the procedures used and tabulations of data compiled from the survey returns.

These data were utilized to develop estimates of vehicle occupancy to estimate the number of evacuating vehicles during an evacuation and to estimate elements of the mobilization process. This database was also referenced to estimate the number of transit-dependent residents.

<u>Computing the Evacuation Time Estimates</u>

The overall study procedure is outlined in Appendix D. Demographic data were obtained from several sources, as detailed later in this report. These data were analyzed and converted into vehicle demand data. The vehicle demand was loaded onto appropriate “source” links of the analysis network using GIS mapping software. The DYNEV II system was then used to compute ETE for all Regions and Scenarios.

<u>Analytical Tools</u>

The DYNEV II System that was employed for this study is comprised of several integrated computer models. One of these is the DYNEV (<u>DY</u>namic <u>N</u>etwork <u>EV</u>acuation) macroscopic simulation model, a new version of the IDYNEV model that was developed by KLD under contract with the Federal Emergency Management Agency (FEMA).

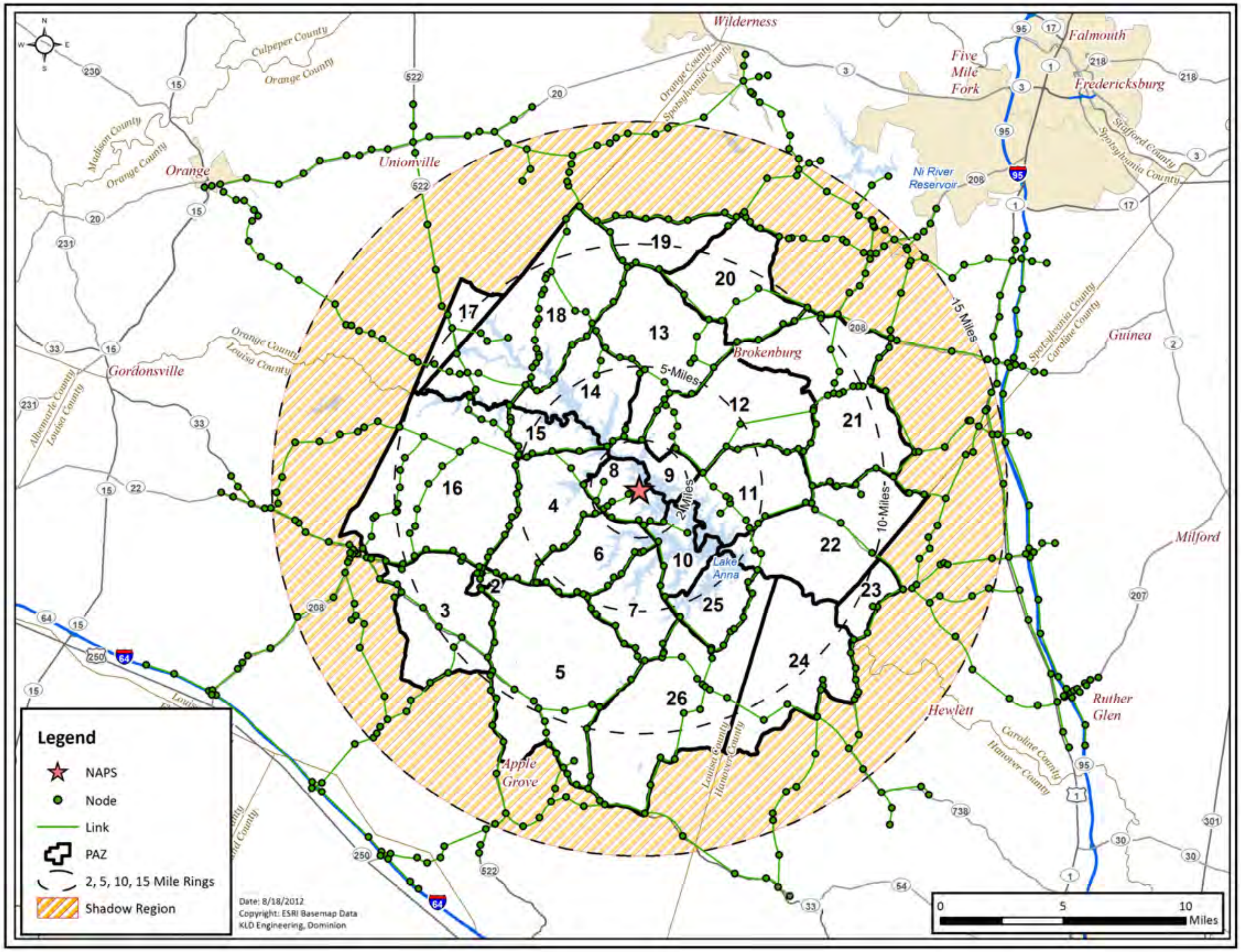


Figure 1-2. NAPS Link-Node Analysis Network

DYNEV II consists of four sub-models:

- A macroscopic traffic simulation model (for details, see Appendix C).
- A Trip Distribution (TD), model that assigns a set of candidate destination (D) nodes for each "origin" (O) located within the analysis network, where evacuation trips are "generated" over time. This establishes a set of O-D tables.
- A Dynamic Traffic Assignment (DTA), model which assigns trips to paths of travel (routes) which satisfy the O-D tables, over time. The TD and DTA models are integrated to form the DTRAD (Dynamic Traffic Assignment and Distribution) model, as described in Appendix B.
- A Myopic Traffic Diversion model which diverts traffic to avoid intense, local congestion, if possible.

Another software product developed by KLD, named UNITES (UNIfied Transportation Engineering System) was used to expedite data entry and to automate the production of output tables.

The dynamics of traffic flow over the network are graphically animated using the software product, EVAN (EVacuation ANimator), developed by KLD. EVAN is GIS based, and displays statistics such as LOS, vehicles discharged, average speed, and percent of vehicles evacuated, output by the DYNEV II System. The use of a GIS framework enables the user to zoom in on areas of congestion and query road name, town name and other geographical information.

The procedure for applying the DYNEV II System within the framework of developing ETE is outlined in Appendix D. Appendix A is a glossary of terms.

For the reader interested in an evaluation of the original model, I-DYNEV, the following references are suggested:

- NUREG/CR-4873 – Benchmark Study of the I-DYNEV Evacuation Time Estimate Computer Code
- NUREG/CR-4874 – The Sensitivity of Evacuation Time Estimates to Changes in Input Parameters for the I-DYNEV Computer Code

The evacuation analysis procedures are based upon the need to:

- Route traffic along paths of travel that will expedite their travel from their respective points of origin to points outside the EPZ.
- Restrict movement toward the plant to the extent practicable, and disperse traffic demand so as to avoid focusing demand on a limited number of highways.
- Move traffic in directions that are generally outbound, relative to the location of the NAPS.

DYNEV II provides a detailed description of traffic operations on the evacuation network. This description enables the analyst to identify bottlenecks and to develop countermeasures that are designed to represent the behavioral responses of evacuees. The effects of these countermeasures may then be tested with the model.

1.4 Comparison with Prior ETE Study

Table 1-3 presents a comparison of the present ETE study with the 2008 study (Revision 1 of the 2007 COLA). The major factors contributing to the differences between the ETE values obtained in this study and those of the previous study can be summarized as follows:

- A decrease in permanent resident population (-24.6% between 2008 estimated population with 2010 Census).
- A decrease in the estimated number of transients in the EPZ.
- An increase in the level of detail of the link-node representation of the roadway network.
- Advances in the model have led to improvement in the ability to model the County TCP.

Table 1-3. ETE Study Comparisons

Topic	Previous ETE Study	Current ETE Study
Resident Population Basis	ArcGIS Software using county specific address shapefiles. 71.4% population growth between 2000 Census and estimated 2008 population. Population = 33,423	ArcGIS Software using 2010 US Census blocks; area ratio method used. Population = 25,202
Resident Population Vehicle Occupancy	2.57 persons/household, 1.42 evacuating vehicles/household yielding: 1.81 persons/vehicle	2.57 persons/household, 1.42 evacuating vehicles/household yielding: 1.81 persons/vehicle.
Employee Population	Employees treated as separate population group. Employee estimates based on information provided about major employers in EPZ. 1.03employees/vehicle based on phone survey results.	Employee estimates based on information provided and phone call made to major employers in the EPZ. 1.04[2] employees per vehicle based on telephone survey results. Employees = 788
Transit-Dependent Population	Estimates based upon U.S. Census data and the results of the telephone survey. A total of 478 people who do not have access to a vehicle, requiring 16 buses to evacuate.	Estimates based upon U.S. Census data and the results of the telephone survey. A total of 360 people who do not have access to a vehicle, requiring 12 buses to evacuate. An additional 191 homebound special needs persons needed special transportation to evacuate (171 required a bus, 20 required a wheelchair-accessible vehicle).

[2] Current study added park and ride commuters into the calculation for employee vehicle occupancy.

Topic	Previous ETE Study	Current ETE Study
Transient Population	Transient estimates based on data provided by the counties within the EPZ and through phone calls to the facilities. Transients = 10,438	Transient estimates based upon phone calls made to facilities, supplemented by observations of the facilities during the road survey and from aerial photography. Transients = 5,273 at recreational facilities and hotels + 1,724 seasonal residents = 6,997 total.
Special Facilities Population	No special facilities within the EPZ	Special facility population based upon phone call made to the one facility. Current census = 23 Buses Required = 1 Wheelchair Van Required = 1
School Population	School population based on data provided by the counties within the EPZ. School enrollment = 6,859 Vehicles originating at schools = 127	School population based on data provided by the counties within the EPZ, supplemented with 2011-2012 enrollment data from a Virginia State website. School enrollment = 6,427 Buses required = 113
Voluntary evacuation from within EPZ in areas outside region to be evacuated	50 percent of population within the outer portion of the region; 35 percent, in annular ring between the outer portion and the EPZ boundary (See Figure 2-1).	20 percent of the population within the EPZ, but not within the Evacuation Region (see Figure 2-1)
Shadow Evacuation	30% of people outside of the EPZ, within the shadow area (See Figure 7-2).	20% of people outside of the EPZ within the Shadow Region (See Figure 7-2).
Network Size	635 Links; 487 Nodes (See Figure 1-2).	856 links; 665 nodes (See Figure 1-2).
Roadway Geometric Data	Field surveys conducted in 2007. Major intersections were video archived. GIS shape-files of signal locations and roadway characteristics created during road survey. Road capacities based on 2000 HCM.	Field surveys conducted in February 2012. Roads and intersections were video archived. Road capacities based on 2010 HCM.
School Evacuation	Direct evacuation to designated Evacuation Assembly Center.	Direct evacuation to designated Evacuation Assembly Center.
Ridesharing	Assumed 50 percent of transit dependent persons will evacuate with a neighbor or friend.	Assumed 50 percent of transit dependent persons will evacuate with a neighbor or friend.

Topic	Previous ETE Study	Current ETE Study
Trip Generation for Evacuation	Trip generation curves based on residential telephone survey of specific pre-trip mobilization activities: Residents with commuters returning leave between 30 minutes and 5 hours; for snow scenarios this increases to between 30 minutes and 6 hours. Residents without commuters returning leave between 15 minutes and 4 hours; for snow scenarios this increases to between 15 minutes and 5 hours. Employees and transients leave between 15 minutes and 3 hours. All times measured from the Advisory to Evacuate.	Trip generation curves based on based on residential telephone survey of specific pre-trip mobilization activities: Residents with commuters returning leave between 30 and 330 minutes. Residents without commuters returning leave between 10 and 270 minutes. Employees and transients leave between 10 and 150 minutes. All times measured from the Advisory to Evacuate.
Weather	Normal, Rain, or Snow. The capacity and free flow speed of all links in the network are reduced by 10% in the event of rain and 20% for snow.	Normal, Rain, or Snow. The capacity and free flow speed of all links in the network are reduced by 10% in the event of rain and 20% for snow.
Modeling	IDYNEV System: TRAD and PCDYNEV.	DYNEV II System – Version 4.0.8.0
Special Events	Two considered – Construction of a new unit at NAPS with and without refueling of the operating units.	The Kinetic Triathlon Special Event Population = 1,100 additional transients.
Evacuation Cases	27 Regions (central sector wind direction and each adjacent sector technique used) and 14 Scenarios producing 378 unique cases.	41 Regions (central sector wind direction and each adjacent sector technique used) and 14 Scenarios producing 574 unique cases.
Evacuation Time Estimates Reporting	ETE reported for 50th, 90th, 95th, and 100th percentile population. Results presented by Region and Scenario.	ETE reported for 90^{th} and 100^{th} percentile population. Results presented by Region and Scenario.
Evacuation Time Estimates for the entire EPZ, 90^{th} percentile	Winter Weekday Midday, Good weather = 2:50 Summer Weekend Midday, Good weather = 3:00	Winter Weekday Midday, Good Weather = 2:40 Summer Weekend, Midday, Good Weather = 2:00

2 STUDY ESTIMATES AND ASSUMPTIONS

This section presents the estimates and assumptions utilized in the development of the evacuation time estimates.

2.1 Data Estimates

1. Population estimates are based upon Census 2010 data.
2. Estimates of employees who reside outside the EPZ and commute to work within the EPZ are based upon data provided by Dominion and data obtained from a telephone call to the other major employer in the EPZ, Tri-Dim Filters.
3. Population estimates at special facilities are based on available data from county emergency management departments and from phone calls to specific facilities.
4. Roadway capacity estimates are based on field surveys and the application of the Highway Capacity Manual 2010.
5. Population mobilization times are based on a statistical analysis of data acquired from a random sample telephone survey of EPZ residents (see Section 5 and Appendix F).
6. The relationship between resident population and evacuating vehicles is developed from the telephone survey. Average values of 2.57 persons per household and 1.42 evacuating vehicles per household are used. The relationship between persons and vehicles for transients and employees is as follows:
    a. Employees: 1.04 employees per vehicle (telephone survey results) for all major employers.
    b. Recreational areas: Vehicle occupancy varies based upon data gathered from local transient facilities.
    c. Special Events: Kinetic Triathlon at Lake Anna State Park includes 1,100 additional transients traveling in 249 vehicles, equating to an occupancy of 4.4 people/vehicle.

2.2 Study Methodological Assumptions

1. ETE are presented for the evacuation of the 90th and 100th percentiles of population for each Region and for each Scenario. The percentile ETE is defined as the elapsed time from the Advisory to Evacuate issued to a specific Region of the EPZ, to the time that Region is clear of the indicated percentile of evacuees. A Region is defined as a group of PAZ that is issued an Advisory to Evacuate. A scenario is a combination of circumstances, including time of day, day of week, season, and weather conditions.
2. The ETE are computed and presented in tabular format and graphically, in a format compliant with NUREG/CR-7002.
3. Evacuation movements (paths of travel) are generally outbound relative to the plant to the extent permitted by the highway network. All major evacuation routes are used in the analysis.
4. Regions are defined by the underlying “keyhole” or circular configurations as specified in Section 1.4 of NUREG/CR-7002. These Regions, as defined, display irregular boundaries reflecting the geography of the PAZ included within these underlying configurations.
5. As indicated in Figure 2-2 of NUREG/CR-7002, 100% of people within the impacted “keyhole” evacuate. 20% of those people within the EPZ, not within the impacted keyhole, will voluntarily evacuate. 20% of those people within the Shadow Region will voluntarily evacuate. See Figure 2-1 for a graphical representation of these evacuation percentages. Sensitivity studies explore the effect on ETE of increasing the percentage of voluntary evacuees in the Shadow Region (see Appendix M).
6. A total of 14 “Scenarios” representing different temporal variations (season, time of day, day of week) and weather conditions are considered. These Scenarios are outlined in Table 2-1.
7. Scenario 14 considers the closure of a northbound segment of US-522 north of the intersection with CR-612.
8. The models of the I-DYNEV System were recognized as state of the art by the Atomic Safety & Licensing Board (ASLB) in past hearings. (Sources: Atomic Safety & Licensing Board Hearings on Seabrook and Shoreham; Urbanik[1]). The models have continuously been refined and extended since those hearings and were independently validated by a consultant retained by the NRC. The new DYNEV II model incorporates the latest technology in traffic simulation and in dynamic traffic assignment.

[1] Urbanik, T., et. al. Benchmark Study of the I-DYNEV Evacuation Time Estimate Computer Code, NUREG/CR-4873, Nuclear Regulatory Commission, June, 1988.

Table 2-1. Evacuation Scenario Definitions

Scenario	Season[2]	Day of Week	Time of Day	Weather	Special
1	Summer	Midweek	Midday	Good	None
2	Summer	Midweek	Midday	Rain	None
3	Summer	Weekend	Midday	Good	None
4	Summer	Weekend	Midday	Rain	None
5	Summer	Midweek, Weekend	Evening	Good	None
6	Winter	Midweek	Midday	Good	None
7	Winter	Midweek	Midday	Rain	None
8	Winter	Midweek	Midday	Snow	None
9	Winter	Weekend	Midday	Good	None
10	Winter	Weekend	Midday	Rain	None
11	Winter	Weekend	Midday	Snow	None
12	Winter	Midweek, Weekend	Evening	Good	None
13	Winter	Weekend	Midday	Good	Kinetic Triathlon at Lake Anna State Park
14	Summer	Midweek	Midday	Good	Roadway Impact – One Segment of US-522 NB will be Closed

[2] Winter assumes that school is in session (also applies to spring and autumn). Summer assumes that school is not in session.

Figure 2-1. Voluntary Evacuation Methodology

2.3 Study Assumptions

1. The Planning Basis Assumption for the calculation of ETE is a rapidly escalating accident that requires evacuation, and includes the following:
    a. Advisory to Evacuate is announced coincident with the siren notification.
    b. Mobilization of the general population will commence within 15 minutes after siren notification.
    c. ETE are measured relative to the Advisory to Evacuate.
2. It is assumed that everyone within the group of PAZ forming a Region that is issued an Advisory to Evacuate will, in fact, respond and evacuate in general accord with the planned routes.
3. 59 percent of the households in the EPZ have at least 1 commuter; 61 percent of those households with commuters will await the return of a commuter before beginning their evacuation trip, based on the telephone survey results. Therefore 36 percent (59% x 61% = 36%) of EPZ households will await the return of a commuter, prior to beginning their evacuation trip.
4. The ETE will also include consideration of "through" (External-External) trips during the time that such traffic is permitted to enter the evacuated Region. "Normal" traffic flow is assumed to be present within the EPZ at the start of the emergency.
5. Access Control Points (ACP) will be staffed within approximately 120 minutes following the siren notifications, to divert traffic attempting to enter the EPZ. Earlier activation of ACP locations could delay returning commuters. It is assumed that no through traffic will enter the EPZ after this 120 minute time period.
6. Traffic Control Points (TCP) within the EPZ will be staffed over time, beginning at the Advisory to Evacuate. Their number and location will depend on the Region to be evacuated and resources available. The objectives of these TCP are:
    a. Facilitate the movements of all (mostly evacuating) vehicles at the location.
    b. Discourage inadvertent vehicle movements towards the plant.
    c. Provide assurance and guidance to any traveler who is unsure of the appropriate actions or routing.
    d. Act as local surveillance and communications center.
    e. Provide information to the emergency operations center (EOC) as needed, based on direct observation or on information provided by travelers.

    In calculating ETE, it is assumed that evacuees will drive safely, travel in directions identified in the plan, and obey all control devices and traffic guides.

7. Buses will be used to transport those without access to private vehicles:
    a. If schools are in session, transport (buses) will evacuate students directly to the designated Evacuation Assembly Centers (EAC).
    b. It is assumed parents will pick up children at day care centers prior to evacuation.
    c. Buses, wheelchair vans and ambulances will evacuate patients at medical facilities and at any senior facilities within the EPZ, as needed.
    d. Transit-dependent general population will be evacuated to EAC.
    e. Schoolchildren, if school is in session, are given priority in assigning transit vehicles.
    f. Bus mobilization time is considered in ETE calculations.
    g. Analysis of the number of required round-trips ("waves") of evacuating transit vehicles is presented.
    h. Transport of transit-dependent evacuees from reception centers to congregate care centers is not considered in this study.
8. Provisions are made for evacuating the transit-dependent portion of the general population to EAC by bus, based on the assumption that some of these people will ride-share with family, neighbors, and friends, thus reducing the demand for buses. We assume that the percentage of people who rideshare is 50 percent. This assumption is based upon reported experience for other emergencies[3], and on guidance in Section 2.2 of NUREG/CR-7002.
9. Two types of adverse weather scenarios are considered. Rain may occur for either winter or summer scenarios; snow occurs in winter scenarios only. It is assumed that the rain or snow begins earlier or at about the same time the evacuation advisory is issued. No weather-related reduction in the number of transients who may be present in the EPZ is assumed. It is assumed that roads are passable and that the appropriate agencies are plowing the roads as they would normally when snowing.

   Adverse weather scenarios affect roadway capacity and the free flow highway speeds. The factors applied for the ETE study are based on recent research on the effects of weather on roadway operations[4]; the factors are shown in Table 2-2.

[3] Institute for Environmental Studies, University of Toronto, THE MISSISSAUGA EVACUATION FINAL REPORT, June 1981. The report indicates that 6,600 people of a transit-dependent population of 8,600 people shared rides with other residents; a ride share rate of 76% (Page 5-10).

[4] Agarwal, M. et. Al. Impacts of Weather on Urban Freeway Traffic Flow Characteristics and Facility Capacity, Proceedings of the 2005 Mid-Continent Transportation Research Symposium, August, 2005. The results of this paper are included as Exhibit 10-15 in the HCM 2010.

10. School buses used to transport students are assumed to transport 70 students per bus for elementary schools and 50 students per bus for middle and high schools, based on discussions with county offices of emergency management. Transit buses used to transport the transit-dependent general population are assumed to transport 30 people per bus.

Table 2-2. Model Adjustment for Adverse Weather

Scenario	Highway Capacity*	Free Flow Speed*	Mobilization Time for General Population
Rain	90%	90%	No Effect
Snow	80%	80%	Clear driveway before leaving home (See Figure F-13)
*Adverse weather capacity and speed values are given as a percentage of good weather conditions. Roads are assumed to be passable.			

3 DEMAND ESTIMATION

The estimates of demand, expressed in terms of people and vehicles, constitute a critical element in developing an evacuation plan. These estimates consist of three components:

1. An estimate of population within the EPZ, stratified into groups (resident, employee, transient).
2. An estimate, for each population group, of mean occupancy per evacuating vehicle. This estimate is used to determine the number of evacuating vehicles.
3. An estimate of potential double-counting of vehicles.

Appendix E presents much of the source material for the population estimates. Our primary source of population data, the 2010 Census, however, is not adequate for directly estimating some transient groups.

Throughout the year, vacationers and tourists enter the EPZ. These non-residents may dwell within the EPZ for a short period (e.g. a few days or one or two weeks), or may enter and leave within one day. Estimates of the size of these population components must be obtained, so that the associated number of evacuating vehicles can be ascertained.

The potential for double-counting people and vehicles must be addressed. For example:

- A resident who works and shops within the EPZ could be counted as a resident, again as an employee and once again as a shopper.
- A visitor who stays at a hotel and spends time at a park, then goes shopping could be counted three times.

Furthermore, the number of vehicles at a location depends on time of day. For example, motel parking lots may be full at dawn and empty at noon. Similarly, parking lots at area parks, which are full at noon, may be almost empty at dawn. Estimating counts of vehicles by simply adding up the capacities of different types of parking facilities will tend to overestimate the number of transients and can lead to ETE that are too conservative.

Analysis of the population characteristics of the North Anna Power Station EPZ indicates the need to identify three distinct groups:

- Permanent residents - people who are year round residents of the EPZ.
- Transients - people who reside outside of the EPZ who enter the area for a specific purpose (shopping, recreation) and then leave the area.
- Seasonal residents – people who are residents of the EPZ during the summer months but are not included in the permanent resident census numbers.
- Employees - people who reside outside of the EPZ and commute to businesses within the EPZ on a daily basis.

Estimates of the population and number of evacuating vehicles for each of the population groups are presented for each PAZ and by polar coordinate representation (population rose). The NAPS EPZ is subdivided into 25 PAZ. The EPZ is shown in Figure 3-1.

3.1 Permanent Residents

The primary source for estimating permanent population is the latest U.S. Census data. The average household size (2.57 persons/household – See Figure F-1) and the number of evacuating vehicles per household (1.42 vehicles/household – See Figure F-8) were adapted from the telephone survey results.

Population estimates are based upon Census 2010 data. The estimates are created by cutting the census block polygons by the PAZ and EPZ boundaries. A ratio of the original area of each census block and the updated area (after cutting) is multiplied by the total block population to estimate what the population is within the EPZ. This methodology assumes that the population is evenly distributed across a census block. Table 3-1 provides the permanent resident population within the EPZ, by PAZ based on this methodology.

The year 2010 permanent resident population is divided by the average household size and then multiplied by the average number of evacuating vehicles per household in order to estimate number of vehicles. Permanent resident population and vehicle estimates are presented in Table 3-2. Figure 3-2 and Figure 3-3 present the permanent resident population and permanent resident vehicle estimates by sector and distance from NAPS. This "rose" was constructed using GIS software.

It can be argued that this estimate of permanent residents overstates, somewhat, the number of evacuating vehicles, especially during the summer. It is certainly reasonable to assert that some portion of the population would be on vacation during the summer and would travel elsewhere. A rough estimate of this reduction can be obtained as follows:

- Assume 50 percent of all households vacation for a two-week period over the summer.
- Assume these vacations, in aggregate, are uniformly dispersed over 10 weeks, i.e. 10 percent of the population is on vacation during each two-week interval.
- Assume half of these vacationers leave the area.

On this basis, the permanent resident population would be reduced by 5 percent in the summer and by a lesser amount in the off-season. Given the uncertainty in this estimate, we elected to apply no reductions in permanent resident population for the summer scenarios to account for residents who may be out of the area.

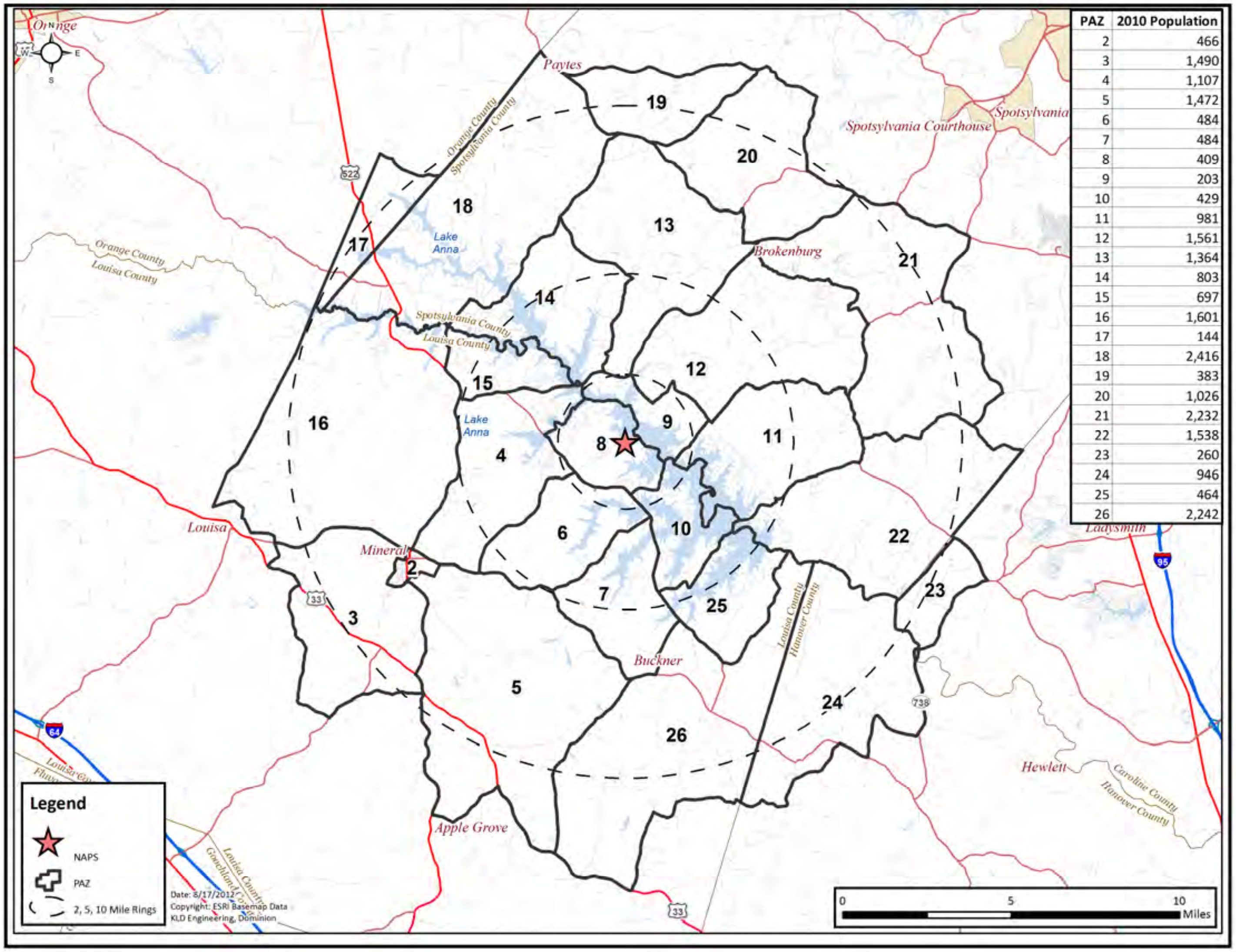


Figure 3-1. NAPS EPZ

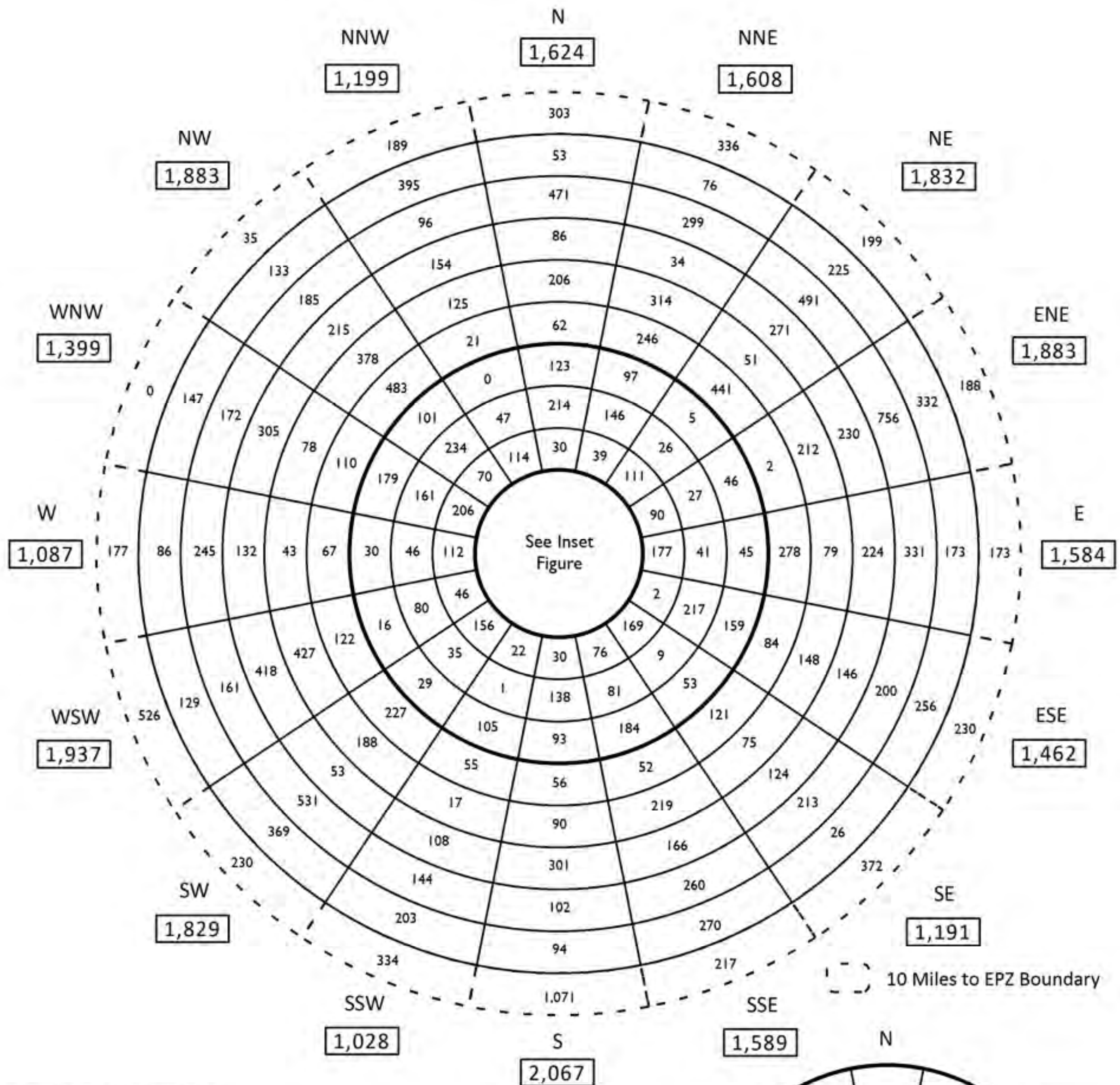
Table 3-1. EPZ Permanent Resident Population

PAZ	2000 Population	2008 Population (Estimated)[1]	2010 Population
2	418	645	466
3	1,241	1,843	1,490
4	837	1,842	1,107
5	1,331	1,740	1,472
6	308	727	484
7	318	939	484
8	287	885	409
9	117	426	203
10	245	1,151	429
11	740	1,345	981
12	1,222	1,467	1,561
13	991	1,312	1,364
14	541	1,719	803
15	451	1,589	697
16	1,138	2,153	1,601
17	50	223	144
18	1,664	3,624	2,416
19	246	352	383
20	894	1,025	1,026
21	1,901	2,125	2,232
22	1,355	1,639	1,538
23	263	341	260
24	716	989	946
25	312	902	464
26	1,729	2,420	2,242
TOTAL	**19,315**	**33,423**	**25,202**
EPZ Population Growth:		**2000-2010**	**30.48%**
EPZ Population Difference:		**2008-2010**	**-24.60%**

Notes: 1 - 2008 COLA ETE – Resident address points within each county (except Caroline County) were provided by VDEM. Average household size from telephone survey (2.57) was used to determine 2008 EPZ population. 2000 Census projected to 2008 using county growth rate was used for Caroline County.

Table 3-2. Permanent Resident Population and Vehicles by PAZ

PAZ	2010 Population	2010 Resident Vehicles
2	466	259
3	1,490	826
4	1,107	613
5	1,472	817
6	484	266
7	484	267
8	409	228
9	203	113
10	429	236
11	981	543
12	1,561	861
13	1,364	754
14	803	444
15	697	385
16	1,601	889
17	144	79
18	2,416	1,333
19	383	212
20	1,026	568
21	2,232	1,239
22	1,538	818
23	260	144
24	946	525
25	464	257
26	2,242	1,239
TOTAL	**25,202**	**13,915**



Resident Population

Miles	Subtotal by Ring	Cumulative Total
0 - 1	12	12
1 - 2	724	736
2 - 3	1,450	2,186
3 - 4	1,503	3,689
4 - 5	1,265	4,954
5 - 6	2,427	7,381
6 - 7	2,650	10,031
7 - 8	2,967	12,998
8 - 9	4,657	17,655
9 - 10	2,967	20,622
10 - EPZ	4,580	25,202
	Total:	25,202

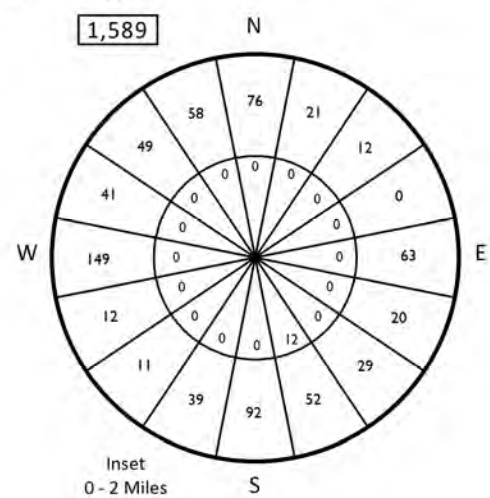
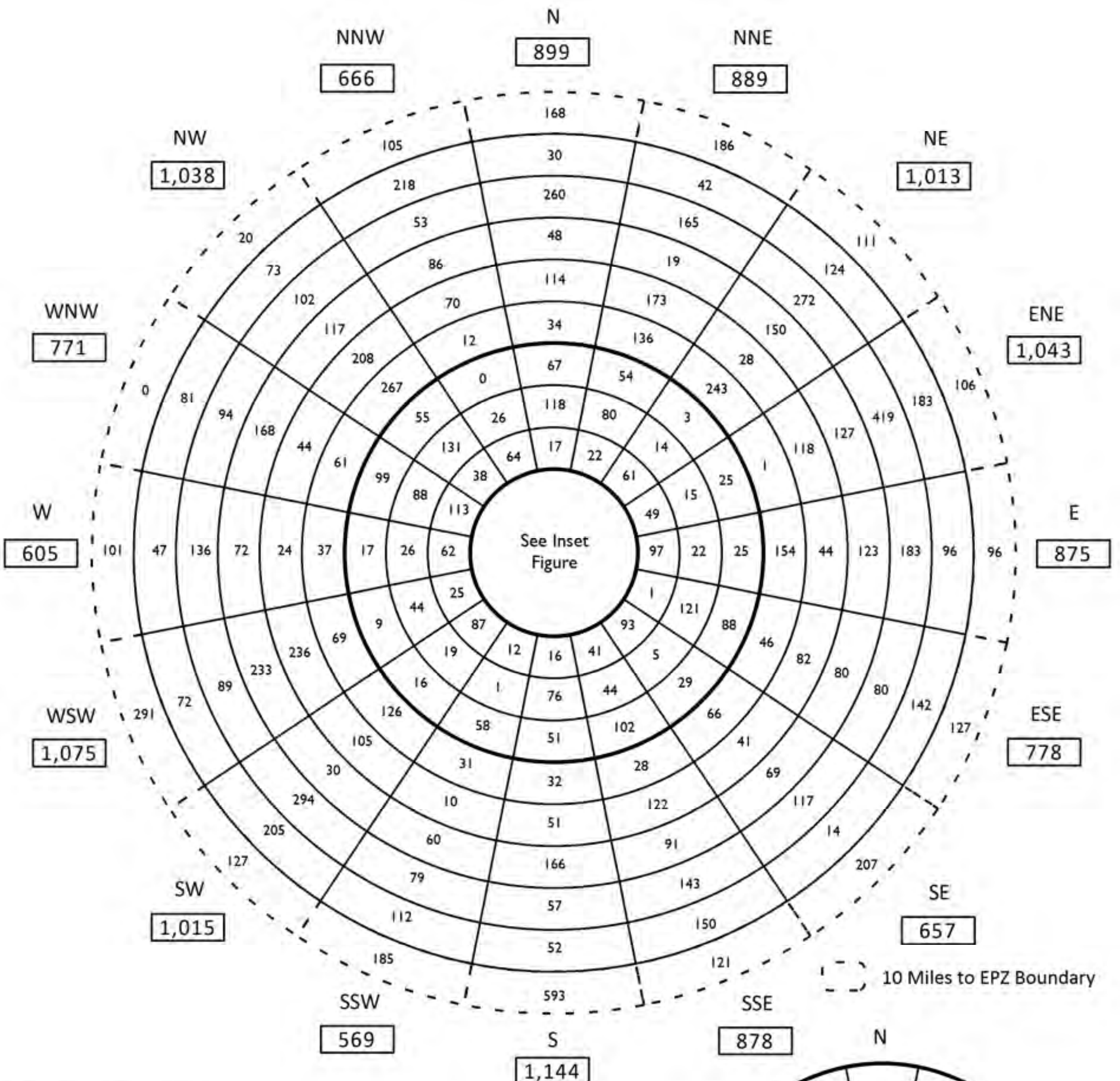


Figure 3-2. Permanent Resident Population by Sector



Resident Vehicles

Miles	Subtotal by Ring	Cumulative Total
0 - 1	7	7
1 - 2	402	409
2 - 3	798	1,207
3 - 4	830	2,037
4 - 5	698	2,735
5 - 6	1,343	4,078
6 - 7	1,470	5,548
7 - 8	1,639	7,187
8 - 9	2,543	9,730
9 - 10	1,641	11,371
10 - EPZ	2,544	13,915
	Total:	13,915

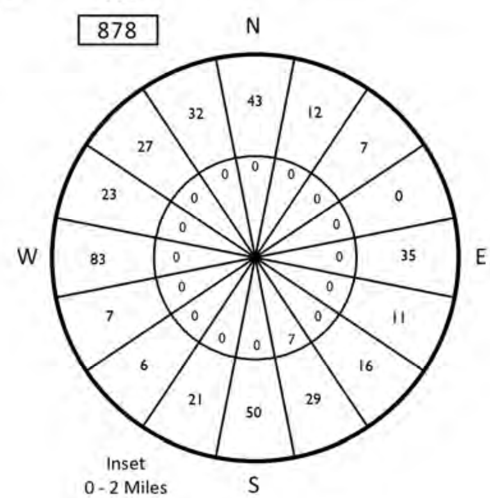


Figure 3-3. Permanent Resident Vehicles by Sector

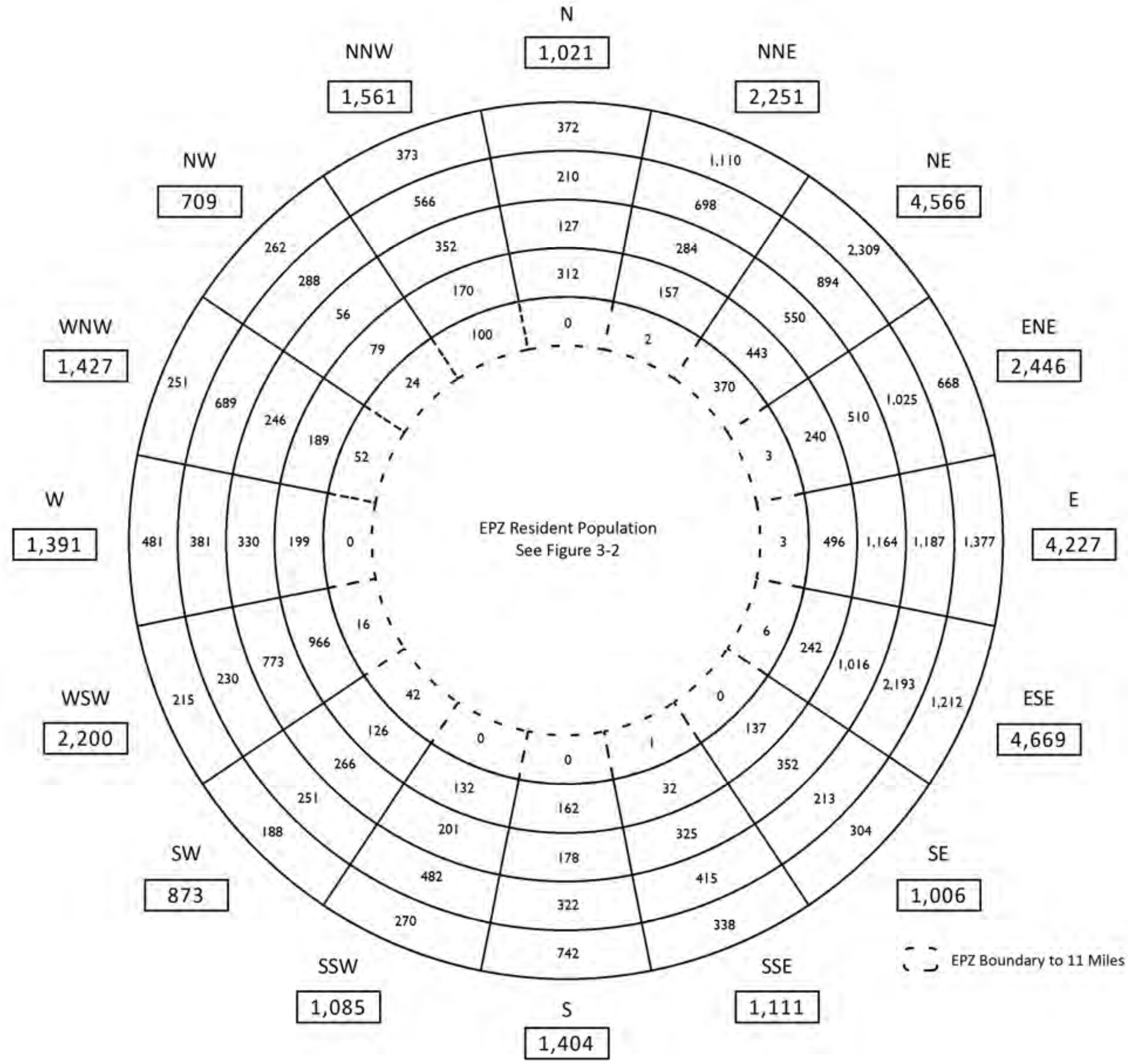
3.2 Shadow Population

A portion of the population living outside the evacuation area extending to 15 miles radially from the NAPS (in the Shadow Region) may elect to evacuate without having been instructed to do so. Based upon NUREG/CR-7002 guidance, it is assumed that 20 percent of the permanent resident population, based on U.S. Census Bureau data, in this Shadow Region will elect to evacuate.

Shadow population characteristics (household size, evacuating vehicles per household, mobilization time) are assumed to be the same as that for the EPZ permanent resident population. Table 3-3, Figure 3-4, and Figure 3-5 present estimates of the shadow population and vehicles, by sector.

Table 3-3. Shadow Population and Vehicles by Sector

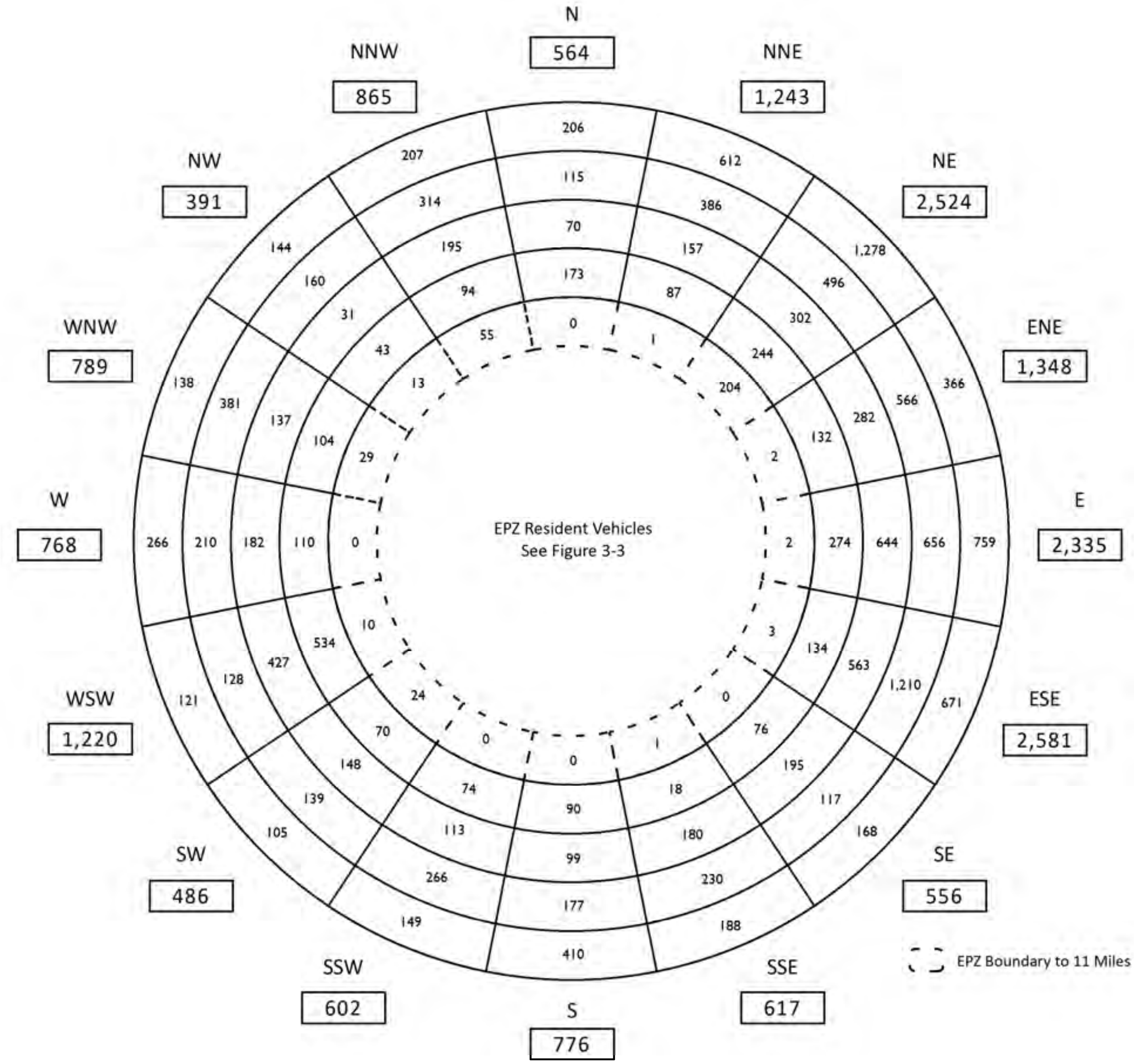
Sector	Population	Evacuating Vehicles
N	1,021	564
NNE	2,251	1,243
NE	4,566	2,524
ENE	2,446	1,348
E	4,227	2,335
ESE	4,669	2,581
SE	1,006	556
SSE	1,111	617
S	1,404	776
SSW	1,085	602
SW	873	486
WSW	2,200	1,220
W	1,391	768
WNW	1,427	789
NW	709	391
NNW	1,561	865
TOTAL	**31,947**	**17,665**



Shadow Population

Miles	Subtotal by Ring	Cumulative Total
EPZ - 11	619	619
11 - 12	4,082	4,701
12 - 13	6,730	11,431
13 - 14	10,044	21,475
14 - 15	10,472	31,947
	Total:	31,947

Figure 3-4. Shadow Population by Sector



Shadow Vehicles

Miles	Subtotal by Ring	Cumulative Total
EPZ - 11	344	344
11 - 12	2,257	2,601
12 - 13	3,725	6,326
13 - 14	5,551	11,877
14 - 15	5,788	17,665
	Total:	17,665

Figure 3-5. Shadow Vehicles by Sector

3.3 Transient Population

Transient population groups are defined as those people (who are not permanent residents, nor commuting employees) who enter the EPZ for a specific purpose (shopping, recreation). Transients may spend less than one day or stay overnight at camping facilities, hotels and motels. The NAPS EPZ has a number of areas and facilities that attract transients, including:

- Campgrounds
- State Parks
- Marinas
- Lodging Facilities
- Seasonal Summer Homes on Lake Anna

Data were gathered through phone calls placed to individual facilities within the EPZ. Data from the 2008 ETE report (Revision 1 of the 2007 COLA) was used for facilities where data was unable to be collected.

There are two campgrounds within the EPZ. Phone calls were made to determine the number of campsites, peak occupancy and the number of vehicles and people per campsite for each facility. Data from the 2008 ETE report was used for Christopher Run Campground in Mineral. A total of 2,298 transients and 899 vehicles are assigned to campgrounds in the EPZ.

Data gathered from Lake Anna State Park were used to estimate the number of transients and evacuating vehicles at this facility. A total of 1,920 transients and 480 vehicles are assigned to this facility.

There are seven marinas within the EPZ. Phone calls were made to determine the peak season and peak daily attendance. These data were used to estimate the number of transients and evacuating vehicles at each of these facilities. Data from the 2008 ETE report was used for High Point Marina. A total of 994 transients and 456 vehicles are assigned to this facility.

There are four lodging facilities (all smaller hotels/bed and breakfasts) within the EPZ. Phone calls were made to determine the number of rooms, percentage of occupied rooms at peak times and the number of people and vehicles per room for each facility. These data were used to estimate the number of transients and evacuating vehicles at each of these facilities. Data from the 2008 ETE report was used for Rockland Farm Retreat. A total of 61 transients and 44 vehicles are assigned to lodging facilities in the EPZ.

Appendix E summarizes the transient data that was estimated for the EPZ. Table E-4 presents the number of transients visiting marinas within the EPZ, Table E-5 presents the number of transients at visiting campground within the EPZ, Table E-6 presents the number of transients visiting State Parks within the EPZ and Table E-7 presents the number of transients visiting lodging facilities within the EPZ.

The NAPS EPZ has a secondary category of transient population which is seasonal residents. These people will enter the area during the summer months and may stay considerably longer (several weeks or the entire season) than the average transient using a hotel or motel. The seasonal population use other lodging facilities such as condos, beach houses and summer rentals that otherwise would not be captured in a typical lodging population.

The methodology behind calculating the seasonal population involves using 2010 Census Block data. Each Census Block includes information regarding the number of vacant and occupied households. Using this Census data, an average vacant household percentage (23%) was calculated for the entire NAPS EPZ.

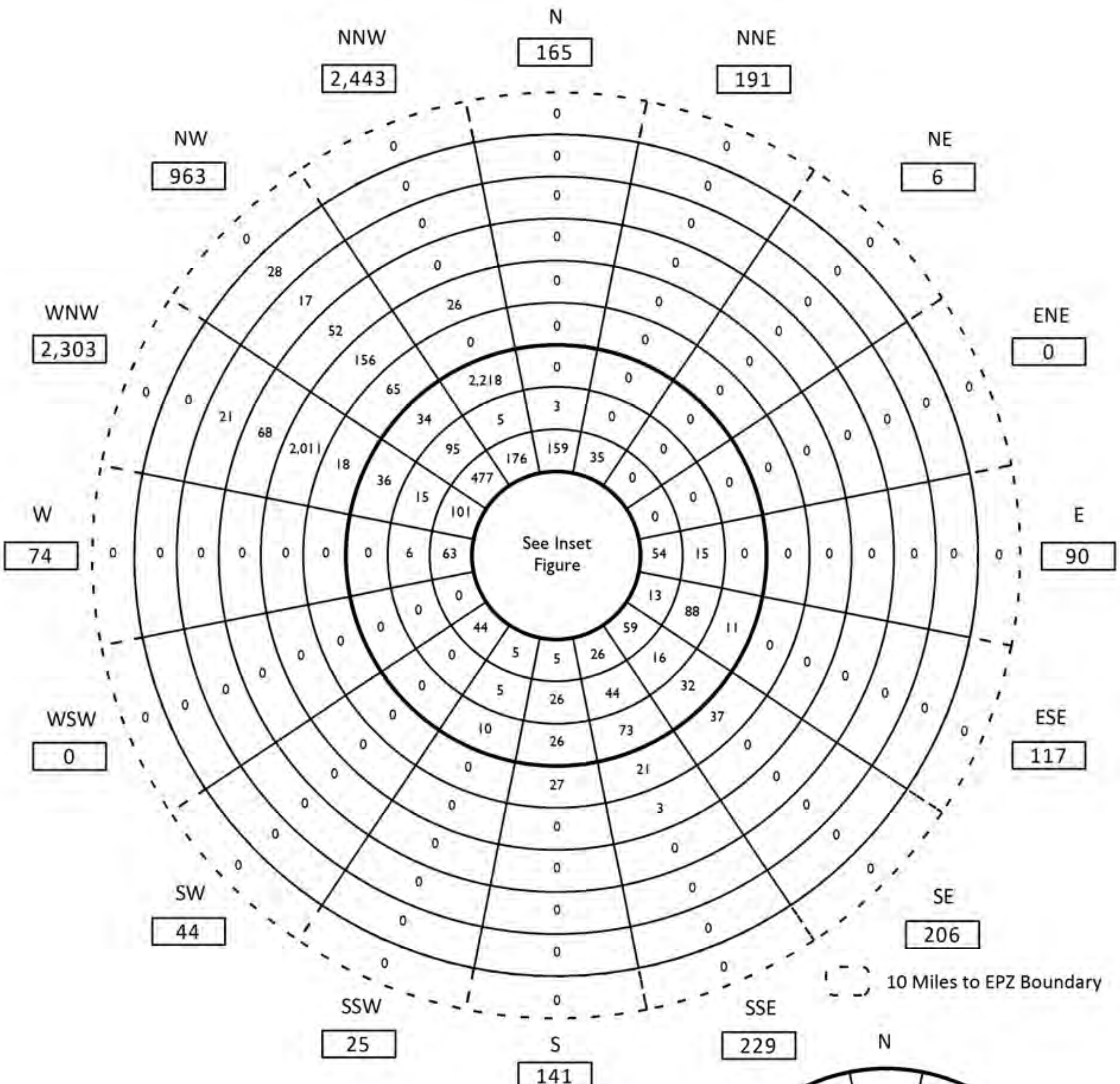
It is assumed that seasonal residents will be renting homes near the Lake Anna shoreline. Using only those Census blocks that are within one-half mile of the shoreline, the number of seasonal homes will be calculated. In order to normalize the data, the average vacant household percentage for the entire EPZ (23%) was subtracted from the percent vacancy for each individual census block. To determine the seasonal population, the remaining households from the analysis are considered to be seasonal households. An average household size of 2.57 persons per household is used to determine the seasonal transient population, and 1.42 evacuating vehicles per seasonal household is used to determine the number of seasonal transient vehicles. These numbers are adapted from the telephone survey results (see Appendix F).

It is estimated that there is an additional seasonal population of 1,724 transients traveling in 922 vehicles within the NAPS EPZ. Factoring in seasonal transients, there are a total of 6,997 (5,273+1,724) transients traveling in 2,801 vehicles (1,879+922) within the NAPS EPZ. These numbers are included in Table 3-4 as well as Figure 3-6 and Figure 3-7.

Table 3-4 presents transient population and transient vehicle estimates by PAZ. Figure 3-6 and Figure 3-7 present these data by sector and distance from the plant.

Table 3-4. Summary of Transients and Transient Vehicles

PAZ	Transients	Transient Vehicles	Seasonal Transients	Seasonal Transient Vehicles
2	0	0	0	0
3	0	0	0	0
4	0	0	165	87
5	0	0	0	0
6	0	0	72	40
7	0	0	102	54
8	0	0	213	118
9	150	100	36	16
10	0	0	231	125
11	58	24	128	68
12	167	58	3	1
13	27	27	0	0
14	2,773	831	104	56
15	0	0	262	145
16	2,000	800	74	38
17	0	0	5	3
18	98	39	197	103
19	0	0	0	0
20	0	0	0	0
21	0	0	0	0
22	0	0	8	4
23	0	0	0	0
24	0	0	0	0
25	0	0	124	64
26	0	0	0	0
TOTAL	**5,273**	**1,879**	**1,724**	**922**



Transients

Miles	Subtotal by Ring	Cumulative Total
0 - 1	5	5
1 - 2	467	472
2 - 3	1,217	1,689
3 - 4	318	2,007
4 - 5	2,440	4,447
5 - 6	168	4,615
6 - 7	2,196	6,811
7 - 8	120	6,931
8 - 9	38	6,969
9 - 10	28	6,997
10 - EPZ	0	6,997
	Total:	6,997

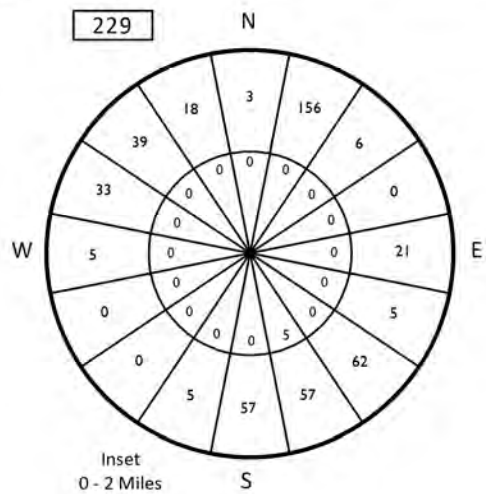
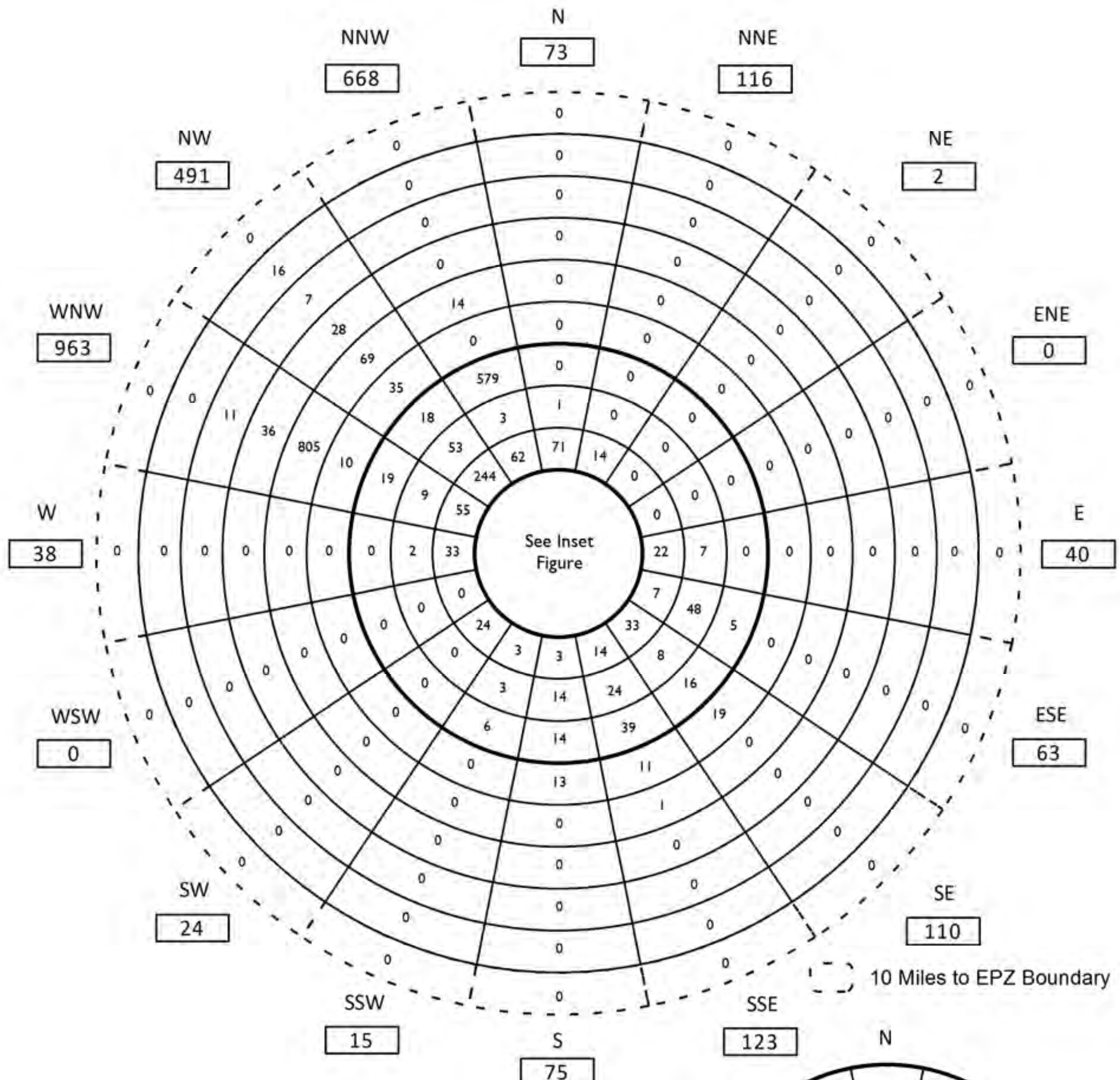


Figure 3-6. Transient Population by Sector



Transient Vehicles

Miles	Subtotal by Ring	Cumulative Total
0 - 1	3	3
1 - 2	270	273
2 - 3	585	858
3 - 4	172	1,030
4 - 5	696	1,726
5 - 6	88	1,814
6 - 7	889	2,703
7 - 8	64	2,767
8 - 9	18	2,785
9 - 10	16	2,801
10 - EPZ	0	2,801
	Total:	2,801

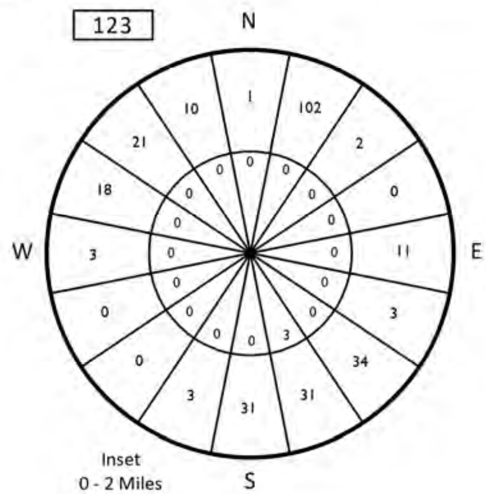


Figure 3-7. Transient Vehicles by Sector

3.4 Employees

Employees who work within the EPZ fall into two categories:

- Those who live and work in the EPZ
- Those who live outside of the EPZ and commute to jobs within the EPZ.

Those of the first category are already counted as part of the permanent resident population. To avoid double counting, we focus only on those employees commuting from outside the EPZ who will evacuate along with the permanent resident population.

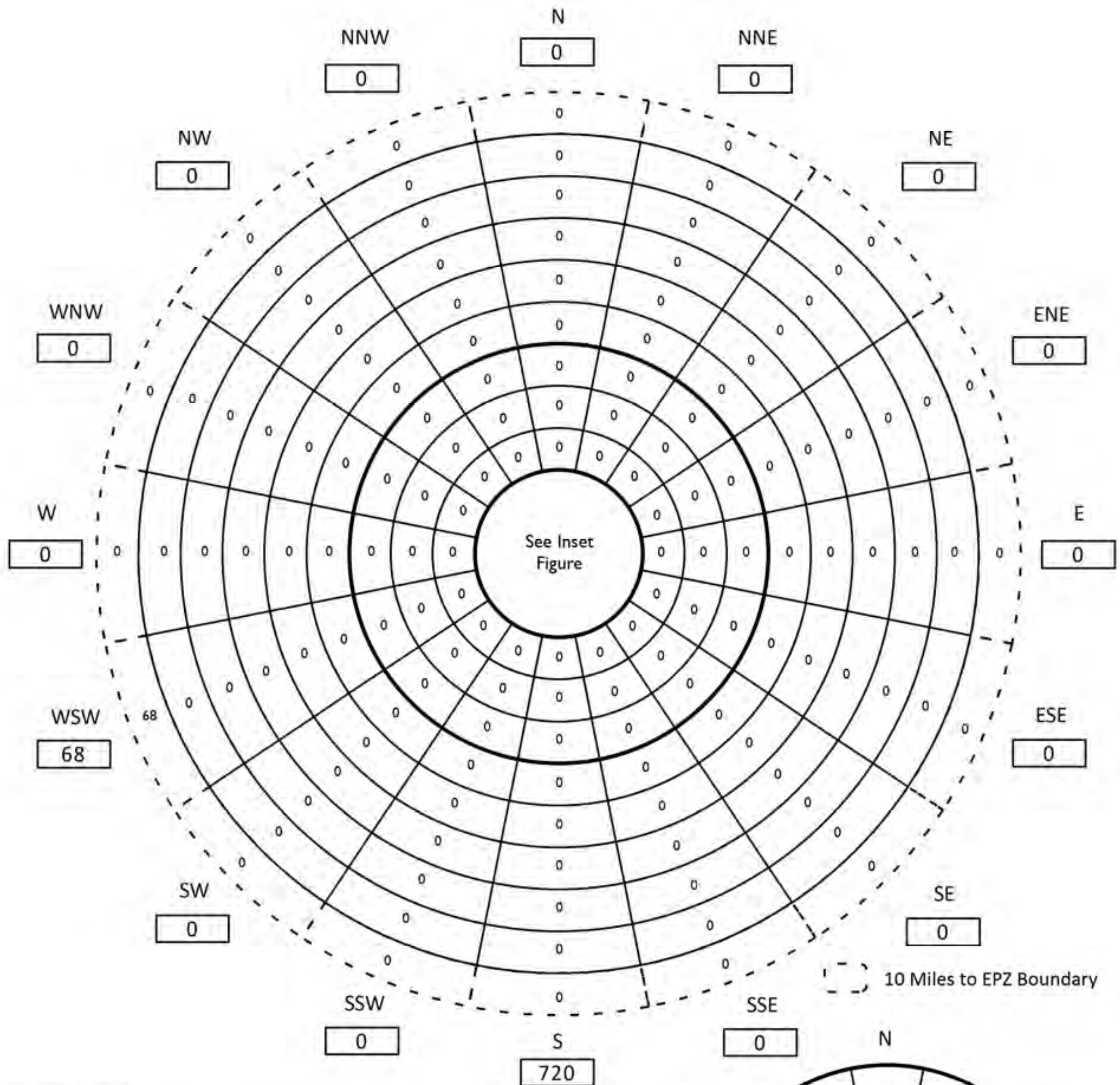
There are two major employers within the EPZ, North Anna Power Station and Tri-Dim Filters. Data provided by Dominion and a phone call made to Tri-Dim Filters were used to estimate the number of employees commuting into the EPZ.

In Table E-3, the Employees (Max Shift) is multiplied by the percent Non-EPZ factor to determine the number of employees who are not residents of the EPZ. A vehicle occupancy of 1.04 employees per vehicle obtained from the telephone survey (See Figure F-7) was used to determine the number of evacuating employee vehicles for all major employers.

Table 3-5 presents non-EPZ Resident employee and vehicle estimates by PAZ. Figure 3-8 and Figure 3-9 present these data by sector.

Table 3-5. Summary of Non-EPZ Resident Employees and Employee Vehicles

PAZ	Employees	Employee Vehicles
2	0	0
3	68	65
4	0	0
5	0	0
6	0	0
7	0	0
8	720	692
9	0	0
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
18	0	0
19	0	0
20	0	0
21	0	0
22	0	0
23	0	0
24	0	0
25	0	0
26	0	0
TOTAL	**788**	**757**



Employees

Miles	Subtotal by Ring	Cumulative Total
0 - 1	720	720
1 - 2	0	720
2 - 3	0	720
3 - 4	0	720
4 - 5	0	720
5 - 6	0	720
6 - 7	0	720
7 - 8	0	720
8 - 9	0	720
9 - 10	0	720
10 - EPZ	68	788
	Total:	788

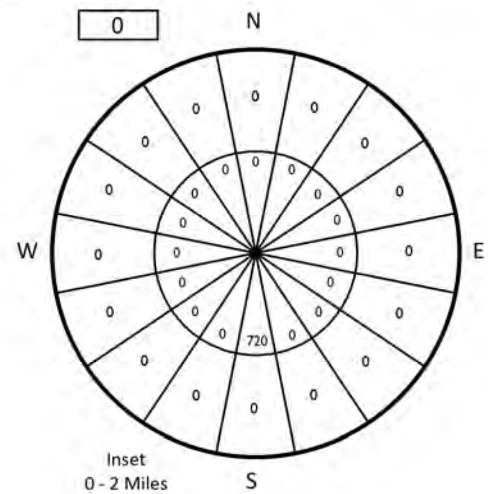
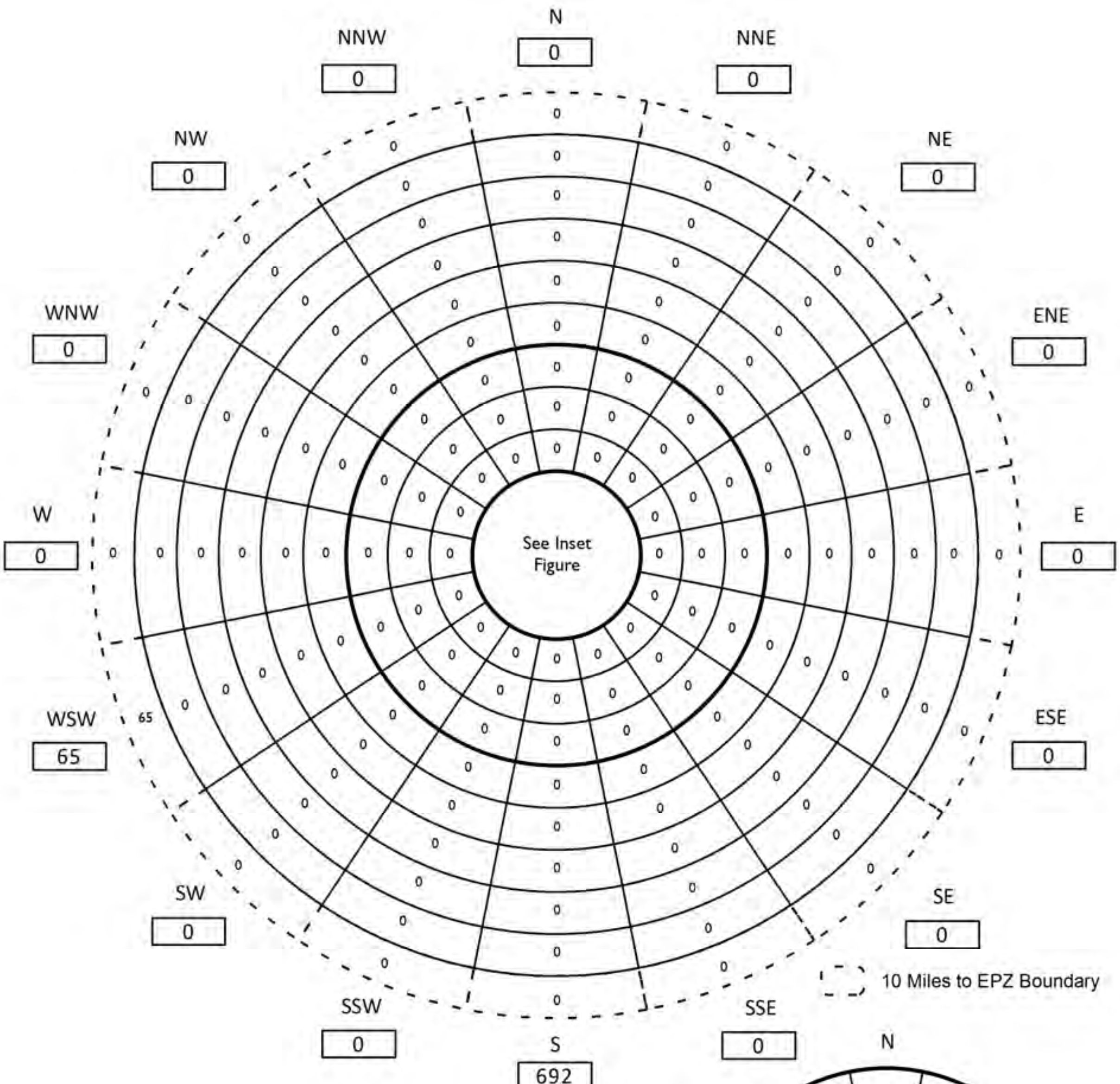


Figure 3-8. Employee Population by Sector



Employee Vehicles

Miles	Subtotal by Ring	Cumulative Total
0 - 1	692	692
1 - 2	0	692
2 - 3	0	692
3 - 4	0	692
4 - 5	0	692
5 - 6	0	692
6 - 7	0	692
7 - 8	0	692
8 - 9	0	692
9 - 10	0	692
10 - EPZ	65	757
	Total:	757

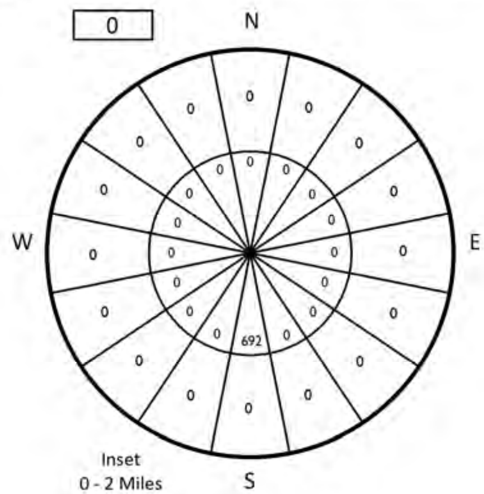


Figure 3-9. Employee Vehicles by Sector

3.5 Medical Facilities

A phone call was made to gather data for the one medical facility within the EPZ. Table E-2 in Appendix E summarizes the data gathered. Section 8 details the evacuation of medical facilities and their patients. The number and type of evacuating vehicles that need to be provided depend on the patients' state of health. It is estimated that buses can transport up to 30 people; and wheelchair vans, up to 4 people.

3.6 Total Demand in Addition to Permanent Population

Vehicles will be traveling through the EPZ (external-external trips) at the time of an accident. After the Advisory to Evacuate is announced, these through-travelers will also evacuate. These through vehicles are assumed to travel on major routes traversing the study area – US-1, Interstate-95 and Interstate-64. It is assumed that this traffic will continue to enter the study area during the first 120 minutes following the Advisory to Evacuate.

Average Annual Daily Traffic (AADT) data was obtained from VDOT[1] to estimate the number of vehicles per hour on the aforementioned routes. The AADT was multiplied by the K-Factor (obtained from VDOT), which is the proportion of the AADT on a roadway segment or link during the design hour, resulting in the design hour volume (DHV). The design hour is usually the 30th highest hourly traffic volume of the year, measured in vehicles per hour (vph). The DHV is then multiplied by the D-Factor (obtained from HCM 2010), which is the proportion of the DHV occurring in the peak direction of travel (also known as the directional split). The resulting values are the directional design hourly volumes (DDHV), and are presented in Table 3-6, for each of the routes considered. The DDHV is then multiplied by 2 hours (access control points – ACP – are assumed to be activated at 120 minutes after the advisory to evacuate) to estimate the total number of external vehicles loaded on the analysis network. As indicated, there are 13,550 vehicles entering the study area as external-external trips prior to the activation of access control and the diversion of this traffic. This number is reduced by 60% for evening scenarios (Scenarios 5 and 12) as discussed in Section 6.

3.7 Special Event

One special event (Scenario 13) is considered for the ETE study – the Kinetic Triathlon at Lake Anna State Park, which occurs annually on the second weekend in May. Data was gathered by calling the facility. This event attracts an additional 1,100 transients to the park, traveling in approximately 249 vehicles.

These vehicles are all loaded at the park and are included in Table 6-4 under Special Events. The special event vehicle trips were generated utilizing the same mobilization distributions as for transients. Public transportation is not provided for this event and was not considered in the special event analysis.

[1] http://www.virginiadot.org/info/2010_traffic_data.asp

Table 3-6. NAPS EPZ External Traffic

Upstream Node	Downstream Node	Road Name	Direction	VDOT[1] AADT	K-Factor[1]	D-Factor[2]	Hourly Volume	External[3] Traffic
8330	330	I-64	EB	14,000	0.1374	0.5	962	1,924
8329	329	I-64	WB	14,000	0.1237	0.5	866	1,732
8152	152	I-95	NB	44,000	0.1034	0.5	2,275	4,550
8146	146	I-95	SB	43,000	0.1012	0.5	2,176	4,352
8303	303	US-1	NB	5,300	0.0936	0.5	248	496
8265	265	US-1	SB	5,300	0.0936	0.5	248	496
							TOTAL	**13,550**

Notes: 1 - Virginia Department of Transportation (VDOT), 2010

2 - HCM 2010

3 - Interstate-64 and Interstate-95 are outside of the Shadow Region and only a small portion of US-1 resides in the Shadow Region

3.8 Summary of Demand

A summary of population and vehicle demand is provided in Table 3-7 and Table 3-8, respectively. This summary includes all population groups described in this section. Additional population groups – transit-dependent, special facility and school population – are described in greater detail in Section 8. A total of 46,186 people and 34,835 vehicles are considered in this study.

Table 3-7. Summary of Population Demand

PAZ	Residents	Transit-Dependent	Transients	Seasonal Transients	Employees	Special Facilities	Schools	Shadow Population	External Traffic	Total
2	466	7	0	0	0	0	60	0	0	533
3	1,490	21	0	0	68	23	3,010	0	0	4,612
4	1,107	16	0	165	0	0	0	0	0	1,288
5	1,472	21	0	0	0	0	597	0	0	2,090
6	484	7	0	72	0	0	0	0	0	563
7	484	7	0	102	0	0	0	0	0	593
8	409	6	0	213	720	0	0	0	0	1,348
9	203	3	150	36	0	0	0	0	0	392
10	429	6	0	231	0	0	0	0	0	666
11	981	14	58	128	0	0	0	0	0	1,181
12	1,561	22	167	3	0	0	444	0	0	2,197
13	1,364	19	27	0	0	0	0	0	0	1,410
14	803	11	2,773	104	0	0	0	0	0	3,691
15	697	10	0	262	0	0	0	0	0	969
16	1,601	23	2,000	74	0	0	0	0	0	3,698
17	144	2	0	5	0	0	0	0	0	151
18	2,416	34	98	197	0	0	0	0	0	2,745
19	383	5	0	0	0	0	0	0	0	388
20	1,026	15	0	0	0	0	0	0	0	1,041
21	2,232	32	0	0	0	0	2,316	0	0	4,580
22	1,538	22	0	8	0	0	0	0	0	1,568
23	260	4	0	0	0	0	0	0	0	264
24	946	14	0	0	0	0	0	0	0	960
25	464	7	0	124	0	0	0	0	0	595
26	2,242	32	0	0	0	0	0	0	0	2,274
Shadow	0	0	0	0	0	0	0	6,389	0	6,389
Total	**25,202**	**360**	**5,273**	**1,724**	**788**	**23**	**6,427**	**6,389**	**0**	**46,186**

Notes: - 20% Percent Shadow population evacuation. Refer to Figure 2-1 for additional information.
- Special Facilities column only consists of JABA Adult Daycare
- School population total includes enrollment for Jouett Elementary School, even though it shelters-in-place.

Table 3-8. Summary of Vehicle Demand

PAZ	Residents	Transit-Dependent	Transients	Seasonal Transients	Employees	Special Facilities	Schools	Shadow Population	External Traffic	Total
2	259	2	0	0	0	0	2	0	0	263
3	826	2	0	0	65	3	116	0	0	1,012
4	613	2	0	87	0	0	0	0	0	702
5	817	2	0	0	0	0	0	0	0	819
6	266	2	0	40	0	0	0	0	0	308
7	267	2	0	54	0	0	0	0	0	323
8	228	2	0	118	692	0	0	0	0	1,040
9	113	2	100	16	0	0	0	0	0	231
10	236	2	0	125	0	0	0	0	0	363
11	543	2	24	68	0	0	0	0	0	637
12	861	2	58	1	0	0	14	0	0	936
13	754	2	27	0	0	0	0	0	0	783
14	444	2	831	56	0	0	0	0	0	1,333
15	385	2	0	145	0	0	0	0	0	532
16	889	2	800	38	0	0	0	0	0	1,729
17	79	2	0	3	0	0	0	0	0	84
18	1,333	2	39	103	0	0	0	0	0	1,477
19	212	2	0	0	0	0	0	0	0	214
20	568	2	0	0	0	0	0	0	0	570
21	1,239	2	0	0	0	0	94	0	0	1,335
22	818	2	0	4	0	0	0	0	0	824
23	144	2	0	0	0	0	0	0	0	146
24	525	2	0	0	0	0	0	0	0	527
25	257	2	0	64	0	0	0	0	0	323
26	1,239	2	0	0	0	0	0	0	0	1,241
Shadow	0	0	0	0	0	0	0	3,533	13,550	17,083
Total	**13,915**	**50**	**1,879**	**922**	**757**	**3**	**226**	**3,533**	**13,550**	**34,835**

Notes: - Buses represented as two passenger vehicles. Refer to Section 8 for additional information.

4 ESTIMATION OF HIGHWAY CAPACITY

The ability of the road network to service vehicle demand is a major factor in determining how rapidly an evacuation can be completed. The capacity of a road is defined as the maximum hourly rate at which persons or vehicles can reasonably be expected to traverse a point or uniform section of a lane of roadway during a given time period under prevailing roadway, traffic and control conditions, as stated in the 2010 Highway Capacity Manual (HCM 2010).

In discussing capacity, different operating conditions have been assigned alphabetical designations, A through F, to reflect the range of traffic operational characteristics. These designations have been termed "Levels of Service" (LOS). For example, LOS A connotes free-flow and high-speed operating conditions; LOS F represents a forced flow condition. LOS E describes traffic operating at or near capacity.

Another concept, closely associated with capacity, is "Service Volume" (SV). Service volume is defined as "The maximum hourly rate at which vehicles, bicycles or persons reasonably can be expected to traverse a point or uniform section of a roadway during an hour under specific assumed conditions while maintaining a designated level of service." This definition is similar to that for capacity. The major distinction is that values of SV vary from one LOS to another, while capacity is the service volume at the upper bound of LOS E, only.

This distinction is illustrated in Exhibit 11-17 of the HCM 2010. As indicated there, the SV varies with Free Flow Speed (FFS), and LOS. The SV is calculated by the DYNEV II simulation model, based on the specified link attributes, FFS, capacity, control device and traffic demand.

Other factors also influence capacity. These include, but are not limited to:

- Lane width
- Shoulder width
- Pavement condition
- Horizontal and vertical alignment (curvature and grade)
- Percent truck traffic
- Control device (and timing, if it is a signal)
- Weather conditions (rain, snow, fog, wind speed, ice)

These factors are considered during the road survey and in the capacity estimation process; some factors have greater influence on capacity than others. For example, lane and shoulder width have only a limited influence on Base Free Flow Speed (BFFS[1]) according to Exhibit 15-7 of the HCM. Consequently, lane and shoulder widths at the narrowest points were observed during the road survey and these observations were recorded, but no detailed measurements of lane or shoulder width were taken. Horizontal and vertical alignment can influence both FFS and capacity. The estimated FFS were measured using the survey vehicle's speedometer and observing local traffic, under free flow conditions. Capacity is estimated from the procedures of

[1] A very rough estimate of BFFS might be taken as the posted speed limit plus 10 mph (HCM 2010 Page 15-15)

the 2010 HCM. For example, HCM Exhibit 7-1(b) shows the sensitivity of Service Volume at the upper bound of LOS D to grade (capacity is the Service Volume at the upper bound of LOS E).

As discussed in Section 2.3, it is necessary to adjust capacity figures to represent the prevailing conditions during inclement weather. Based on limited empirical data, weather conditions such as rain reduce the values of free speed and of highway capacity by approximately 10 percent. Over the last decade new studies have been made on the effects of rain on traffic capacity. These studies indicate a range of effects between 5 and 20 percent depending on wind speed and precipitation rates. As indicated in Section 2.3, we employ a reduction in free speed and in highway capacity of 10 percent and 20 percent for rain and snow, respectively.

Since congestion arising from evacuation may be significant, estimates of roadway capacity must be determined with great care. Because of its importance, a brief discussion of the major factors that influence highway capacity is presented in this section.

Rural highways generally consist of: (1) one or more uniform sections with limited access (driveways, parking areas) characterized by "uninterrupted" flow; and (2) approaches to at-grade intersections where flow can be "interrupted" by a control device or by turning or crossing traffic at the intersection. Due to these differences, separate estimates of capacity must be made for each section. Often, the approach to the intersection is widened by the addition of one or more lanes (turn pockets or turn bays), to compensate for the lower capacity of the approach due to the factors there that can interrupt the flow of traffic. These additional lanes are recorded during the field survey and later entered as input to the DYNEV II system.

4.1 Capacity Estimations on Approaches to Intersections

At-grade intersections are apt to become the first bottleneck locations under local heavy traffic volume conditions. This characteristic reflects the need to allocate access time to the respective competing traffic streams by exerting some form of control. During evacuation, control at critical intersections will often be provided by traffic control personnel assigned for that purpose, whose directions may supersede traffic control devices. The existing traffic management plans documented in the county emergency plans are extensive and were adopted without change.

The per-lane capacity of an approach to a signalized intersection can be expressed (simplistically) in the following form:

$$Q_{cap,m} = \left(\frac{3600}{h_m}\right) \times \left(\frac{G-L}{C}\right)_m = \left(\frac{3600}{h_m}\right) \times P_m$$

where:

$Q_{cap,m}$ = Capacity of a single lane of traffic on an approach, which executes movement, m, upon entering the intersection; vehicles per hour (vph)

h_m	=	Mean queue discharge headway of vehicles on this lane that are executing movement, m; seconds per vehicle
G	=	Mean duration of GREEN time servicing vehicles that are executing movement, m, for each signal cycle; seconds
L	=	Mean "lost time" for each signal phase servicing movement, m; seconds
C	=	Duration of each signal cycle; seconds
P_m	=	Proportion of GREEN time allocated for vehicles executing movement, m, from this lane. This value is specified as part of the control treatment.
m	=	The movement executed by vehicles after they enter the intersection: through, left-turn, right-turn, and diagonal.

The turn-movement-specific mean discharge headway h_m, depends in a complex way upon many factors: roadway geometrics, turn percentages, the extent of conflicting traffic streams, the control treatment, and others. A primary factor is the value of "saturation queue discharge headway", h_{sat}, which applies to through vehicles that are not impeded by other conflicting traffic streams. This value, itself, depends upon many factors including motorist behavior. Formally, we can write,

$$h_m = f_m(h_{sat}, F_1, F_2, \ldots)$$

where:

h_{sat}	=	Saturation discharge headway for through vehicles; seconds per vehicle
F_1, F_2	=	The various known factors influencing h_m
$f_m(\ )$	=	Complex function relating h_m to the known (or estimated) values of h_{sat}, F_1, F_2, …

The estimation of h_m for specified values of h_{sat}, F_1, F_2, … is undertaken within the DYNEV II simulation model by a mathematical model[2]. The resulting values for h_m always satisfy the condition:

$$h_m \geq h_{sat}$$

[2]Lieberman, E., "Determining Lateral Deployment of Traffic on an Approach to an Intersection", McShane, W. & Lieberman, E., "Service Rates of Mixed Traffic on the far Left Lane of an Approach". Both papers appear in Transportation Research Record 772, 1980. Lieberman, E., Xin, W., "Macroscopic Traffic Modeling For Large-Scale Evacuation Planning", presented at the TRB 2012 Annual Meeting, January 22-26, 2012

That is, the turn-movement-specific discharge headways are always greater than, or equal to the saturation discharge headway for through vehicles. These headways (or its inverse equivalent, "saturation flow rate"), may be determined by observation or using the procedures of the HCM 2010.

The above discussion is necessarily brief given the scope of this ETE report and the complexity of the subject of intersection capacity. In fact, Chapters 18, 19 and 20 in the HCM 2010 address this topic. The factors, F_1, F_2,…, influencing saturation flow rate are identified in equation (18-5) of the HCM 2010.

The traffic signals within the EPZ and Shadow Region are modeled using representative phasing plans and phase durations obtained as part of the field data collection. Traffic responsive signal installations allow the proportion of green time allocated (P_m) for each approach to each intersection to be determined by the expected traffic volumes on each approach during evacuation circumstances. The amount of green time (G) allocated is subject to maximum and minimum phase duration constraints; 2 seconds of yellow time are indicated for each signal phase and 1 second of all-red time is assigned between signal phases, typically. If a signal is pre-timed, the yellow and all-red times observed during the road survey are used. A lost time (L) of 2.0 seconds is used for each signal phase in the analysis.

4.2 Capacity Estimation along Sections of Highway

The capacity of highway sections -- as distinct from approaches to intersections -- is a function of roadway geometrics, traffic composition (e.g. percent heavy trucks and buses in the traffic stream) and, of course, motorist behavior. There is a fundamental relationship which relates service volume (i.e. the number of vehicles serviced within a uniform highway section in a given time period) to traffic density. The top curve in Figure 4-1 illustrates this relationship.

As indicated, there are two flow regimes: (1) Free Flow (left side of curve); and (2) Forced Flow (right side). In the Free Flow regime, the traffic demand is fully serviced; the service volume increases as demand volume and density increase, until the service volume attains its maximum value, which is the capacity of the highway section. As traffic demand and the resulting highway density increase beyond this "critical" value, the rate at which traffic can be serviced (i.e. the service volume) can actually decline below capacity ("capacity drop"). Therefore, in order to realistically represent traffic performance during congested conditions (i.e. when demand exceeds capacity), it is necessary to estimate the service volume, V_F, under congested conditions.

The value of V_F can be expressed as:

$$V_F = R \times Capacity$$

where:

R = Reduction factor which is less than unity

We have employed a value of R=0.90. The advisability of such a capacity reduction factor is based upon empirical studies that identified a fall-off in the service flow rate when congestion occurs at “bottlenecks” or “choke points” on a freeway system. Zhang and Levinson[3] describe a research program that collected data from a computer-based surveillance system (loop detectors) installed on the Interstate Highway System, at 27 active bottlenecks in the twin cities metro area in Minnesota over a 7-week period. When flow breakdown occurs, queues are formed which discharge at lower flow rates than the maximum capacity prior to observed breakdown. These queue discharge flow (QDF) rates vary from one location to the next and also vary by day of week and time of day based upon local circumstances. The cited reference presents a mean QDF of 2,016 passenger cars per hour per lane (pcphpl). This figure compares with the nominal capacity estimate of 2,250 pcphpl estimated for the ETE and indicated in Appendix K for freeway links. The ratio of these two numbers is 0.896 which translates into a capacity reduction factor of 0.90.

Since the principal objective of evacuation time estimate analyses is to develop a “realistic” estimate of evacuation times, use of the representative value for this capacity reduction factor (R=0.90) is justified. This factor is applied only when flow breaks down, as determined by the simulation model.

Rural roads, like freeways, are classified as “uninterrupted flow” facilities. (This is in contrast with urban street systems which have closely spaced signalized intersections and are classified as “interrupted flow” facilities.) As such, traffic flow along rural roads is subject to the same effects as freeways in the event traffic demand exceeds the nominal capacity, resulting in queuing and lower QDF rates. As a practical matter, rural roads rarely break down at locations away from intersections. Any breakdowns on rural roads are generally experienced at intersections where other model logic applies, or at lane drops which reduce capacity there. Therefore, the application of a factor of 0.90 is appropriate on rural roads, but rarely, if ever, activated.

The estimated value of capacity is based primarily upon the type of facility and on roadway geometrics. Sections of roadway with adverse geometrics are characterized by lower free-flow speeds and lane capacity. Exhibit 15-30 in the Highway Capacity Manual was referenced to estimate saturation flow rates. The impact of narrow lanes and shoulders on free-flow speed and on capacity is not material, particularly when flow is predominantly in one direction as is the case during an evacuation.

The procedure used here was to estimate "section" capacity, V_E, based on observations made traveling over each section of the evacuation network, based on the posted speed limits and travel behavior of other motorists and by reference to the 2010 HCM. The DYNEV II simulation model determines for each highway section, represented as a network link, whether its capacity would be limited by the "section-specific" service volume, V_E, or by the intersection-specific capacity. For each link, the model selects the lower value of capacity.

[3]Lei Zhang and David Levinson, “Some Properties of Flows at Freeway Bottlenecks,” Transportation Research Record 1883, 2004.

4.3 Application to the North Anna Power Station Study Area

As part of the development of the link-node analysis network for the study area, an estimate of roadway capacity is required. The source material for the capacity estimates presented herein is contained in:

2010 Highway Capacity Manual (HCM)
Transportation Research Board
National Research Council
Washington, D.C.

The highway system in the study area consists primarily of three categories of roads and, of course, intersections:

- Two-Lane roads: Local, State
- Multi-Lane Highways (at-grade)
- Freeways

Each of these classifications will be discussed.

4.3.1 Two-Lane Roads

Ref: HCM Chapter 15

Two lane roads comprise the majority of highways within the EPZ. The per-lane capacity of a two-lane highway is estimated at 1,700 passenger cars per hour (pc/h). This estimate is essentially independent of the directional distribution of traffic volume except that, for extended distances, the two-way capacity will not exceed 3200 pc/h. The HCM procedures then estimate Level of Service (LOS) and Average Travel Speed. The DYNEV II simulation model accepts the specified value of capacity as input and computes average speed based on the time-varying demand: capacity relations.

Based on the field survey and on expected traffic operations associated with evacuation scenarios:

- Most sections of two-lane roads within the EPZ are classified as “Class I”, with "level terrain"; some are “rolling terrain”.
- “Class II” highways are mostly those within urban and suburban centers.

4.3.2 Multi-Lane Highway

Ref: HCM Chapter 14

Exhibit 14-2 of the HCM 2010 presents a set of curves that indicate a per-lane capacity ranging from approximately 1900 to 2200 pc/h, for free-speeds of 45 to 60 mph, respectively. Based on observation, the multi-lane highways outside of urban areas within the EPZ service traffic with free-speeds in this range. The actual time-varying speeds computed by the simulation model reflect the demand: capacity relationship and the impact of control at intersections. A conservative estimate of per-lane capacity of 1900 pc/h is adopted for this study for multi-lane highways outside of urban areas, as shown in Appendix K.

4.3.3 Freeways

Ref: HCM Chapters 10, 11, 12, 13

Chapter 10 of the HCM 2010 describes a procedure for integrating the results obtained in Chapters 11, 12 and 13, which compute capacity and LOS for freeway components. Chapter 10 also presents a discussion of simulation models. The DYNEV II simulation model automatically performs this integration process.

Chapter 11 of the HCM 2010 presents procedures for estimating capacity and LOS for “Basic Freeway Segments". Exhibit 11-17 of the HCM 2010 presents capacity vs. free speed estimates, which are provided below.

Free Speed (mph):	55	60	65	70+
Per-Lane Capacity (pc/h):	2250	2300	2350	2400

The inputs to the simulation model are highway geometrics, free-speeds and capacity based on field observations. The simulation logic calculates actual time-varying speeds based on demand: capacity relationships. A conservative estimate of per-lane capacity of 2250 pc/h is adopted for this study for freeways, as shown in Appendix K.

Chapter 12 of the HCM 2010 presents procedures for estimating capacity, speed, density and LOS for freeway weaving sections. The simulation model contains logic that relates speed to demand volume: capacity ratio. The value of capacity obtained from the computational procedures detailed in Chapter 12 depends on the "Type" and geometrics of the weaving segment and on the "Volume Ratio" (ratio of weaving volume to total volume).

Chapter 13 of the HCM 2010 presents procedures for estimating capacities of ramps and of "merge" areas. There are three significant factors to the determination of capacity of a ramp-freeway junction: The capacity of the freeway immediately downstream of an on-ramp or immediately upstream of an off-ramp; the capacity of the ramp roadway; and the maximum flow rate entering the ramp influence area. In most cases, the freeway capacity is the controlling factor. Values of this merge area capacity are presented in Exhibit 13-8 of the HCM 2010, and depend on the number of freeway lanes and on the freeway free speed. Ramp capacity is presented in Exhibit 13-10 and is a function of the ramp free flow speed. The DYNEV II simulation model logic simulates the merging operations of the ramp and freeway traffic in accord with the procedures in Chapter 13 of the HCM 2010. If congestion results from an excess of demand relative to capacity, then the model allocates service appropriately to the two entering traffic streams and produces LOS F conditions (The HCM does not address LOS F explicitly).

4.3.4 Intersections

Ref: HCM Chapters 18, 19, 20, 21

Procedures for estimating capacity and LOS for approaches to intersections are presented in Chapter 18 (signalized intersections), Chapters 19, 20 (un-signalized intersections) and Chapter 21 (roundabouts). The complexity of these computations is indicated by the aggregate length of these chapters. The DYNEV II simulation logic is likewise complex.

The simulation model explicitly models intersections: Stop/yield controlled intersections (both 2-way and all-way) and traffic signal controlled intersections. Where intersections are controlled by fixed time controllers, traffic signal timings are set to reflect average (non-evacuation) traffic conditions. Actuated traffic signal settings respond to the time-varying demands of evacuation traffic to adjust the relative capacities of the competing intersection approaches.

The model is also capable of modeling the presence of manned traffic control. At specific locations where it is advisable or where existing plans call for overriding existing traffic control to implement manned control, the model will use actuated signal timings that reflect the presence of traffic guides. At locations where a special traffic control strategy (continuous left-turns, contra-flow lanes) is used, the strategy is modeled explicitly. Where applicable, the location and type of traffic control for nodes in the evacuation network are noted in Appendix K. The characteristics of the ten highest volume signalized intersections are detailed in Appendix J.

4.4 Simulation and Capacity Estimation

Chapter 6 of the HCM is entitled, "HCM and Alternative Analysis Tools." The chapter discusses the use of alternative tools such as simulation modeling to evaluate the operational performance of highway networks. Among the reasons cited in Chapter 6 to consider using simulation as an alternative analysis tool is:

> *"The system under study involves a group of different facilities or travel modes with mutual interactions invoking several procedural chapters of the HCM. Alternative tools are able to analyze these facilities as a single system."*

This statement succinctly describes the analyses required to determine traffic operations across an area encompassing an EPZ operating under evacuation conditions. The model utilized for this study, DYNEV II, is further described in Appendix C. It is essential to recognize that simulation models do not replicate the methodology and procedures of the HCM – they *replace* these procedures by describing the complex interactions of traffic flow and computing Measures of Effectiveness (MOE) detailing the operational performance of traffic over time and by location. The DYNEV II simulation model includes some HCM 2010 procedures only for the purpose of estimating capacity.

All simulation models must be calibrated properly with field observations that quantify the performance parameters applicable to the analysis network. Two of the most important of these are: (1) Free flow speed (FFS); and (2) saturation headway, h_{sat}. The first of these is estimated by direct observation during the road survey; the second is estimated using the concepts of the HCM 2010, as described earlier. These parameters are listed in Appendix K, for each network link.

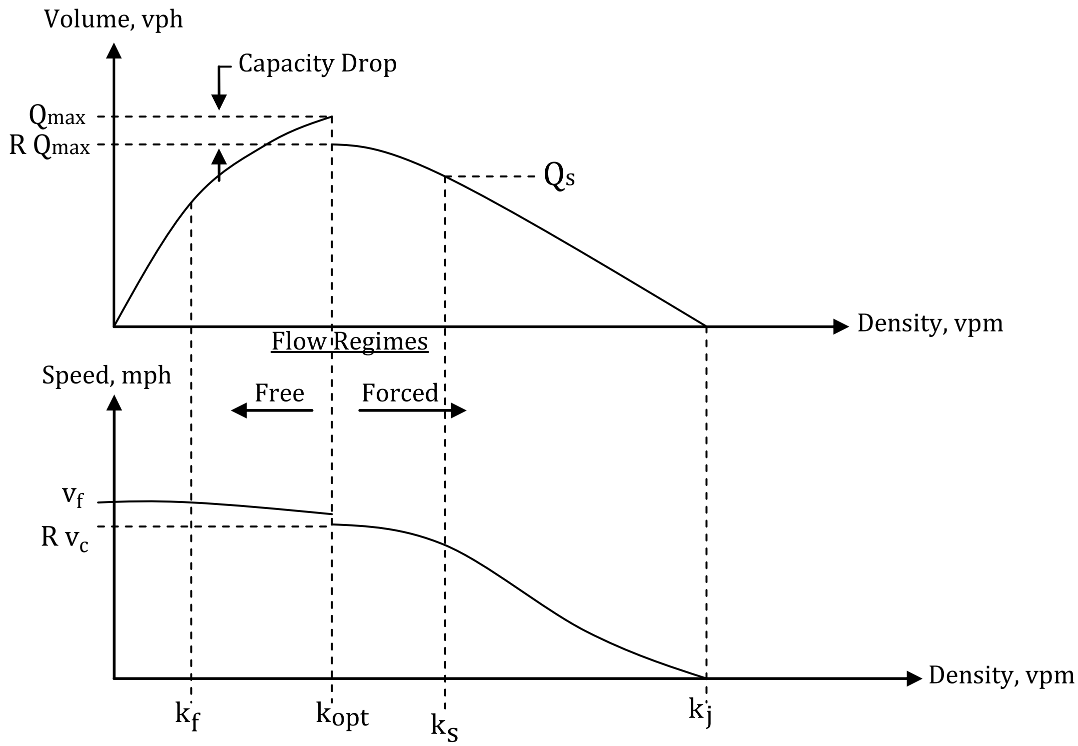


Figure 4-1. Fundamental Diagrams

5 ESTIMATION OF TRIP GENERATION TIME

Federal Government guidelines (see NUREG CR-7002) specify that the planner estimate the distributions of elapsed times associated with mobilization activities undertaken by the public to prepare for the evacuation trip. The elapsed time associated with each activity is represented as a statistical distribution reflecting differences between members of the public. The quantification of these activity-based distributions relies largely on the results of the telephone survey. We define the sum of these distributions of elapsed times as the Trip Generation Time Distribution.

5.1 Background

In general, an accident at a nuclear power plant is characterized by the following Emergency Classification Levels (see Appendix 1 of NUREG 0654 for details):

1. Unusual Event
2. Alert
3. Site Area Emergency
4. General Emergency

At each level, the Federal guidelines specify a set of Actions to be undertaken by the Licensee, and by State and Local offsite authorities. As a Planning Basis, we will adopt a conservative posture, in accordance with Section 1.2 of NUREG/CR-7002, that a rapidly escalating accident will be considered in calculating the Trip Generation Time. We will assume:

1. The Advisory to Evacuate will be announced coincident with the siren notification.
2. Mobilization of the general population will commence within 15 minutes after the siren notification.
3. ETE are measured relative to the Advisory to Evacuate.

We emphasize that the adoption of this planning basis is not a representation that these events will occur within the indicated time frame. Rather, these assumptions are necessary in order to:

1. Establish a temporal framework for estimating the Trip Generation distribution in the format recommended in Section 2.13 of NUREG/CR-6863.
2. Identify temporal points of reference that uniquely define "Clear Time" and ETE.

It is likely that a longer time will elapse between the various classes of an emergency.

For example, suppose one hour elapses from the siren alert to the Advisory to Evacuate. In this case, it is reasonable to expect some degree of spontaneous evacuation by the public during this one-hour period. As a result, the population within the EPZ will be lower when the Advisory to Evacuate is announced, than at the time of the siren alert. In addition, many will engage in preparation activities to evacuate, in anticipation that an Advisory will be broadcast. Thus, the time needed to complete the mobilization activities and the number of people remaining to evacuate the EPZ after the Advisory to Evacuate, will both be somewhat less than the estimates presented in this report. Consequently, the ETE presented in this report are higher than the actual evacuation time, if this hypothetical situation were to take place.

The notification process consists of two events:

1. Transmitting information using the alert notification systems available within the EPZ (e.g. sirens, tone alerts, EAS broadcasts, loud speakers).
2. Receiving and correctly interpreting the information that is transmitted.

The population within the EPZ is dispersed over an area of 384 square miles and is engaged in a wide variety of activities. It must be anticipated that some time will elapse between the transmission and receipt of the information advising the public of an accident.

The amount of elapsed time will vary from one individual to the next depending on where that person is, what that person is doing, and related factors. Furthermore, some persons who will be directly involved with the evacuation process may be outside the EPZ at the time the emergency is declared. These people may be commuters, shoppers and other travelers who reside within the EPZ and who will return to join the other household members upon receiving notification of an emergency.

As indicated in Section 2.13 of NUREG/CR-6863, the estimated elapsed times for the receipt of notification can be expressed as a distribution reflecting the different notification times for different people within, and outside, the EPZ. By using time distributions, it is also possible to distinguish between different population groups and different day-of-week and time-of-day scenarios, so that accurate ETE may be computed.

For example, people at home or at work within the EPZ will be notified by siren, and/or tone alert and/or radio (if available). Those well outside the EPZ will be notified by telephone, radio, TV and word-of-mouth, with potentially longer time lags. Furthermore, the spatial distribution of the EPZ population will differ with time of day - families will be united in the evenings, but dispersed during the day. In this respect, weekends will differ from weekdays.

As indicated in Section 4.1 of NUREG/CR-7002, the information required to compute trip generation times is typically obtained from a telephone survey of EPZ residents. Such a survey was conducted in support of this ETE study. Appendix F presents the survey sampling plan, survey instrument, and raw survey results. It is important to note that the shape and duration of the evacuation trip mobilization distribution is important at sites where traffic congestion is not expected to cause the evacuation time estimate to extend in time well beyond the trip generation period. The remaining discussion will focus on the application of the trip generation data obtained from the telephone survey to the development of the ETE documented in this report.

5.2 Fundamental Considerations

The environment leading up to the time that people begin their evacuation trips consists of a sequence of events and activities. Each event (other than the first) occurs at an instant in time and is the outcome of an activity.

Activities are undertaken over a period of time. Activities may be in "series" (i.e. to undertake an activity implies the completion of all preceding events) or may be in parallel (two or more activities may take place over the same period of time). Activities conducted in series are functionally dependent on the completion of prior activities; activities conducted in parallel are functionally independent of one another. The relevant events associated with the public's preparation for evacuation are:

Event Number	Event Description
1	Notification
2	Awareness of Situation
3	Depart Work
4	Arrive Home
5	Depart on Evacuation Trip

Associated with each sequence of events are one or more activities, as outlined below:

Table 5-1. Event Sequence for Evacuation Activities

Event Sequence	Activity	Distribution
1 → 2	Receive Notification	1
2 → 3	Prepare to Leave Work	2
2,3 → 4	Travel Home	3
2,4 → 5	Prepare to Leave to Evacuate	4
N/A	Snow Clearance	5

These relationships are shown graphically in Figure 5-1.

- An Event is a 'state' that exists at a point in time (e.g., depart work, arrive home)
- An Activity is a 'process' that takes place over some elapsed time (e.g., prepare to leave work, travel home)

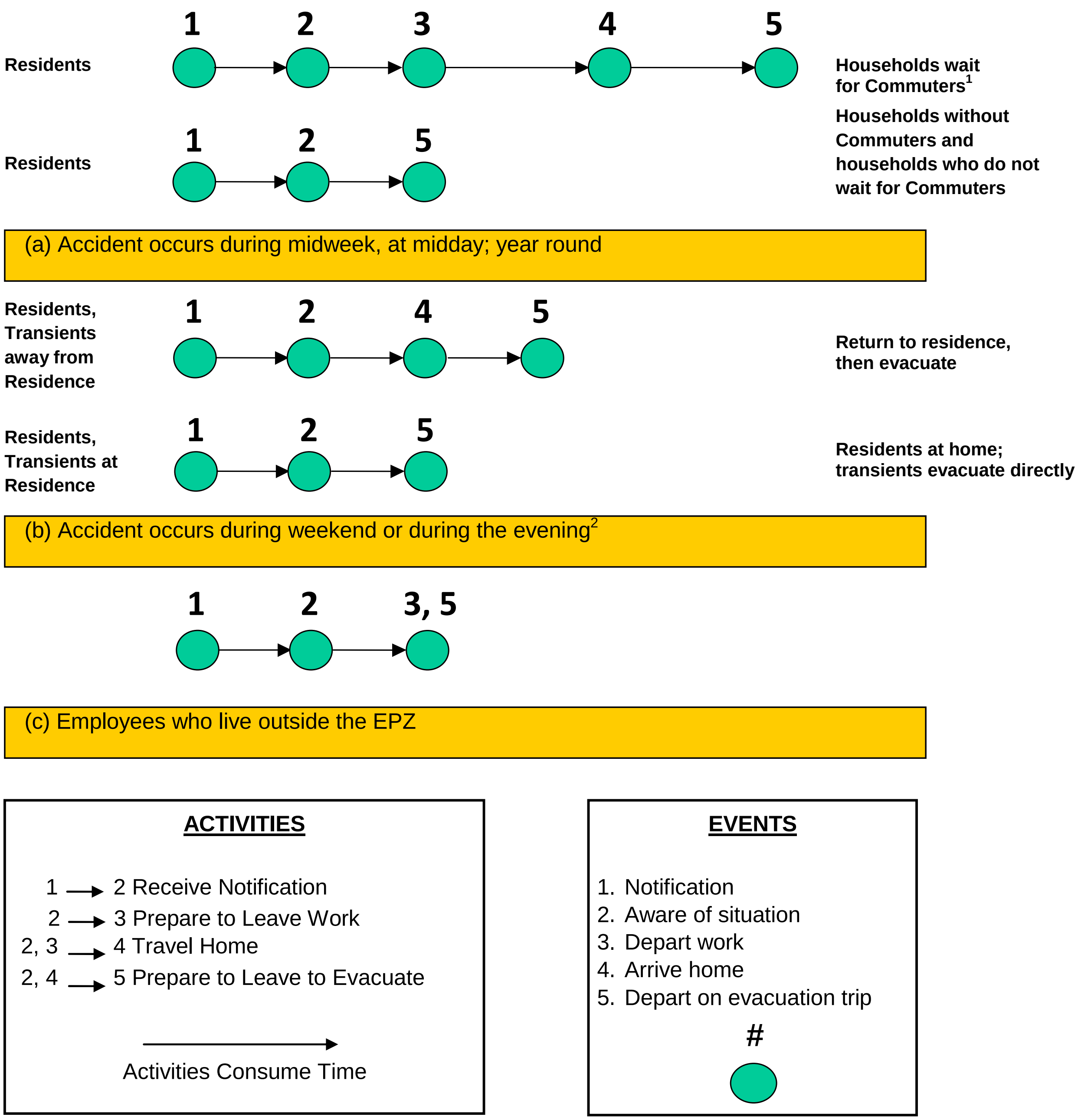
As such, a completed Activity changes the 'state' of an individual (e.g. the activity, 'travel home' changes the state from 'depart work' to 'arrive home'). Therefore, an Activity can be described as an 'Event Sequence'; the elapsed times to perform an event sequence vary from one person to the next and are described as statistical distributions on the following pages.

An employee who lives outside the EPZ will follow sequence (c) of Figure 5-1. A household within the EPZ that has one or more commuters at work, and will await their return before beginning the evacuation trip will follow the first sequence of Figure 5-1(a). A household within the EPZ that has no commuters at work, or that will not await the return of any commuters, will follow the second sequence of Figure 5-1(a), regardless of day of week or time of day.

Households with no commuters on weekends or in the evening/night-time, will follow the applicable sequence in Figure 5-1(b). Transients will always follow one of the sequences of Figure 5-1(b). Some transients away from their residence could elect to evacuate immediately without returning to the residence, as indicated in the second sequence.

It is seen from Figure 5-1, that the Trip Generation time (i.e. the total elapsed time from Event 1 to Event 5) depends on the scenario and will vary from one household to the next. Furthermore, Event 5 depends, in a complicated way, on the time distributions of all activities preceding that event. That is, to estimate the time distribution of Event 5, we must obtain estimates of the time distributions of all preceding events. For this study, we adopt the conservative posture that all activities will occur in sequence.

In some cases, assuming certain events occur strictly sequential (for instance, commuter returning home before beginning preparation to leave, or removing snow only after the preparation to leave) can result in rather *conservative* (that is, longer) estimates of mobilization times. It is reasonable to expect that at least some parts of these events will overlap for many households, but that assumption is not made in this study.



[1] Applies for evening and weekends also if commuters are at work.
[2] Applies throughout the year for transients.

Figure 5-1. Events and Activities Preceding the Evacuation Trip

5.3 Estimated Time Distributions of Activities Preceding Event 5

The time distribution of an event is obtained by "summing" the time distributions of all prior contributing activities. (This "summing" process is quite different than an algebraic sum since it is performed on distributions – not scalar numbers).

Time Distribution No. 1, Notification Process: Activity 1 $\rightarrow$ 2

In accordance with the 2012 Federal Emergency Management Agency (FEMA) Radiological Emergency Preparedness Program Manual, 100% of the population is notified within 45 minutes. It is assumed (based on the presence of sirens within the EPZ) that 87 percent of those within the EPZ will be aware of the accident within 30 minutes with the remainder notified within the following 15 minutes. The notification distribution is given below:

Table 5-2. Time Distribution for Notifying the Public

Elapsed Time (Minutes)	Percent of Population Notified
0	0%
5	7%
10	13%
15	27%
20	47%
25	66%
30	87%
35	92%
40	97%
45	100%

Distribution No. 2, Prepare to Leave Work: Activity 2 $\rightarrow$ 3

It is reasonable to expect that the vast majority of business enterprises within the EPZ will elect to shut down following notification and most employees would leave work quickly. Commuters, who work outside the EPZ could, in all probability, also leave quickly since facilities outside the EPZ would remain open and other personnel would remain. Personnel or farmers responsible for equipment/livestock would require additional time to secure their facility. The distribution of Activity 2 → 3 shown in Table 5-3 reflects data obtained by the telephone survey. This distribution is plotted in Figure 5-2.

Table 5-3. Time Distribution for Employees to Prepare to Leave Work

Elapsed Time (Minutes)	Cumulative Percent Employees Leaving Work	Elapsed Time (Minutes)	Cumulative Percent Employees Leaving Work
0	0%	45	86%
5	29%	50	86%
10	39%	55	87%
15	50%	60	93%
20	57%	75	97%
25	61%	90	98%
30	76%	105	99%
35	77%	120	100%
40	78%	-	-

NOTE: The survey data was normalized to distribute the "Don't know" response. That is, the sample was reduced in size to include only those households who responded to this question. The underlying assumption is that the distribution of this activity for the “Don’t know” responders, if the event takes place, would be the same as those responders who provided estimates.

Distribution No. 3, Travel Home: Activity 3 $\rightarrow$ 4

These data are provided directly by those households which responded to the telephone survey. This distribution is plotted in Figure 5-2 and listed in Table 5-4.

Table 5-4. Time Distribution for Commuters to Travel Home

Elapsed Time (Minutes)	Cumulative Percent Returning Home	Elapsed Time (Minutes)	Cumulative Percent Returning Home
0	0%	45	79%
5	4%	50	81%
10	10%	55	81%
15	22%	60	89%
20	34%	75	94%
25	39%	90	97%
30	54%	105	99%
35	58%	120	100%
40	64%	-	-

NOTE: The survey data was normalized to distribute the "Don't know" response

Distribution No. 4, Prepare to Leave Home: Activity 2, 4 $\rightarrow$ 5

These data are provided directly by those households which responded to the telephone survey. This distribution is plotted in Figure 5-2 and listed in Table 5-5.

Table 5-5. Time Distribution for Population to Prepare to Evacuate

Elapsed Time (Minutes)	Cumulative Percent Ready to Evacuate
0	0%
15	31%
30	60%
45	68%
60	80%
75	91%
90	92%
105	93%
120	96%
135	98%
150	98%
165	98%
180	99%
195	100%

NOTE: The survey data was normalized to distribute the "Don't know" response

Distribution No. 5, Snow Clearance Time Distribution

Inclement weather scenarios involving snowfall must address the time lags associated with snow clearance. It is assumed that snow equipment is mobilized and deployed during the snowfall to maintain passable roads. The general consensus is that the snow-plowing efforts are generally successful for all but the most extreme blizzards when the rate of snow accumulation exceeds that of snow clearance over a period of many hours.

Consequently, it is reasonable to assume that the highway system will remain passable – albeit at a lower capacity – under the vast majority of snow conditions. Nevertheless, for the vehicles to gain access to the highway system, it may be necessary for driveways and employee parking lots to be cleared to the extent needed to permit vehicles to gain access to the roadways. These clearance activities take time; this time must be incorporated into the trip generation time distributions. These data are provided by those households which responded to the Surry 2012 telephone survey. This distribution is plotted in Figure 5-2 and listed in Table 5-6.

Note that those respondents (33%) who answered that they would not take time to clear their driveway were assumed to be ready immediately at the start of this activity. Essentially they would drive through the snow on the driveway to access the roadway and begin their evacuation trip.

Table 5-6. Time Distribution for Population to Clear 6"-8" of Snow

Elapsed Time (Minutes)	Cumulative Percent Completing Snow Removal
0	33%
15	42%
30	69%
45	73%
60	84%
75	91%
90	92%
105	92%
120	95%
135	97%
150	97%
165	97%
180	100%

NOTE: The survey data was normalized to distribute the "Don't know" response

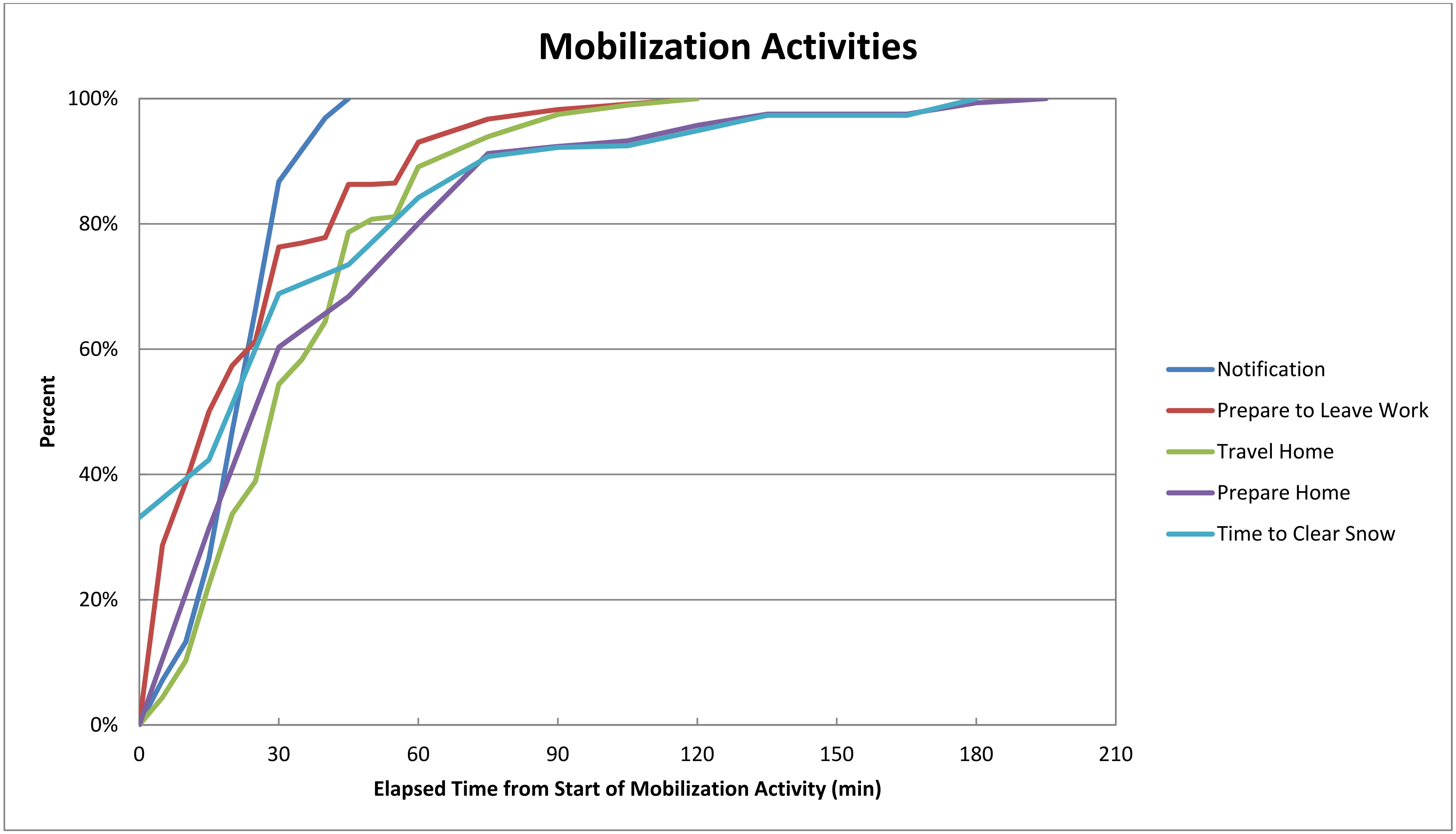


Figure 5-2. Evacuation Mobilization Activities

5.4 Calculation of Trip Generation Time Distribution

The time distributions for each of the mobilization activities presented herein must be combined to form the appropriate Trip Generation Distributions. As discussed above, this study assumes that the stated events take place in sequence such that all preceding events must be completed before the current event can occur. For example, if a household awaits the return of a commuter, the work-to-home trip (Activity 3 $\rightarrow$ 4) must precede Activity 4 $\rightarrow$ 5.

To calculate the time distribution of an event that is dependent on two sequential activities, it is necessary to "sum" the distributions associated with these prior activities. The distribution summing algorithm is applied repeatedly as shown to form the required distribution. As an outcome of this procedure, new time distributions are formed; we assign "letter" designations to these intermediate distributions to describe the procedure. Table 5-7 presents the summing procedure to arrive at each designated distribution.

Table 5-7. Mapping Distributions to Events

Apply "Summing" Algorithm To:	Distribution Obtained	Event Defined
Distributions 1 and 2	Distribution A	Event 3
Distributions A and 3	Distribution B	Event 4
Distributions B and 4	Distribution C	Event 5
Distributions 1 and 4	Distribution D	Event 5
Distributions C and 5	Distribution E	Event 5
Distributions D and 5	Distribution F	Event 5

Table 5-8 presents a description of each of the final trip generation distributions achieved after the summing process is completed.

Table 5-8. Description of the Distributions

Distribution	Description
A	Time distribution of commuters departing place of work (Event 3). Also applies to employees who work within the EPZ who live outside, and to Transients within the EPZ.
B	Time distribution of commuters arriving home (Event 4).
C	Time distribution of residents with commuters who return home, leaving home to begin the evacuation trip (Event 5).
D	Time distribution of residents without commuters returning home, leaving home to begin the evacuation trip (Event 5).
E	Time distribution of residents with commuters who return home, leaving home to begin the evacuation trip, after snow clearance activities (Event 5).
F	Time distribution of residents with no commuters returning home, leaving to begin the evacuation trip, after snow clearance activities (Event 5).

5.4.1 Statistical Outliers

As already mentioned, some portion of the survey respondents answer "don't know" to some questions or choose to not respond to a question. The mobilization activity distributions are based upon actual responses. But, it is the nature of surveys that a few numeric responses are inconsistent with the overall pattern of results. An example would be a case in which for 500 responses, almost all of them estimate less than two hours for a given answer, but 3 say "four hours" and 4 say "six or more hours".

These "outliers" must be considered: are they valid responses, or so atypical that they should be dropped from the sample?

In assessing outliers, there are three alternates to consider:

1) Some responses with very long times may be valid, but reflect the reality that the respondent really needs to be classified in a different population subgroup, based upon special needs;

2) Other responses may be unrealistic (6 hours to return home from commuting distance, or 2 days to prepare the home for departure);

3) Some high values are representative and plausible, and one must not cut them as part of the consideration of outliers.

The issue of course is how to make the decision that a given response or set of responses are to be considered "outliers" for the component mobilization activities, using a method that objectively quantifies the process.

There is considerable statistical literature on the identification and treatment of outliers singly or in groups, much of which assumes the data is normally distributed and some of which uses non-parametric methods to avoid that assumption. The literature cites that limited work has been done directly on outliers in sample survey responses.

In establishing the overall mobilization time/trip generation distributions, the following principles are used:

1) It is recognized that the overall trip generation distributions are conservative estimates, because they assume a household will do the mobilization activities sequentially, with no overlap of activities;

2) The individual mobilization activities (prepare to leave work, travel home, prepare home, clear snow) are reviewed for outliers, and then the overall trip generation distributions are created (see Figure 5-1, Table 5-7, Table 5-8);

3) Outliers can be eliminated either because the response reflects a special population (e.g. special needs, transit dependent) or lack of realism, because the purpose is to estimate trip generation patterns for personal vehicles;

4) To eliminate outliers,
    a) the mean and standard deviation of the specific activity are estimated from the responses,
    b) the median of the same data is estimated, with its position relative to the mean noted,
    c) the histogram of the data is inspected, and
    d) all values greater than 3.5 standard deviations are flagged for attention, taking special note of whether there are gaps (categories with zero entries) in the histogram display.

    In general, only flagged values more than 4 standard deviations from the mean are allowed to be considered outliers, with gaps in the histogram expected.

    When flagged values are classified as outliers and dropped, steps “a” to “d” are repeated.

5) As a practical matter, even with outliers eliminated by the above, the resultant histogram, viewed as a cumulative distribution, is not a normal distribution. A typical situation that results is shown below in Figure 5-3.

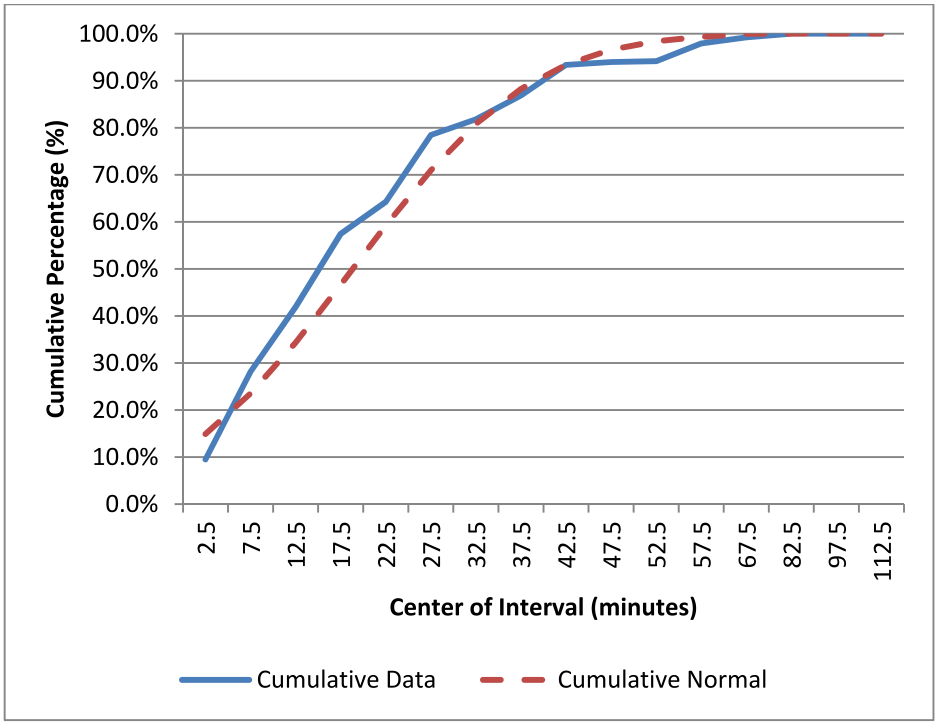


Figure 5-3. Comparison of Data Distribution and Normal Distribution

6) In particular, the cumulative distribution differs from the normal distribution in two key aspects, both very important in loading a network to estimate evacuation times:

- Most of the real data is to the left of the "normal" curve above, indicating that the network loads faster for the first 80-85% of the vehicles, potentially causing more (and earlier) congestion than otherwise modeled;
- The last 10-15% of the real data "tails off" slower than the comparable "normal" curve, indicating that there is significant traffic still loading at later times.

Because these two features are important to preserve, it is the histogram of the data that is used to describe the mobilization activities, not a "normal" curve fit to the data. One could consider other distributions, but using the shape of the *actual* data curve is unambiguous and preserves these important features;

7) With the mobilization activities each modeled according to Steps 1-6, including preserving the features cited in Step 6, the overall (or total) mobilization times are constructed.

This is done by using the data sets and distributions under different scenarios (e.g. commuter returning, no commuter returning, no snow or snow in each). In general, these are additive, using weighting based upon the probability distributions of each element; Figure 5-4 presents the combined trip generation distributions designated A, C, D, E and F. These distributions are presented on the same time scale. (As discussed earlier, the use of strictly additive activities is a conservative approach, because it makes all activities <u>sequential</u> – preparation for departure follows the return of the commuter; snow clearance follows the preparation for departure, and so forth. In practice, it is reasonable that some of these activities are done in parallel, at least to some extent – for instance, preparation to depart begins by a household member at home while the commuter is still on the road.)

The mobilization distributions that result are used in their tabular/graphical form as direct inputs to later computations that lead to the ETE.

The DYNEV II simulation model is designed to accept varying rates of vehicle trip generation for each origin centroid, expressed in the form of histograms. These histograms, which represent Distributions A, C, D, E and F, properly displaced with respect to one another, are tabulated in Table 5-9 (Distribution B, Arrive Home, omitted for clarity).

The final time period (15) is 600 minutes long. This time period is added to allow the analysis network to clear, in the event congestion persists beyond the trip generation period. Note that there are no trips generated during this final time period.

5.4.2 Staged Evacuation Trip Generation

As defined in NUREG/CR-7002, staged evacuation consists of the following:

1. PAZ comprising the 2 mile region are advised to evacuate immediately
2. PAZ comprising regions extending from 2 to 5 miles downwind are advised to shelter in-place while the 2 mile region is cleared
3. As vehicles evacuate the 2 mile region, sheltered people from 2 to 5 miles downwind continue preparation for evacuation
4. The population sheltering in the 2 to 5 mile region are advised to begin evacuating when approximately 90% of those originally within the 2 mile region evacuate across the 2 mile region boundary
5. Non-compliance with the shelter recommendation is the same as the shadow evacuation percentage of 20%

<u>Assumptions</u>

1. The population in the shadow region beyond the EPZ boundary, extending to approximately 15 miles radially from the plant, will react as they do for all non-staged evacuation scenarios. That is 20% of these households will elect to evacuate with no shelter delay.

2. The EPZ population in PAZ beyond 5 miles will react as does the population in the 2 to 5 mile region; that is they will first shelter, then evacuate after the 90th percentile ETE for the 2 mile region.
3. The transient population will not be expected to stage their evacuation because of the limited sheltering options available to people who may be at parks, on a beach, or at other venues. Also, notifying the transient population of a staged evacuation would prove difficult.
4. Employees will also be assumed to evacuate without first sheltering.

<u>Procedure</u>

1. Trip generation for population groups in the 2 mile region will be as computed based upon the results of the telephone survey and analysis.
2. Trip generation for the population subject to staged evacuation will be formulated as follows:
    a. Identify the 90th percentile evacuation time for the PAZ comprising the two mile region. This value, T_{Scen}^*, is obtained from simulation results. It will become the time at which the region being sheltered will be told to evacuate for each scenario.
    b. The resultant trip generation curves for staging are then formed as follows:
        i. The non-shelter trip generation curve is followed until a maximum of 20% of the total trips are generated (to account for shelter non-compliance).
        ii. No additional trips are generated until time T_{Scen}^*
        iii. Following time T_{Scen}^*, the balance of trips are generated:
            1. by stepping up and then following the non-shelter trip generation curve (if T_{Scen}^* is $\leq$ max trip generation time) or
            2. by stepping up to 100% (if T_{Scen}^* is > max trip generation time)
    c. Note: This procedure implies that there may be different staged trip generation distributions for different scenarios. NUREG/CR-7002 uses the statement "approximately 90th percentile" as the time to end staging and begin evacuating. The value of T_{Scen}^* is 2:30 for weekday non-snow scenarios and 3:15 for weekday snow scenarios. The value of T_{Scen}^* is 1:45 for weekend non-snow scenarios and 3:00 for weekend snow scenarios. The reason for the difference between weekday and weekend scenarios is that for midweek, midday cases, approximately 65% of the vehicles within the 2-mile region are those of employees and transients, whereas the percentage is lower for weekend and evening cases. These population groups mobilize faster than the general population and therefore the 90th percentile ETE will be lower for cases with a higher percentage of employees and transients.
3. Staged trip generation distributions are created for the following population groups:
    a. Residents with returning commuters
    b. Residents without returning commuters
    c. Residents with returning commuters and snow conditions

d. Residents without returning commuters and snow conditions

Figure 5-5 presents the staged trip generation distributions for both residents with and without returning commuters; the 90th percentile two-mile evacuation time is 150 minutes for weekday non-snow, 195 minutes for weekday snow, 105 minutes for weekend non-snow, and 180 minutes for weekend snow scenarios. At the 90th percentile evacuation time, 20% of the population (who normally would have completed their mobilization activities for an un-staged evacuation) advised to shelter has nevertheless departed the area. These people do not comply with the shelter advisory. Also included on the plot are the trip generation distributions for these groups as applied to the regions advised to evacuate immediately.

Since the 90th percentile evacuation time occurs before the end of the trip generation time, after the sheltered region is advised to evacuate, the shelter trip generation distribution rises to meet the balance of the non-staged trip generation distribution. Following time T_{Scen}^{*}, the balance of staged evacuation trips that are ready to depart are released within 15 minutes. After T_{Scen}^{*}+15, the remainder of evacuation trips are generated in accordance with the unstaged trip generation distribution.

Table 5-10 provides the trip generation histograms for staged evacuation, weekday scenarios and Table 5-11 provides the trip generation histograms for staged evacuation, weekend scenarios.

5.4.3 Trip Generation for Waterways and Recreational Areas

The Louisa County Radiological Emergency Response Plan states that the Sheriff's Office, assisted by Fire and Rescue, is responsible for implementing evacuations, including campgrounds, Lake Anna, and other areas. As stated in the Spotsylvania and Louisa County RERP, additional help is available as necessary, to assist in the warning of persons on Lake Anna, from the State Department of Game and Inland Fisheries.

As indicated in Table 5-2, this study assumes 100% notification in 45 minutes. Table 5-9 indicates that all transients will have mobilized within 2 hours and 30 minutes. It is assumed that this 2.5 hour timeframe is sufficient time for boaters, campers and other transients to return to their vehicles and begin their evacuation trip.

Table 5-9. Trip Generation Histograms for the EPZ Population for Unstaged Evacuation

Time Period	Duration (Min)	Percent of Total Trips Generated Within Indicated Time Period					
		Employees (Distribution A)	Transients (Distribution A)	Residents with Commuters (Distribution C)	Residents Without Commuters (Distribution D)	Residents With Commuters Snow (Distribution E)	Residents Without Commuters Snow (Distribution F)
1	15	5%	5%	0%	2%	0%	1%
2	30	53%	53%	2%	41%	1%	17%
3	30	29%	29%	14%	31%	6%	28%
4	15	7%	7%	13%	10%	7%	12%
5	15	3%	3%	13%	7%	9%	11%
6	15	2%	2%	14%	2%	11%	8%
7	30	1%	1%	20%	3%	21%	9%
8	15	0%	0%	7%	1%	9%	3%
9	15	0%	0%	5%	1%	7%	3%
10	15	0%	0%	4%	0%	7%	1%
11	15	0%	0%	2%	1%	5%	2%
12	60	0%	0%	5%	1%	11%	4%
13	60	0%	0%	1%	0%	5%	1%
14	60	0%	0%	0%	0%	1%	0%
15	600	0%	0%	0%	0%	0%	0%

NOTE:

- Shadow vehicles are loaded onto the analysis network (Figure 1-2) using Distributions C and E for good weather and snow, respectively.
- Special event vehicles are loaded using Distribution A.

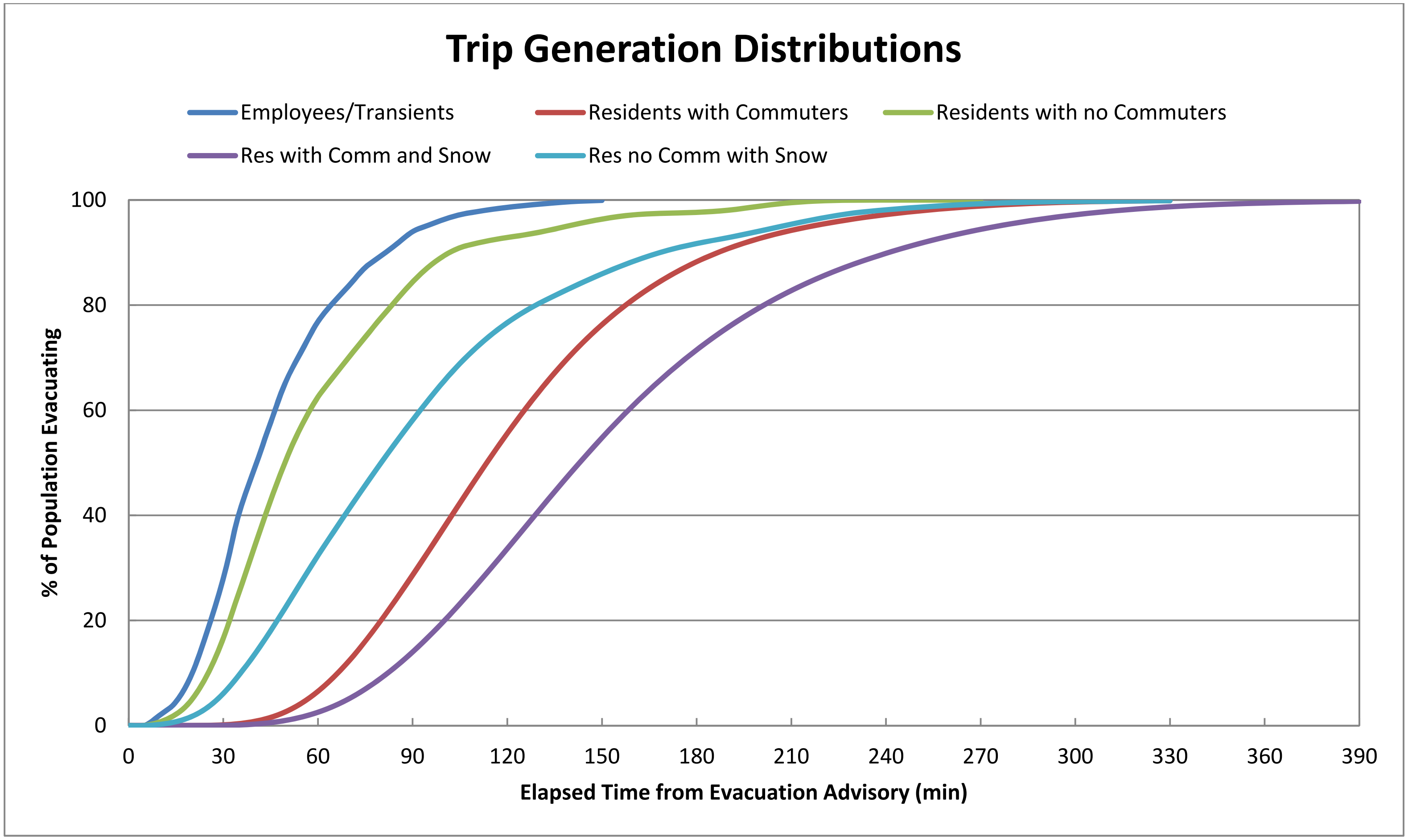


Figure 5-4. Comparison of Trip Generation Distributions

Table 5-10. Trip Generation Histograms for the EPZ Population for Staged Evacuation, Weekday

Time Period	Duration (Min)	Percent of Total Trips Generated Within Indicated Time Period*			
		Residents with Commuters Weekday (Distribution C)	Residents Without Commuters Weekday (Distribution D)	Residents With Commuters Weekday-Snow (Distribution E)	Residents Without Commuters Weekday-Snow (Distribution F)
1	15	0%	0%	0%	0%
2	30	0%	9%	0%	4%
3	30	3%	6%	1%	5%
4	15	3%	2%	2%	3%
5	15	2%	1%	2%	2%
6	15	3%	1%	2%	1%
7	30	4%	0%	4%	2%
8	15	68%	78%	2%	1%
9	15	5%	1%	1%	0%
10	15	4%	0%	2%	1%
11	15	2%	1%	67%	76%
12	60	5%	1%	11%	4%
13	60	1%	0%	5%	1%
14	60	0%	0%	1%	0%
15	600	0%	0%	0%	0%

*Trip Generation for Employees and Transients (see Table 5-9) is the same for Unstaged and Staged Evacuation.

Table 5-11. Trip Generation Histograms for the EPZ Population for Staged Evacuation, Weekend

Time Period	Duration (Min)	Percent of Total Trips Generated Within Indicated Time Period*			
		Residents with Commuters Weekend (Distribution C)	Residents Without Commuters Weekend (Distribution D)	Residents With Commuters Weekend-Snow (Distribution E)	Residents Without Commuters Weekend-Snow (Distribution F)
1	15	0%	0%	0%	0%
2	30	0%	9%	0%	4%
3	30	3%	6%	1%	5%
4	15	3%	2%	2%	3%
5	15	2%	1%	2%	2%
6	15	48%	75%	2%	1%
7	30	20%	3%	4%	2%
8	15	7%	1%	2%	1%
9	15	5%	1%	1%	0%
10	15	4%	0%	64%	75%
11	15	2%	1%	5%	2%
12	60	5%	1%	11%	4%
13	60	1%	0%	5%	1%
14	60	0%	0%	1%	0%
15	600	0%	0%	0%	0%

*Trip Generation for Employees and Transients (see Table 5-9) is the same for Unstaged and Staged Evacuation

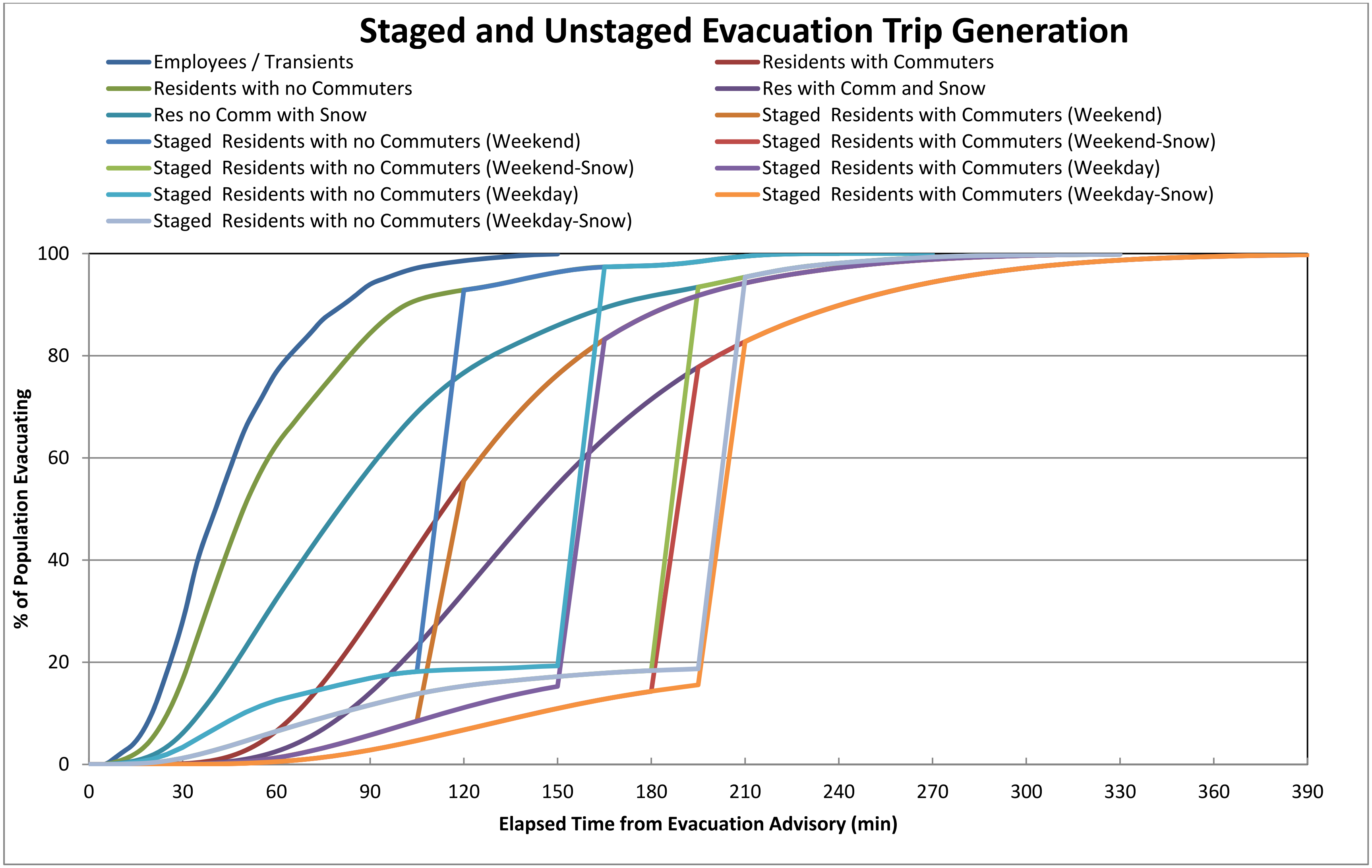


Figure 5-5. Comparison of Staged and Unstaged Trip Generation Distributions in the 2 to 5 Mile Region

6 DEMAND ESTIMATION FOR EVACUATION SCENARIOS

An evacuation "case" defines a combination of Evacuation Region and Evacuation Scenario. The definitions of "Region" and "Scenario" are as follows:

Region A grouping of contiguous evacuating PAZ that forms either a "keyhole" sector-based area, or a circular area within the EPZ, that must be evacuated in response to a radiological emergency.

Scenario A combination of circumstances, including time of day, day of week, season, and weather conditions. Scenarios define the number of people in each of the affected population groups and their respective mobilization time distributions.

A total of 41 Regions were defined which encompass all the groupings of PAZ considered. These Regions are defined in Table 6-1. The PAZ configurations are identified in Figure 6-1. Each keyhole sector-based area consists of a central circle centered at the power plant, and three adjoining sectors, each with a central angle of 22.5 degrees, as per NUREG/CR-7002 guidance. The central sector coincides with the wind direction. These sectors extend to 5 miles from the plant (Regions R04 through R15) or to the EPZ boundary (Regions R16 through R28). Regions R01, R02 and R03 represent evacuations of circular areas with radii of 2, 5 and 10 miles, respectively. Regions R29 through R41 are identical to Regions R02 and R04 through R15, respectively; however, those PAZ between 2 miles and 5 miles are staged until 90% of the 2-mile region (Region R01) has evacuated.

A total of 14 Scenarios were evaluated for all Regions. Thus, there are a total of 41 x 14 = 574 evacuation cases. Table 6-2 is a description of all Scenarios.

Each combination of region and scenario implies a specific population to be evacuated. Table 6-3 presents the percentage of each population group estimated to evacuate for each scenario. Table 6-4 presents the vehicle counts for each scenario for an evacuation of Region R03 – the entire EPZ.

The vehicle estimates presented in Section 3 are peak values. These peak values are adjusted depending on the scenario and region being considered, using scenario and region specific percentages, such that the average population is considered for each evacuation case. The scenario percentages are presented in Table 6-3, while the regional percentages are provided in Table H-1 and H-2. The percentages presented in Table 6-3 were determined as follows:

The number of residents with commuters during the week (when workforce is at its peak) is equal to the product of 59% (the number of households with at least one commuter) and 61% (the number of households with a commuter that would await the return of the commuter prior to evacuating). See assumption 3 in Section 2.3. It is estimated for weekend and evening scenarios that 10% of households with returning commuters will have a commuter at work during those times.

Employment is assumed to be at its peak during the winter, midweek, midday scenarios. Employment is reduced slightly (96%) for summer, midweek, midday scenarios. This is based on the estimation that 50% of the employees commuting into the EPZ will be on vacation for a week during the approximate 12 weeks of summer. It is further estimated that those taking vacation will be uniformly dispersed throughout the summer with approximately 4% of employees vacationing each week. It is further estimated that only 10% of the employees are working in the evenings and during the weekends.

Transient activity is estimated to be at its peak during summer weekends and less (69%) during the week. As shown in Appendix E, there is a moderate amount of lodging and campgrounds offering overnight accommodations in the EPZ; and an almost equal amount of parks and marinas where evening transient activity is very low; thus, transient activity is estimated to be – 56% during summer evening hours and 14% for winter evening hours. Transient activity on winter weekends is estimated to be 26%.

Seasonal population is estimated to be 100% during summer months and 0% during all other times.

As noted in the shadow footnote to Table 6-3, the shadow percentages are computed using a base of 20% (see assumption 5 in Section 2.2); to include the employees within the shadow region who may choose to evacuate, the voluntary evacuation is multiplied by a scenario-specific proportion of employees to permanent residents in the shadow region. For example, using the values provided in Table 6-4 for Scenario 1, the shadow percentage is computed as follows:

$$20\% \times \left(1 + \frac{727}{8{,}895 + 5{,}020}\right) = 21\%$$

One special event (Scenario 13) is considered for the ETE study – Kinetics Triathlon at Lake Anna State Park. Thus, the special event traffic is 100% evacuated for Scenario 13, and 0% for all other scenarios. This special event includes an additional 249 vehicles being loaded at the State Park, as shown in the Special Events column in Table 6-4.

It is estimated that summer school enrollment is approximately 10% of enrollment during the regular school year for summer, midweek, midday scenarios. School is not in session during weekends and evenings, thus no buses for schoolchildren are needed under those circumstances. As discussed in Section 7, schools are in session during the winter season, midweek, midday and 100% of buses will be needed under those circumstances. Transit buses for the transit-dependent population are set to 100% for all scenarios as it is assumed that the transit-dependent population is present in the EPZ for all scenarios.

External traffic is estimated to be reduced by 60% during evening scenarios and is 100% for all other scenarios.

Table 6-1. Description of Evacuation Regions

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																							
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R01	2-Mile Radius	2- Mile Radius					x		x	x	x																
R02	5-Mile Radius	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R03	Full EPZ	Full EPZ	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Evacuate 2-Mile Radius and Downwind to 5 Miles																											
Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																							
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R04	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R05	NE	34° - 56°					x		x	x	x	x	x	x													
R06	ENE, E	57° - 101°					x		x	x	x	x	x														
R07	ESE	102° - 123°					x		x	x	x	x														x	
R08	SE	124° - 146°					x	x	x	x	x	x														x	
R09	SSE, S	147° - 191°					x	x	x	x	x															x	
R10	SSW	192° - 213°					x	x	x	x	x																
R11	SW	214° - 236°			x		x	x	x	x	x																
R12	WSW	237° - 258°			x		x		x	x	x																
R13	W	259°- 281°			x		x		x	x	x					x											
R14	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R15	NNW	327° - 349°					x		x	x	x			x	x	x											
Evacuate 5-Mile Radius and Downwind to the EPZ Boundary																											
Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																							
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R16	N	349° - 11°			x		x	x	x	x	x	x	x	x	x	x			x	x	x					x	
R17	NNE	12° - 33°			x		x	x	x	x	x	x	x	x	x	x			x	x	x	x				x	
R18	NE	34° - 56°			x		x	x	x	x	x	x	x	x	x	x				x	x	x				x	
R19	ENE	57° - 78°			x		x	x	x	x	x	x	x	x	x	x					x	x	x			x	
R20	E	79° - 101°			x		x	x	x	x	x	x	x	x	x	x						x	x	x		x	
R21	ESE	102° - 123°			x		x	x	x	x	x	x	x	x	x	x						x	x	x	x	x	x
R22	SE	124° - 146°			x		x	x	x	x	x	x	x	x	x	x							x	x	x	x	x
R23	SSE, S	147° - 191°			x	x	x	x	x	x	x	x	x	x	x	x									x	x	x
R24	SSW	192° - 213°		x	x	x	x	x	x	x	x	x	x	x	x	x										x	x
R25	SW, WSW	214° - 258°	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x									x	

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																							
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R26	W	259° - 281°	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R27	WNW, NW	282° - 326°			x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R28	NNW	327° - 349°			x		x	x	x	x	x	x	x	x	x	x		x	x	x						x	
Staged Evacuation - 2-Mile Radius Evacuates, then Evacuate Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																							
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R29	-	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R30	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R31	NE	34° - 56°					x		x	x	x	x	x	x													
R32	ENE, E	57° - 101°					x		x	x	x	x	x														
R33	ESE	102° - 123°					x		x	x	x	x														x	
R34	SE	124° - 146°					x	x	x	x	x	x														x	
R35	SSE, S	147° - 191°					x	x	x	x	x															x	
R36	SSW	192° - 213°					x	x	x	x	x																
R37	SW	214° - 236°			x		x	x	x	x	x																
R38	WSW	237° - 258°			x		x		x	x	x																
R39	W	259°- 281°			x		x		x	x	x					x											
R40	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R41	NNW	327° - 349°					x		x	x	x			x	x	x											

Shelter-in-Place until 90% ETE for R01, then Evacuate

PAZ Shelter-in-Place

PAZ Evacuate

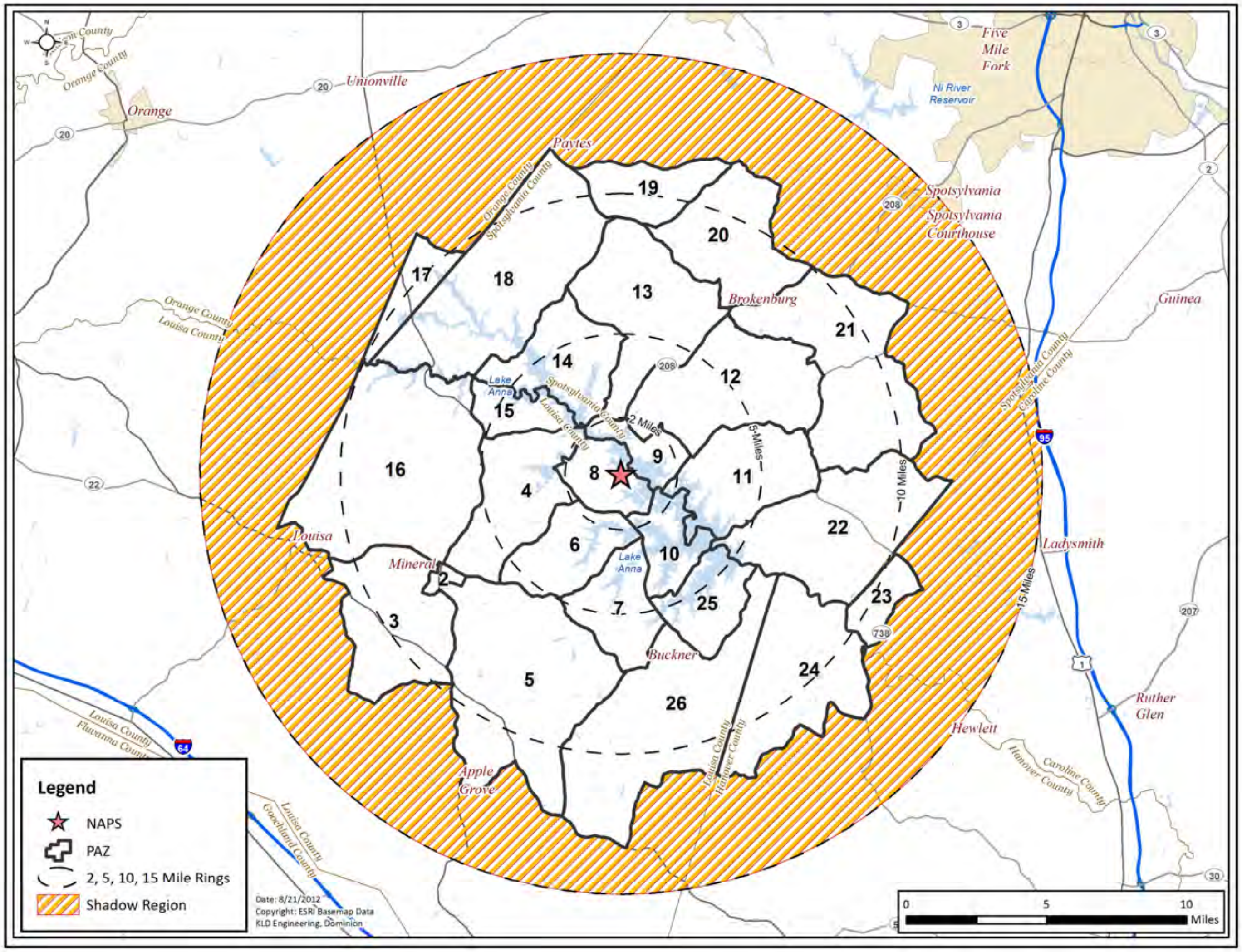


Figure 6-1. NAPS EPZ PAZ

Table 6-2. Evacuation Scenario Definitions

Scenario	Season[1]	Day of Week	Time of Day	Weather	Special
1	Summer	Midweek	Midday	Good	None
2	Summer	Midweek	Midday	Rain	None
3	Summer	Weekend	Midday	Good	None
4	Summer	Weekend	Midday	Rain	None
5	Summer	Midweek, Weekend	Evening	Good	None
6	Winter	Midweek	Midday	Good	None
7	Winter	Midweek	Midday	Rain	None
8	Winter	Midweek	Midday	Snow	None
9	Winter	Weekend	Midday	Good	None
10	Winter	Weekend	Midday	Rain	None
11	Winter	Weekend	Midday	Snow	None
12	Winter	Midweek, Weekend	Evening	Good	None
13	Winter	Weekend	Midday	Good	Kinetic Triathlon at Lake Anna State park
14	Summer	Midweek	Midday	Good	Roadway Impact – One Segment of US-522 NB will be Closed

[1] Winter means that school is in session (also applies to spring and autumn). Summer means that school is not in session.

Table 6-3. Percent of Population Groups Evacuating for Various Scenarios

Scenario	Households With Returning Commuters	Households Without Returning Commuters	Employees	Transients	Seasonal Transients	Shadow	Special Events	School Buses	Transit Buses	External Through Traffic
1	36%	64%	96%	69%	100%	21%	0%	10%	100%	100%
2	36%	64%	96%	69%	100%	21%	0%	10%	100%	100%
3	4%	96%	10%	100%	100%	20%	0%	0%	100%	100%
4	4%	96%	10%	100%	100%	20%	0%	0%	100%	100%
5	4%	96%	10%	56%	100%	20%	0%	0%	100%	40%
6	36%	64%	100%	15%	0%	21%	0%	100%	100%	100%
7	36%	64%	100%	15%	0%	21%	0%	100%	100%	100%
8	36%	64%	100%	15%	0%	21%	0%	100%	100%	100%
9	4%	96%	10%	26%	0%	20%	0%	0%	100%	100%
10	4%	96%	10%	26%	0%	20%	0%	0%	100%	100%
11	4%	96%	10%	26%	0%	20%	0%	0%	100%	100%
12	4%	96%	10%	14%	0%	20%	0%	0%	100%	40%
13	4%	96%	10%	26%	0%	20%	100%	0%	100%	100%
14	36%	64%	96%	69%	100%	21%	0%	10%	100%	100%

Resident Households with Commuters ....Households of EPZ residents who await the return of commuters prior to beginning the evacuation trip.
Resident Households with No Commuters ..Households of EPZ residents who do not have commuters or will not await the return of commuters prior to beginning the evacuation trip.
Employees..EPZ employees who live outside the EPZ
Transients ....People who are in the EPZ at the time of an accident for recreational or other (non-employment) purposes.
Shadow ....Residents and employees in the shadow region (outside of the EPZ) who will spontaneously decide to relocate during the evacuation. The basis for the values shown is a 20% relocation of shadow residents along with a proportional percentage of shadow employees.
Special Events ....Additional vehicles in the EPZ due to the identified special event.
School and Transit Buses ....Vehicle-equivalents present on the road during evacuation servicing schools and transit-dependent people (1 bus is equivalent to 2 passenger vehicles).
External Through Traffic ....Traffic on interstates/freeways and major arterial roads at the start of the evacuation. This traffic is stopped by access control approximately 2 hours after the evacuation begins.

Table 6-4. Vehicle Estimates by Scenario

Scenario	Households With Returning Commuters	Households Without Returning Commuters	Employees	Transients	Seasonal Transients	Shadow	Special Events	School Buses	Transit Buses	External Through Traffic	Total Scenario Vehicles
1	5,020	8,895	727	1,297	922	3,718	-	23	50	13,550	34,202
2	5,020	8,895	727	1,297	922	3,718	-	23	50	13,550	34,202
3	502	13,413	76	1,879	922	3,552	-	-	50	13,550	33,944
4	502	13,413	76	1,879	922	3,552	-	-	50	13,550	33,944
5	502	13,413	76	1,052	922	3,552	-	-	50	5,420	24,987
6	5,020	8,895	757	282	-	3,725	-	226	50	13,550	32,505
7	5,020	8,895	757	282	-	3,725	-	226	50	13,550	32,505
8	5,020	8,895	757	282	-	3,725	-	226	50	13,550	32,505
9	502	13,413	76	489	-	3,552	-	-	50	13,550	31,632
10	502	13,413	76	489	-	3,552	-	-	50	13,550	31,632
11	502	13,413	76	489	-	3,552	-	-	50	13,550	31,632
12	502	13,413	76	263	-	3,552	-	-	50	5,420	23,276
13	502	13,413	76	489	-	3,552	249	-	50	13,550	31,181
14	5,020	8,895	727	1,297	922	3,718	-	23	50	13,550	34,202

7 GENERAL POPULATION EVACUATION TIME ESTIMATES (ETE)

This section presents the ETE results of the computer analyses using the DYNEV II System described in Appendices B, C and D. These results cover 41 regions within the NAPS EPZ and the 14 Evacuation Scenarios discussed in Section 6.

The ETE for all Evacuation Cases are presented in Table 7-1 and Table 7-2. These tables present the estimated times to clear the indicated population percentages from the Evacuation Regions for all Evacuation Scenarios. The ETE of the 2-mile region in both staged and un-staged regions are presented in Table 7-3 and Table 7-4. Table 7-5 defines the Evacuation Regions considered. The tabulated values of ETE are obtained from the DYNEV II System outputs which are generated at 5-minute intervals.

7.1 Voluntary Evacuation and Shadow Evacuation

"Voluntary evacuees" are people within the EPZ in PAZ for which an Advisory to Evacuate has not been issued, yet who elect to evacuate. "Shadow evacuation" is the voluntary outward movement of some people from the Shadow Region (outside the EPZ) for whom no protective action recommendation has been issued. Both voluntary and shadow evacuations are assumed to take place over the same time frame as the evacuation from within the impacted Evacuation Region.

The ETE for the NAPS EPZ addresses the issue of voluntary evacuees in the manner shown in Figure 7-1. Within the EPZ, 20 percent of people located in PAZ outside of the evacuation region who are not advised to evacuate, are assumed to elect to evacuate. Similarly, it is assumed that 20 percent of those people in the Shadow Region will choose to leave the area.

Figure 7-2 presents the area identified as the Shadow Region. This region extends radially from the plant to cover a region between the EPZ boundary and approximately 15 miles. The population and number of evacuating vehicles in the Shadow Region were estimated using the same methodology that was used for permanent residents within the EPZ (see Section 3.1). As discussed in Section 3.2, it is estimated that a total of 31,947 people reside in the Shadow Region; 20 percent of them would evacuate. See Table 6-4 for the number of evacuating vehicles from the Shadow Region.

Traffic generated within this Shadow Region, traveling away from the NAPS location, has the potential for impeding evacuating vehicles from within the Evacuation Region. All ETE calculations include this shadow traffic movement.

7.2 Staged Evacuation

As defined in NUREG/CR-7002, staged evacuation consists of the following:

1. PAZ comprising the 2 mile region are advised to evacuate immediately.
2. PAZ comprising regions extending from 2 to 5 miles downwind are advised to shelter in-place while the two mile region is cleared.

3. As vehicles evacuate the 2 mile region, people from 2 to 5 miles downwind continue preparation for evacuation while they shelter.
4. The population sheltering in the 2 to 5 mile region is advised to evacuate when approximately 90% of the 2 mile region evacuating traffic crosses the 2 mile region boundary.
5. Non-compliance with the shelter recommendation is the same as the shadow evacuation percentage of 20%.

See Section 5.4.2 for additional information on staged evacuation.

7.3 Patterns of Traffic Congestion during Evacuation

Figure 7-3 through Figure 7-6 illustrate the patterns of traffic congestion that arise for the case when the entire EPZ (Region R03) is advised to evacuate during the summer, midweek, midday period under good weather conditions (Scenario 1).

Traffic congestion, as the term is used here, is defined as Level of Service (LOS) F. LOS F is defined as follows (HCM 2010, page 5-5):

> The HCM uses LOS F to define operations that have either broken down (i.e., demand exceeds capacity) or have exceeded a specified service measure value, or combination of service measure values, that most users would consider unsatisfactory. However, particularly for planning applications where different alternatives may be compared, analysts may be interested in knowing just how bad the LOS F condition is. Several measures are available to describe individually, or in combination, the severity of a LOS F condition:
>
> • *Demand-to-capacity ratios* describe the extent to which capacity is exceeded during the analysis period (e.g., by 1%, 15%, etc.);
>
> • *Duration of LOS F* describes how long the condition persists (e.g., 15 min, 1 h, 3 h); and
>
> • *Spatial extent measures* describe the areas affected by LOS F conditions. These include measures such as the back of queue, and the identification of the specific intersection approaches or system elements experiencing LOS F conditions.

Highway "links" which experience LOS F at the indicated times are delineated in these Figures by a red line; all others are lightly indicated.

At 30 minutes after the ATE, evacuees are beginning to mobilize. As shown in Figure 7-3, moderate traffic develops along SR-700 as employees evacuate from the plant.

At 50 minutes after the ATE, Figure 7-4 shows that there is no congestion within 5 miles of the plant. The town of Louisa experiences moderate levels of traffic (LOS D and LOS E) in the shadow, and congestion (LOS F) is exhibited on CR-601 northbound in the town of Granite Springs at the EPZ boundary. This congestion is due to the presence of a stop sign at the junction of CR-601 and CR-606. The intersections of SR 658 and SR 715 south of Beaverdam and US 522 and CR 612 also exhibit congestion due to the evacuation of seasonal summer residents on Lake Anna. The congestion at these two locations is due to the presence of stop-sign control.

At 1 hour and 30 minutes after the ATE, congestion has cleared on CR-601 in Granite Springs and CR 612 approaching US 522, as shown in Figure 7-5. Traffic has dissipated in the town of Louisa and congestion is still exhibited at the junction of SR 658 and SR 715.

At 2 hour and 10 minutes after the ATE, Figure 7-6 shows that traffic has subsided in the town of Louisa and the EPZ is completely clear of congestion. The last remnants of congestion, located outside of the Shadow Region at the junction of US 33 and SR 715 clears at 2 hours and 20 minutes after the ATE.

7.4 Evacuation Rates

Evacuation is a continuous process, as implied by Figure 7-7 through Figure 7-20. These Figures indicate the rate at which traffic flows out of the indicated areas for the case of an evacuation of the full EPZ (Region R03) under the indicated conditions. One figure is presented for each scenario considered.

As indicated in Figure 7-7, there is typically a long "tail" to these distributions. Vehicles begin to evacuate an area slowly at first, as people respond to the ATE at different rates. Then traffic demand builds rapidly (slopes of curves increase). When the system becomes congested, traffic exits the EPZ at rates somewhat below capacity until some evacuation routes have cleared. As more routes clear, the aggregate rate of egress slows since many vehicles have already left the EPZ. Towards the end of the process, relatively few evacuation routes service the remaining demand.

This decline in aggregate flow rate, towards the end of the process, is characterized by these curves flattening and gradually becoming horizontal. Ideally, it would be desirable to fully saturate all evacuation routes equally so that all will service traffic near capacity levels and all will clear at the same time. For this ideal situation, all curves would retain the same slope until the end – thus minimizing evacuation time. In reality, this ideal is generally unattainable reflecting the spatial variation in population density, mobilization rates and in highway capacity over the EPZ.

7.5 Evacuation Time Estimate (ETE) Results

Table 7-1 through Table 7-2 present the ETE values for all 41 Evacuation Regions and all 14 Evacuation Scenarios. Table 7-3 through Table 7-4 present the ETE values for the 2-Mile region for both staged and un-staged keyhole regions downwind to 5 miles. They are organized as follows:

Table	Contents
7-1	ETE represents the elapsed time required for 90 percent of the population within a Region, to evacuate from that Region. All Scenarios are considered, as well as Staged Evacuation scenarios.
7-2	ETE represents the elapsed time required for 100 percent of the population within a Region, to evacuate from that Region. All Scenarios are considered, as well as Staged Evacuation scenarios.
7-3	ETE represents the elapsed time required for 90 percent of the population within the 2-mile Region, to evacuate from that Region with both Concurrent and Staged Evacuations.
7-4	ETE represents the elapsed time required for 100 percent of the population within the 2-mile Region, to evacuate from that Region with both Concurrent and Staged Evacuations.

The animation snapshots described above reflect the ETE statistics for the concurrent (un-staged) evacuation scenarios and regions, which are displayed in Figure 7-3 through Figure 7-6. There is minimal traffic congestion within the EPZ, which results in ETE values which reflect mobilization time.

The 90th percentile ETE for weekday (non-snow) scenarios are approximately 45 minutes longer than weekend scenarios. As shown in Table 6-4, the ratio of households with returning commuters to that of employees and transients is approximately 5 to 10 times greater for weekdays compared with weekends. As shown in Figure 5-4, 90 percent of residents with commuters mobilize in about 185 minutes, whereas 90 percent of employees and transients mobilize in about 85 minutes. These factors lead to 90 percent of the population clearing the EPZ sooner in the weekend scenario.

The 100th percentile ETE for all Regions and for all Scenarios are the same values as the mobilization times, due to the fact that there is essentially no congestion within the EPZ and traffic is free-flowing prior to the end of mobilization, as is displayed in Figure 7-6.

Comparison of Scenarios 9 and 13 in Table 7-1 indicates that the special event, the Kinetic Triathlon at Lake Anna State Park (see Section 3.7), has no impact on the ETE at the 90th or 100th percentile. The results indicate there is sufficient reserve capacity to accommodate the additional special event vehicles.

Comparison of Scenarios 1 and 14 in Table 7-1 indicates that the roadway closure – one segment of US-522 northbound at CR-612 – increases the 90th percentile by at most 5 minutes and has no effect on the100th percentile ETE – not a significant impact. US-522 never experiences traffic congestion, and sufficient reserve capacity exists on CR-612 to service the additional evacuating traffic demand diverted from US-522.

7.6 Staged Evacuation Results

Table 7-3 and Table 7-4 present a comparison of the ETE compiled for the concurrent (un-staged) and staged evacuation studies. Note that Regions R29 through R41 are the same geographic areas as Regions R02 and R04 through R15, respectively.

To determine whether the staged evacuation strategy is worthy of consideration, one must show that the ETE for the 2 Mile region can be reduced without significantly affecting the region between 2 miles and 5 miles. As shown by Table 7-3 and Table 7-4, no benefit is gained from staging the evacuation; staging the evacuation to attempt to reduce congestion within the 5-mile area provides no benefits to evacuees from within the 2-mile region and unnecessarily delays the evacuation of those beyond 2 miles. The staged 90th percentile ETE, shown in Table 7-3, are generally 15 minutes longer than a concurrent evacuation. This results from vehicles evacuating from the 2 to 5-mile region passing through the 2-mile region to evacuate, primarily along SR-208 and CR-601.

While failing to provide assistance to evacuees from within 2 miles of the NAPS, staging produces a negative impact on the ETE for those evacuating from within the 5-mile area. A comparison of ETE between Regions, R29 through R41 with R02 and R04 through R15, respectively, reveals that staging retards the 90th percentile evacuation time for those in the 2 to 5-mile area by up to 35 minutes for non-snow cases (see Table 7-1). This extending of ETE is due to the delay in beginning the evacuation trip, experienced by those who shelter, plus the effect of the trip-generation "spike" (significant volume of traffic beginning the evacuation trip at the same time) that follows their eventual ATE, in creating congestion within the EPZ area beyond 2 miles.

In summary, the staged evacuation protective action strategy provides no benefits to evacuees from within 2 miles and adversely impacts many evacuees located beyond 2 miles from the NAPS. This fact is implied by the lack of congestion within 5 miles of the plant, as displayed in Figure 7-4.

7.7 Guidance on Using ETE Tables

The user first determines the percentile of population for which the ETE is sought (The NRC guidance calls for the 90th percentile). The applicable value of ETE within the chosen Table may then be identified using the following procedure:

1. Identify the applicable **Scenario**:
   - Season
     - Summer
     - Winter (also Autumn and Spring)
   - Day of Week

- Midweek
- Weekend
- Time of Day
  - Midday
  - Evening
- Weather Condition
  - Good Weather
  - Rain
  - Snow
- Special Event
  - Kinetic Triathlon at Lake Anna State Park
  - Road Closure (A segment on US-522 as explained in Section 2.2)
- Evacuation Staging
  - No, Staged Evacuation is not considered
  - Yes, Staged Evacuation is considered

While these Scenarios are designed, in aggregate, to represent conditions throughout the year, some further clarification is warranted:

- The conditions of a summer evening (either midweek or weekend) and rain are not explicitly identified in the Tables. For these conditions, Scenarios (2) and (4) apply.
- The conditions of a winter evening (either midweek or weekend) and rain are not explicitly identified in the Tables. For these conditions, Scenarios (7) and (10) for rain apply.
- The conditions of a winter evening (either midweek or weekend) and snow are not explicitly identified in the Tables. For these conditions, Scenarios (8) and (11) for snow apply.
- The seasons are defined as follows:
  - Summer assumes that public schools are not in session.
  - Winter (includes Spring and Autumn) considers that public schools are in session.
- Time of Day: Midday implies the time over which most commuters are at work or are travelling to/from work.

2. With the desired percentile ETE and Scenario identified, now identify the **Evacuation Region**:
   - Determine the projected azimuth direction of the plume (coincident with the wind direction). This direction is expressed in terms of compass orientation: towards N, NNE, NE, …
   - Determine the distance that the Evacuation Region will extend from the nuclear power plant. The applicable distances and their associated candidate Regions are given below:
     - 2 Miles (Region R01)
     - To 5 Miles (Region R02, R04 through R15)
     - To EPZ Boundary (Regions R03, R16 through R28)
   - Enter Table 7-5 and identify the applicable group of candidate Regions based on the

distance that the selected Region extends from the NAPS. Select the Evacuation Region identifier in that row, based on the azimuth direction of the plume, from the first column of the Table.

3. Determine the **ETE Table based on the percentile selected. Then, for the Scenario** identified in Step 1 and the **Region** identified in Step 2, proceed as follows:
   - The columns of Table 7-1 are labeled with the Scenario numbers. Identify the proper column in the selected Table using the Scenario number defined in Step 1.
   - Identify the row in this table that provides ETE values for the Region identified in Step 2.
   - The unique data cell defined by the column and row so determined contains the desired value of ETE expressed in Hours:Minutes.

<u>Example</u>

It is desired to identify the ETE for the following conditions:

- Sunday, August 10th at 4:00 AM.
- It is raining.
- Wind direction is toward the northeast (NE).
- Wind speed is such that the distance to be evacuated is judged to be a 5-mile radius and downwind to 10 miles (to EPZ boundary).
- The desired ETE is that value needed to evacuate 90 percent of the population from within the impacted Region.
- A staged evacuation is not desired.

Table 7-1 is applicable because the 90th percentile ETE is desired. Proceed as follows:

1. Identify the Scenario as summer, weekend, evening and raining. Entering Table 7-1, it is seen that there is no match for these descriptors. However, the clarification given above assigns this combination of circumstances to Scenario 4.
2. Enter Table 7-5 and locate the Region described as “Evacuate 5-Mile Radius and Downwind to the EPZ Boundary” for wind direction toward the NE and read Region R18 in the first column of that row.
3. Enter Table 7-1 to locate the data cell containing the value of ETE for Scenario 4 and Region R18. This data cell is in column (4) and in the row for Region R18; it contains the ETE value of **1:55**.

Table 7-1. Time to Clear the Indicated Area of *90* Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:30
R02	2:25	2:25	1:50	1:50	1:50	2:30	2:35	3:25	1:50	1:50	2:55	1:55	1:50	2:30
R03	2:35	2:35	2:00	2:00	2:00	2:40	2:40	3:30	2:00	2:00	3:05	2:00	2:00	2:35
2-Mile Region and Keyhole to 5 Miles														
R04	2:20	2:20	1:45	1:45	1:45	2:30	2:30	3:15	1:50	1:50	2:55	1:50	1:50	2:20
R05	2:25	2:25	1:50	1:50	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R07	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:25
R08	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:15	2:20	1:50	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R10	2:15	2:15	1:50	1:50	1:50	2:20	2:20	3:05	1:50	1:50	2:50	1:50	1:50	2:20
R11	2:20	2:20	1:50	1:50	1:50	2:25	2:25	3:15	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:15	2:20	1:50	1:50	1:50	2:20	2:25	3:10	1:50	1:50	2:50	1:50	1:50	2:20
R13	2:20	2:20	1:45	1:50	1:50	2:25	2:25	3:10	1:50	1:50	2:55	1:50	1:50	2:20
R14	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
R15	2:15	2:15	1:45	1:45	1:45	2:25	2:25	3:15	1:50	1:50	2:50	1:50	1:50	2:20
5-Mile Region and Keyhole to EPZ Boundary														
R16	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R17	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R18	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R19	2:30	2:35	1:55	1:55	1:55	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R20	2:30	2:35	1:55	1:55	1:55	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R21	2:35	2:35	2:00	2:05	2:05	2:40	2:40	3:30	2:00	2:00	3:00	2:00	2:00	2:35
R22	2:30	2:35	2:00	2:00	2:05	2:35	2:40	3:30	1:55	1:55	3:00	1:55	1:55	2:35
R23	2:30	2:30	2:00	2:00	2:00	2:35	2:35	3:30	1:55	1:55	3:00	1:55	1:55	2:35

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
Region	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R24	2:30	2:30	1:50	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R25	2:30	2:30	1:55	1:55	1:55	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:35
R26	2:30	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	3:00	1:55	1:55	2:30
R27	2:25	2:30	1:50	1:50	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
R28	2:30	2:30	1:55	1:55	1:50	2:35	2:35	3:25	1:55	1:55	2:55	1:55	1:55	2:30
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:10	2:15	3:30	2:10	2:10	2:55
R30	2:55	2:55	2:10	2:10	2:10	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R31	2:55	2:55	2:15	2:15	2:15	2:55	2:55	3:45	2:15	2:15	3:30	2:15	2:15	2:55
R32	2:50	2:50	2:10	2:10	2:10	2:50	2:55	3:40	2:10	2:10	3:25	2:10	2:10	2:50
R33	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:25	2:05	2:05	2:50
R34	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R35	2:45	2:45	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:10	3:25	2:05	2:05	2:50
R36	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:30	2:05	2:05	3:20	2:05	2:05	2:45
R37	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R38	2:45	2:45	2:05	2:05	2:05	2:45	2:45	3:35	2:05	2:05	3:20	2:05	2:05	2:45
R39	2:45	2:50	2:05	2:05	2:05	2:50	2:50	3:35	2:05	2:05	3:20	2:05	2:05	2:50
R40	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:10	3:25	2:05	2:05	2:50
R41	2:50	2:50	2:05	2:05	2:05	2:50	2:50	3:40	2:05	2:05	3:25	2:05	2:05	2:50

Table 7-2. Time to Clear the Indicated Area of *100* Percent of the Affected Population

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Midday	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region, 5-Mile Region, and EPZ														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R03	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
2-Mile Region and Keyhole to 5 Miles														
R04	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R05	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R06	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R07	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R08	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R09	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R10	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R11	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R12	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R13	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R14	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R15	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
5-Mile Region and Keyhole to EPZ Boundary														
R16	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R17	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R18	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R19	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R20	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R21	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R22	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R23	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	**Midday**		**Midday**		**Evening**	**Midday**			**Midday**			**Evening**	**Midday**	**Midday**
	Good Weather	**Rain**	**Good Weather**	**Rain**	**Good Weather**	**Good Weather**	**Rain**	**Snow**	**Good Weather**	**Rain**	**Snow**	**Good Weather**	**Special Event**	**Roadway Impact**
R24	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R25	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R26	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R27	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
R28	5:40	5:40	5:40	5:40	5:40	5:40	5:40	6:40	5:40	5:40	6:40	5:40	5:40	5:40
Staged Evacuation - 2-Mile Region and Keyhole to 5 Miles														
R29	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R30	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R31	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R32	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R33	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R34	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R35	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R36	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R37	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R38	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R39	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R40	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35
R41	5:35	5:35	5:35	5:35	5:35	5:35	5:35	6:35	5:35	5:35	6:35	5:35	5:35	5:35

Table 7-3. Time to Clear *90* Percent of the 2-Mile Area within the Indicated Region

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R02	2:25	2:25	1:45	1:50	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R05	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
R06	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R07	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R08	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R09	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R10	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R11	2:25	2:25	1:45	1:45	1:50	2:35	2:35	3:25	1:50	1:50	2:55	1:50	1:50	2:25
R12	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R13	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R14	2:25	2:25	1:45	1:45	1:45	2:30	2:30	3:20	1:50	1:50	2:50	1:50	1:50	2:25
R15	2:25	2:25	1:45	1:45	1:50	2:30	2:30	3:20	1:50	1:50	2:55	1:50	1:50	2:25
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45
R30	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R31	2:40	2:40	1:55	1:55	1:55	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R32	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R33	2:35	2:40	1:55	1:55	1:55	2:40	2:40	3:30	2:00	2:00	3:10	2:00	2:00	2:35
R34	2:40	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R35	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R36	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:45
R37	2:45	2:45	2:00	2:00	2:00	2:45	2:45	3:35	2:00	2:00	3:15	2:00	2:00	2:45

	Summer		Summer		Summer	Winter			Winter			Winter	Winter	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R38	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R39	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R40	2:40	2:40	2:00	2:00	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40
R41	2:40	2:40	1:55	1:55	2:00	2:45	2:45	3:30	2:00	2:00	3:15	2:00	2:00	2:40

Table 7-4. Time to Clear *100* Percent of the 2-Mile Area within the Indicated Region

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
Entire 2-Mile Region and 5-Mile Region														
R01	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R02	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Unstaged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R04	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R05	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R06	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R07	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R08	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R09	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R10	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R11	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R12	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R13	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R14	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R15	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
Staged Evacuation - 2-Mile Region and Keyhole to 5-Miles														
R29	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R30	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R31	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R32	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R33	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R34	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R35	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R36	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R37	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

	Summer		Summer		Summer	Winter			Winter			Winter	May	Summer
	Midweek		Weekend		Midweek Weekend	Midweek			Weekend			Midweek Weekend	Weekend	Midweek
Scenario:	**(1)**	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**	**(13)**	**(14)**
Region	Midday		Midday		Evening	Midday			Midday			Evening	Evening	Midday
	Good Weather	Rain	Good Weather	Rain	Good Weather	Good Weather	Rain	Snow	Good Weather	Rain	Snow	Good Weather	Special Event	Roadway Impact
R38	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R39	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R40	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30
R41	5:30	5:30	5:30	5:30	5:30	5:30	5:30	6:30	5:30	5:30	6:30	5:30	5:30	5:30

Table 7-5. Description of Evacuation Regions

Region	Description	Site PAR Description	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
			Protection Action Zone (PAZ)																								
R01	2-Mile Radius	2- Mile Radius					x		x	x	x																
R02	5-Mile Radius	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R03	Full EPZ	Full EPZ	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Evacuate 2-Mile Radius and Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R04	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R05	NE	34° - 56°					x		x	x	x	x	x	x													
R06	ENE, E	57° - 101°					x		x	x	x	x	x														
R07	ESE	102° - 123°					x		x	x	x	x														x	
R08	SE	124° - 146°					x	x	x	x	x	x														x	
R09	SSE, S	147° - 191°					x	x	x	x	x															x	
R10	SSW	192° - 213°					x	x	x	x	x																
R11	SW	214° - 236°			x		x	x	x	x	x																
R12	WSW	237° - 258°			x		x		x	x	x																
R13	W	259°- 281°			x		x		x	x	x					x											
R14	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R15	NNW	327° - 349°					x		x	x	x			x	x	x											
Evacuate 5-Mile Radius and Downwind to the EPZ Boundary																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R16	N	349° - 11°			x		x	x	x	x	x	x	x	x	x	x			x	x	x					x	
R17	NNE	12° - 33°			x		x	x	x	x	x	x	x	x	x	x			x	x	x	x				x	
R18	NE	34° - 56°			x		x	x	x	x	x	x	x	x	x	x				x	x	x				x	
R19	ENE	57° - 78°			x		x	x	x	x	x	x	x	x	x	x					x	x	x			x	
R20	E	79° - 101°			x		x	x	x	x	x	x	x	x	x	x						x	x	x		x	
R21	ESE	102° - 123°			x		x	x	x	x	x	x	x	x	x	x						x	x	x	x	x	x
R22	SE	124° - 146°			x		x	x	x	x	x	x	x	x	x	x							x	x	x	x	x
R23	SSE, S	147° - 191°			x	x	x	x	x	x	x	x	x	x	x	x									x	x	x
R24	SSW	192° - 213°		x	x	x	x	x	x	x	x	x	x	x	x	x										x	x
R25	SW, WSW	214° - 258°	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x									x	
R26	W	259° - 281°	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R27	WNW, NW	282° - 326°			x		x	x	x	x	x	x	x	x	x	x	x	x	x							x	
R28	NNW	327° - 349°			x		x	x	x	x	x	x	x	x	x	x		x	x	x						x	
Staged Evacuation - 2-Mile Radius Evacuates, then Evacuate Downwind to 5 Miles																											
Region	**Wind Direction Toward:**	**Site PAR Description**	**Protection Action Zone (PAZ)**																								
			2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
R29	-	5-Mile Radius			x		x	x	x	x	x	x	x	x	x	x										x	
R30	N, NNE	349° - 33°					x		x	x	x		x	x	x												
R31	NE	34° - 56°					x		x	x	x	x	x	x													
R32	ENE, E	57° - 101°					x		x	x	x	x	x														
R33	ESE	102° - 123°					x		x	x	x	x														x	
R34	SE	124° - 146°					x	x	x	x	x	x														x	
R35	SSE, S	147° - 191°					x	x	x	x	x															x	
R36	SSW	192° - 213°					x	x	x	x	x																
R37	SW	214° - 236°			x		x	x	x	x	x																
R38	WSW	237° - 258°			x		x		x	x	x																
R39	W	259°- 281°			x		x		x	x	x					x											
R40	WNW, NW	282° - 326°			x		x		x	x	x				x	x											
R41	NNW	327° - 349°					x		x	x	x			x	x	x											

Shelter-in-Place until 90% ETE for R01, then Evacuate	PAZ Shelter-in-Place	PAZ Evacuate

Figure 7-1. Voluntary Evacuation Methodology

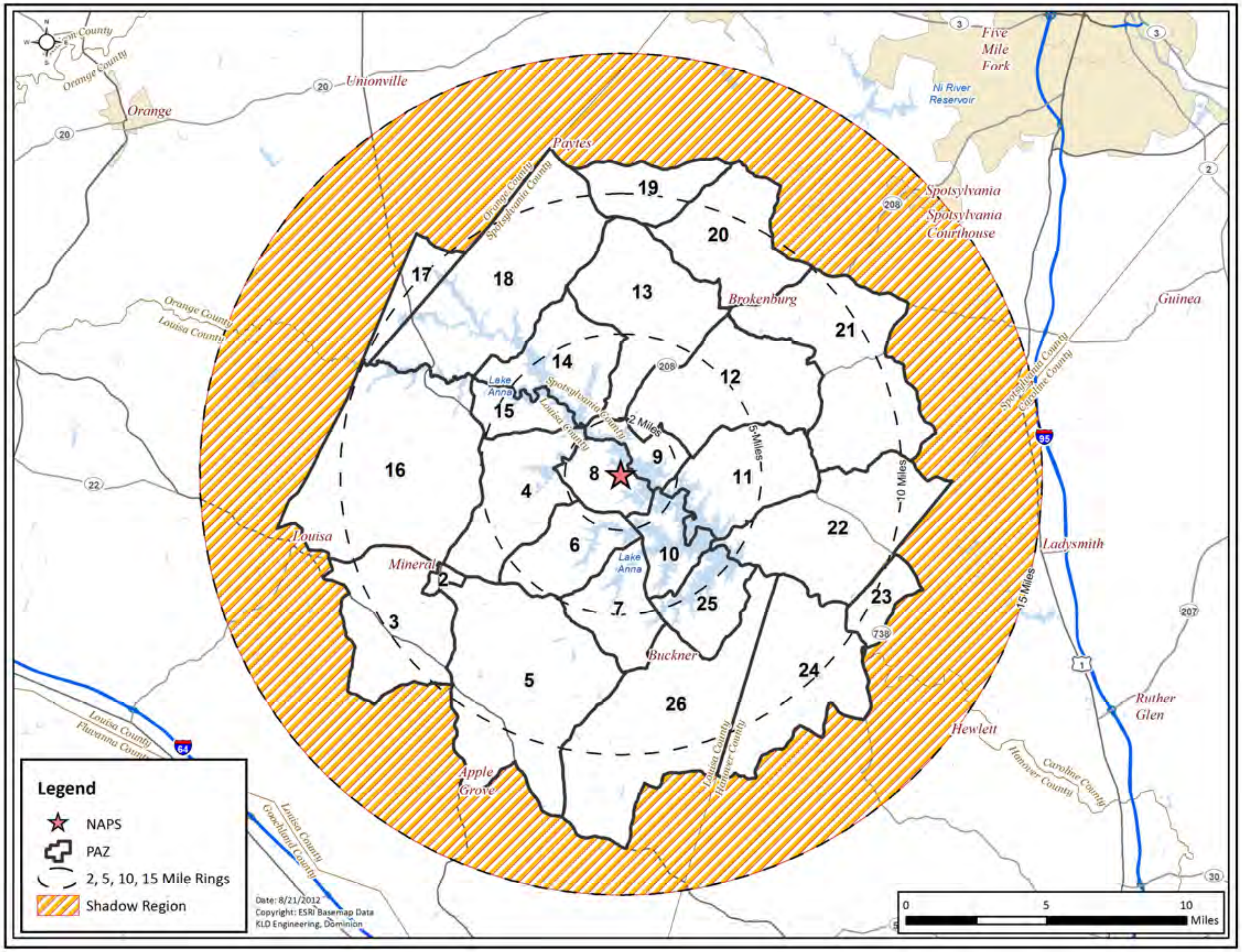


Figure 7-2. NAPS Shadow Region

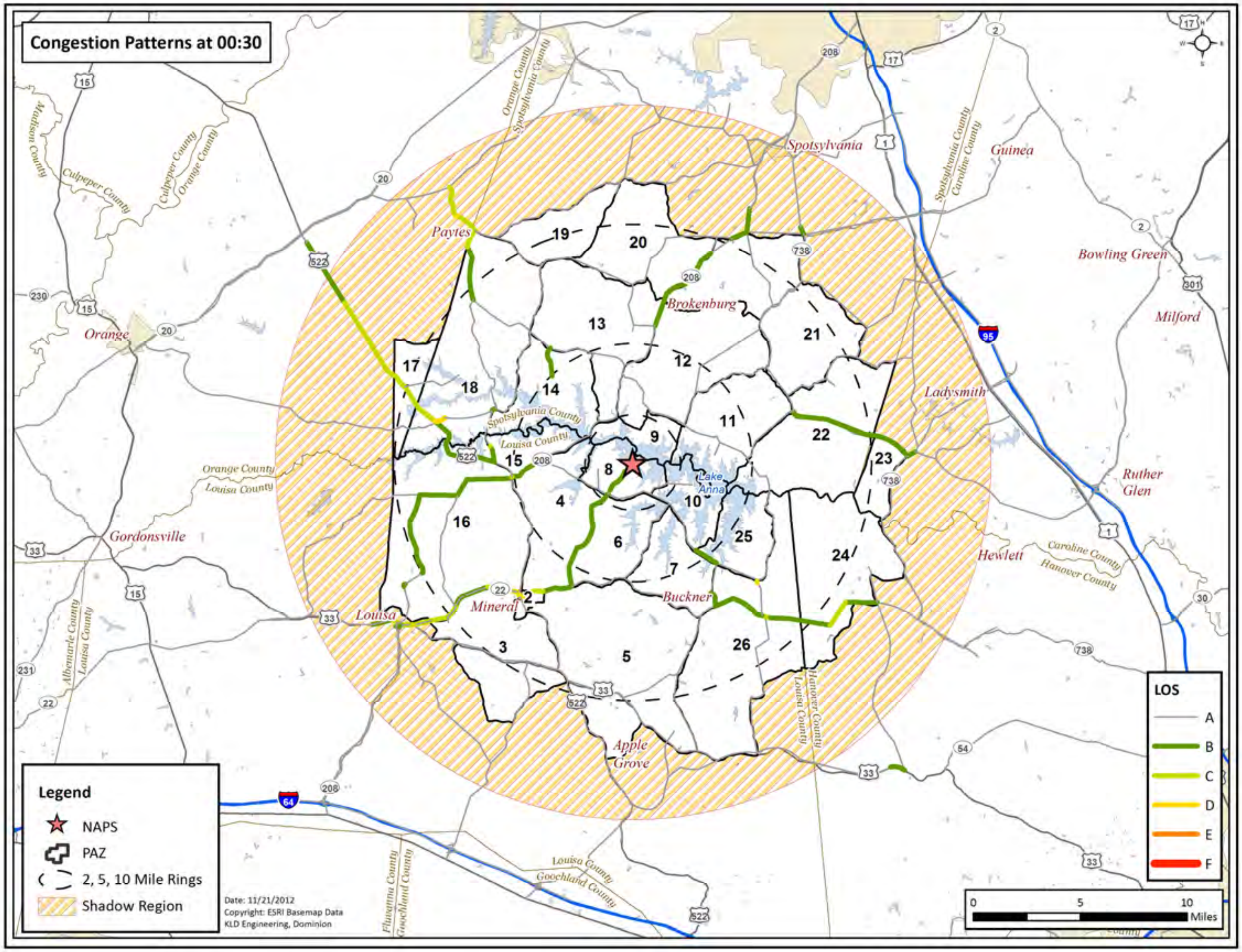


Figure 7-3. Congestion Patterns at 30 Minutes after the Advisory to Evacuate

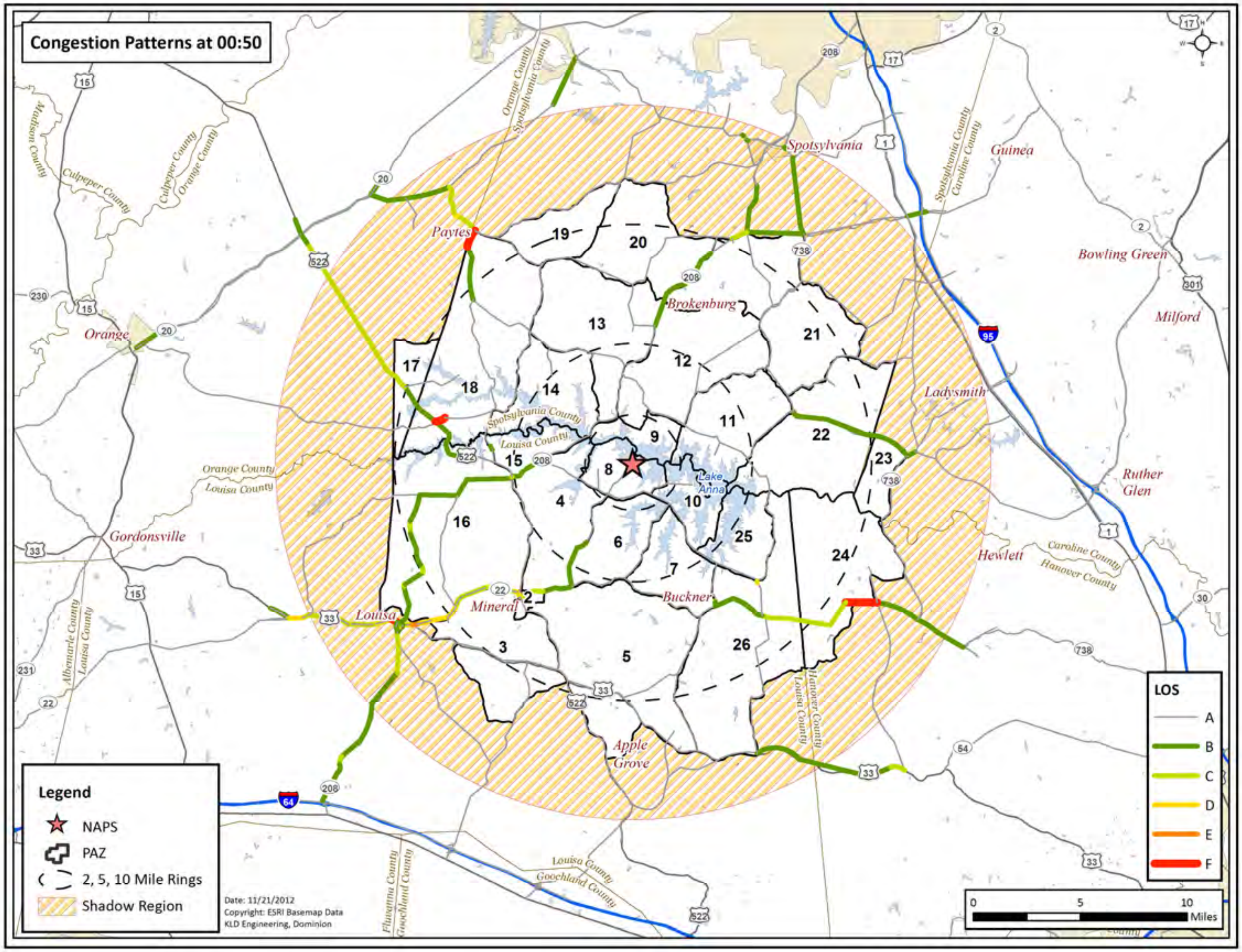


Figure 7-4. Congestion Patterns at 50 Minutes after the Advisory to Evacuate

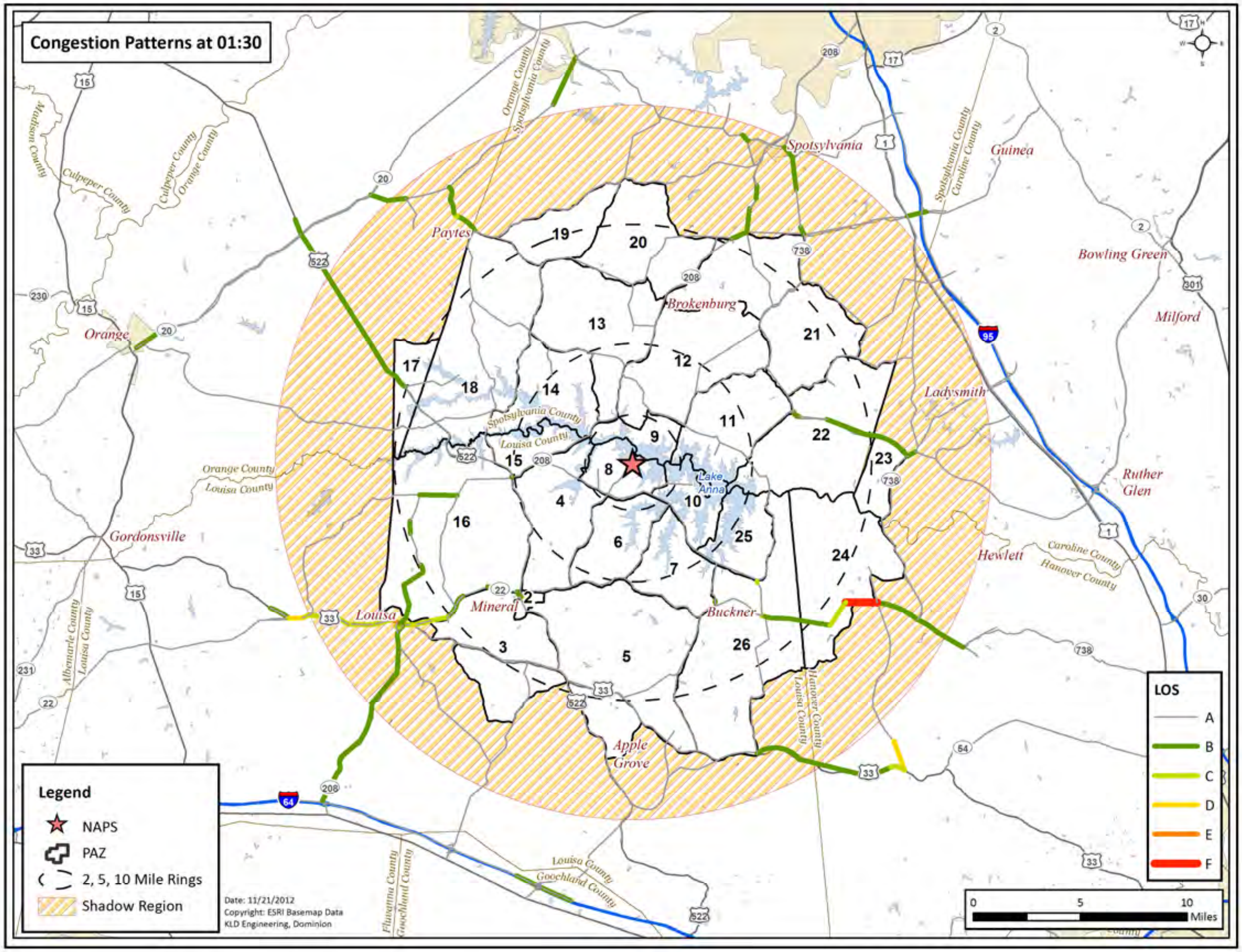


Figure 7-5. Congestion Patterns at 1 Hour 30 Minutes after the Advisory to Evacuate

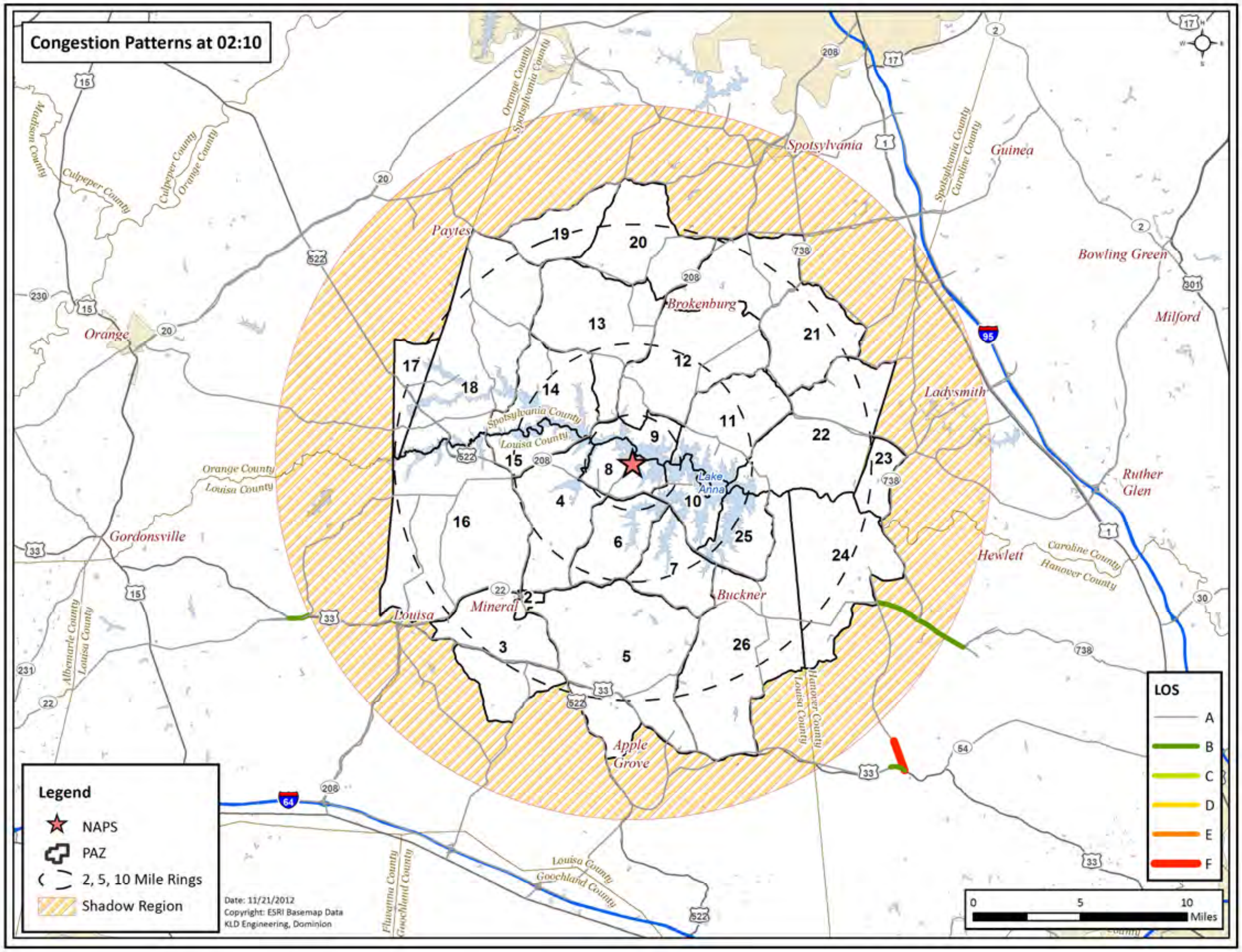


Figure 7-6. Congestion Patterns at 2 Hours 10 Minutes after the Advisory to Evacuate

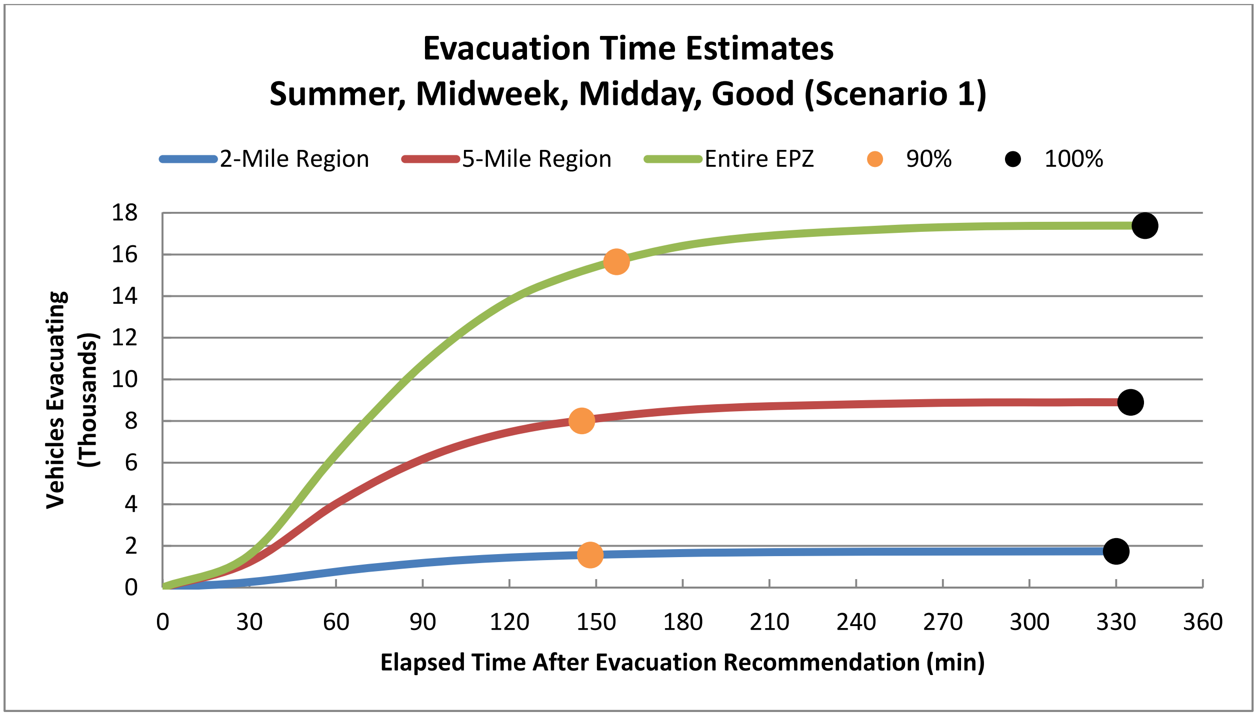


Figure 7-7. Evacuation Time Estimates - Scenario 1 for Region R03

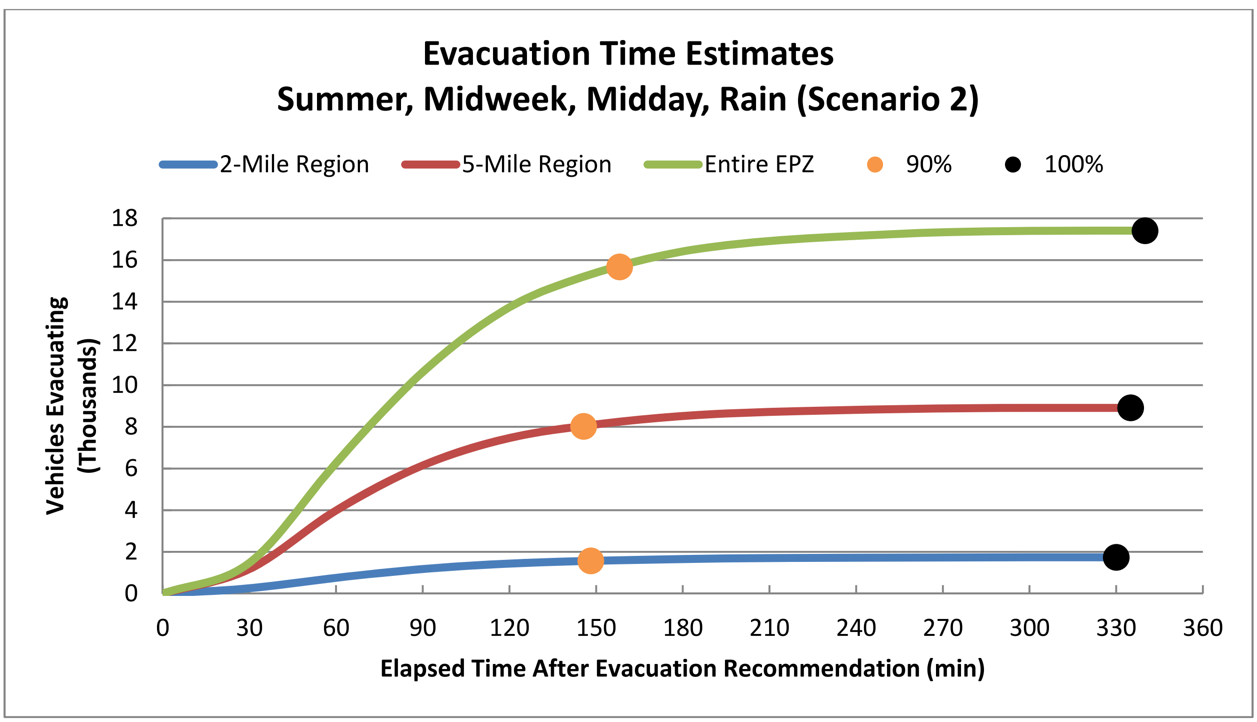


Figure 7-8. Evacuation Time Estimates - Scenario 2 for Region R03

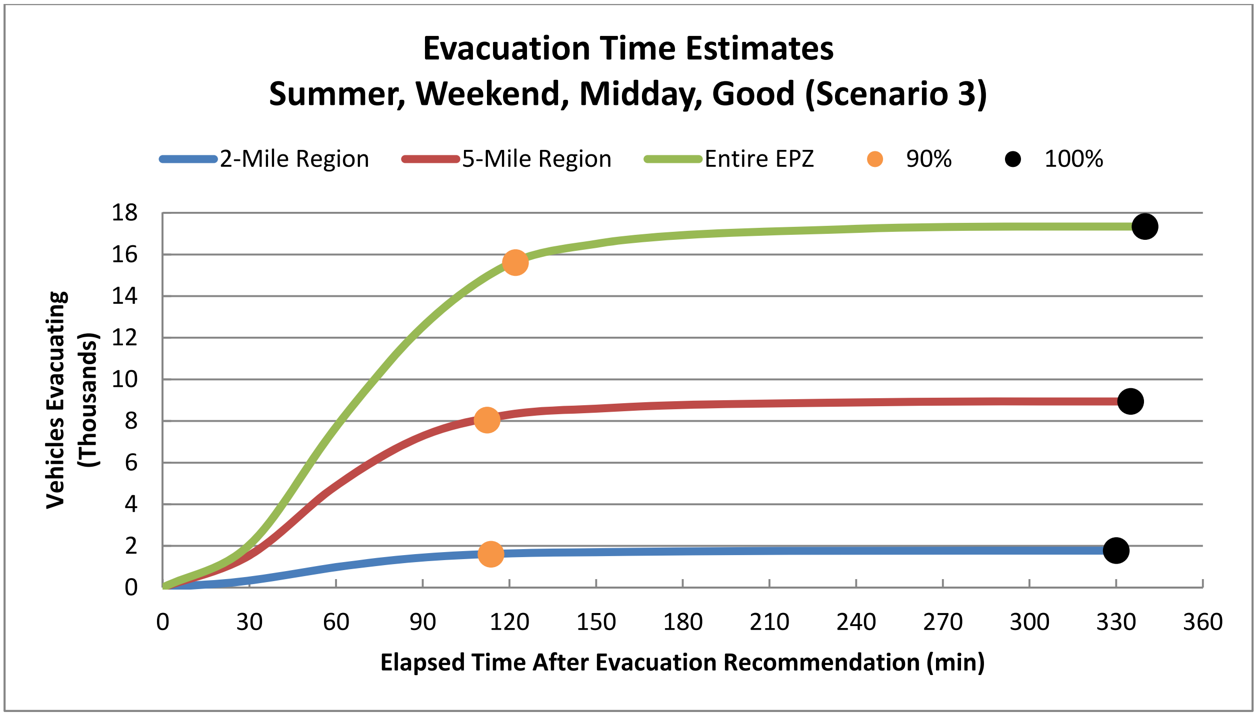


Figure 7-9. Evacuation Time Estimates - Scenario 3 for Region R03

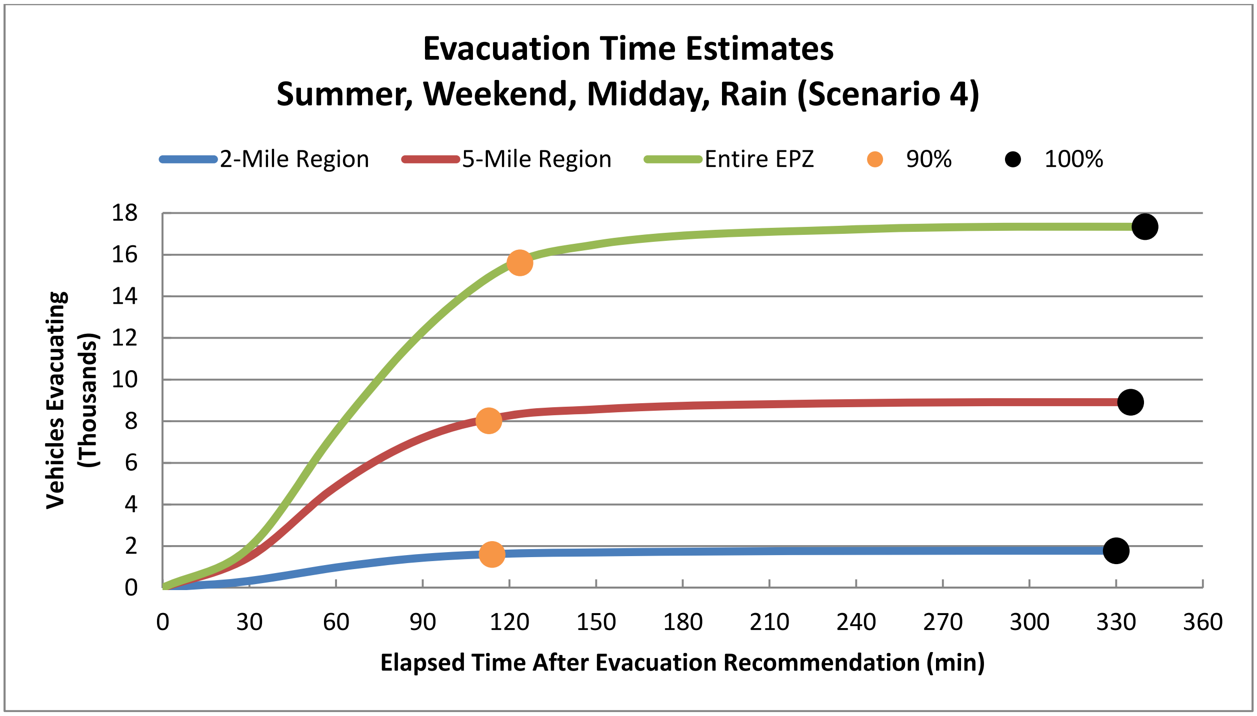


Figure 7-10. Evacuation Time Estimates - Scenario 4 for Region R03

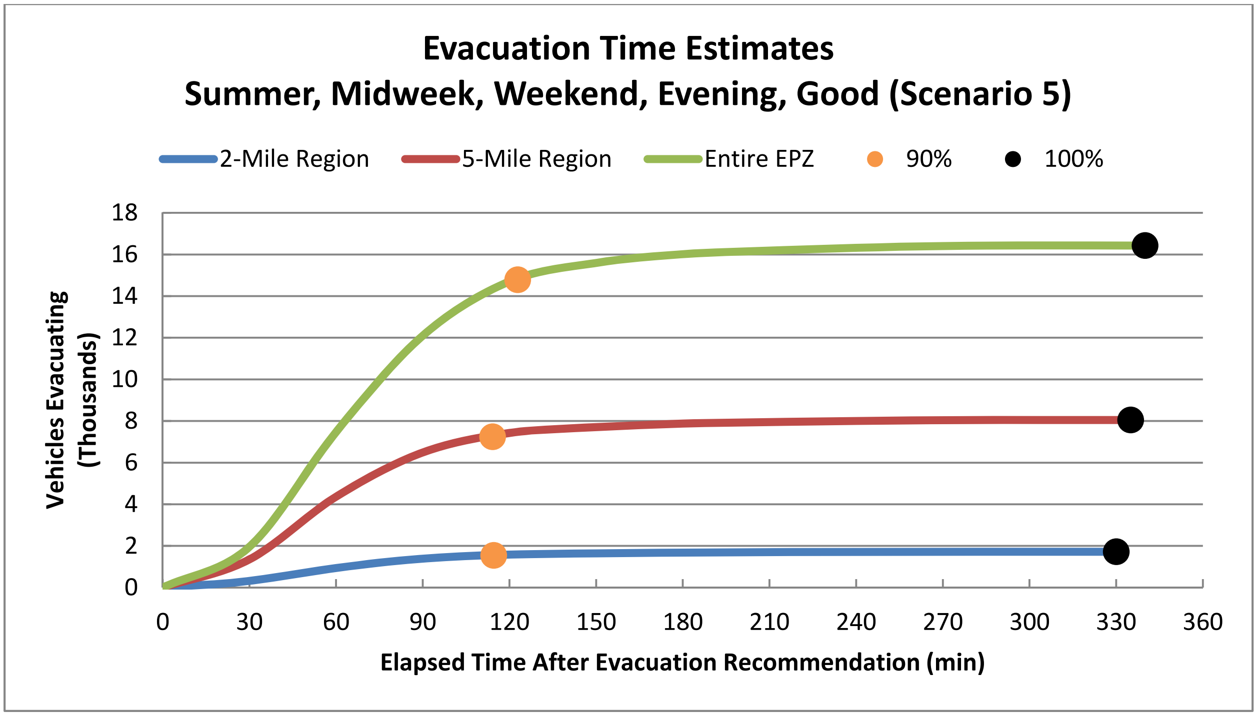


Figure 7-11. Evacuation Time Estimates - Scenario 5 for Region R03

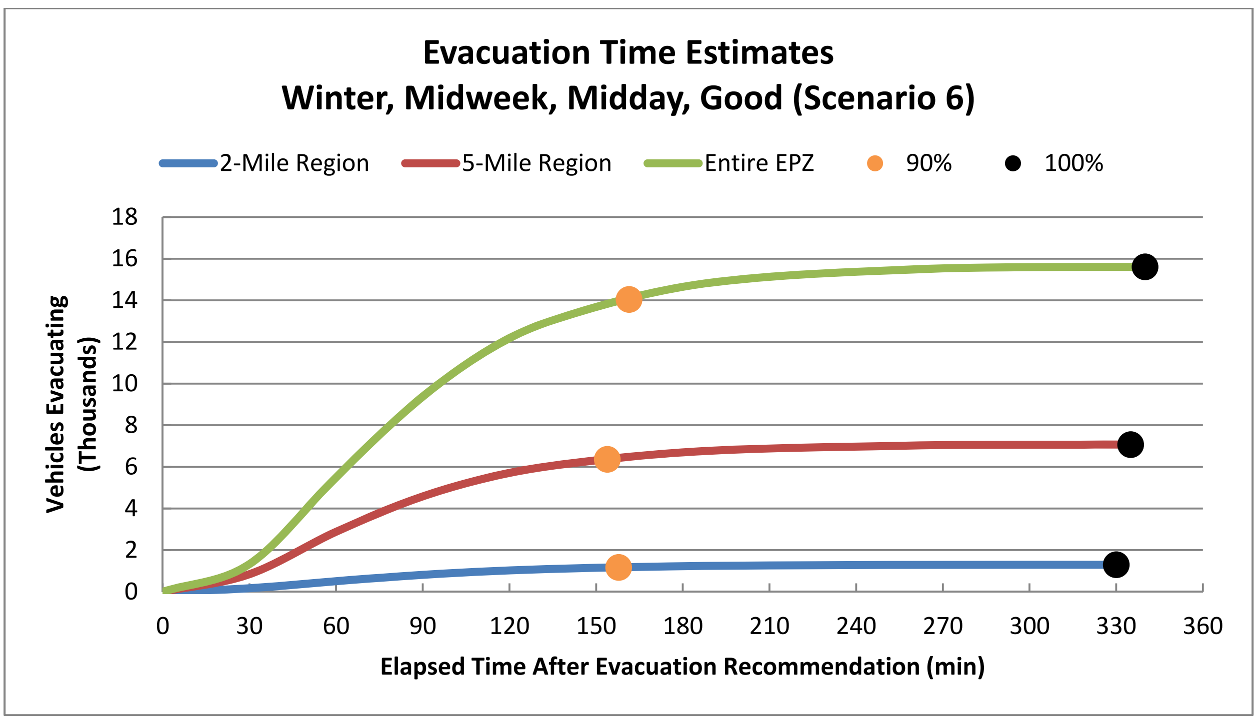


Figure 7-12. Evacuation Time Estimates - Scenario 6 for Region R03

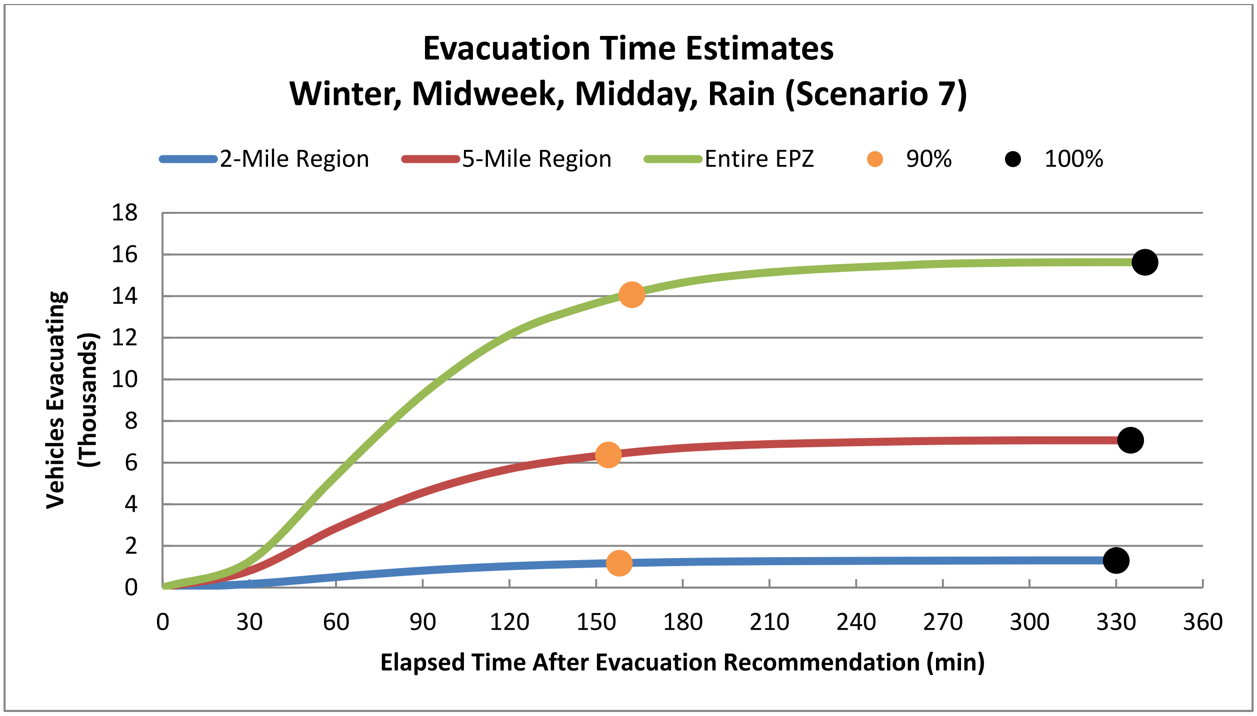


Figure 7-13. Evacuation Time Estimates - Scenario 7 for Region R03

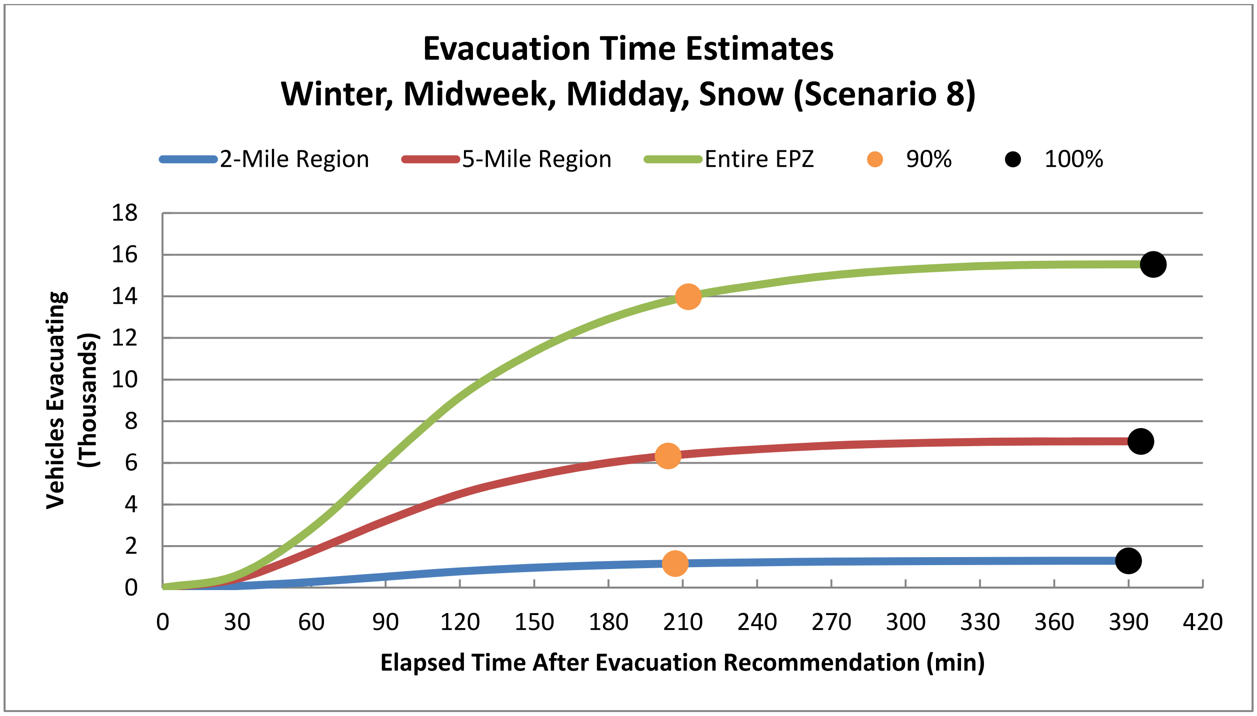


Figure 7-14. Evacuation Time Estimates - Scenario 8 for Region R03

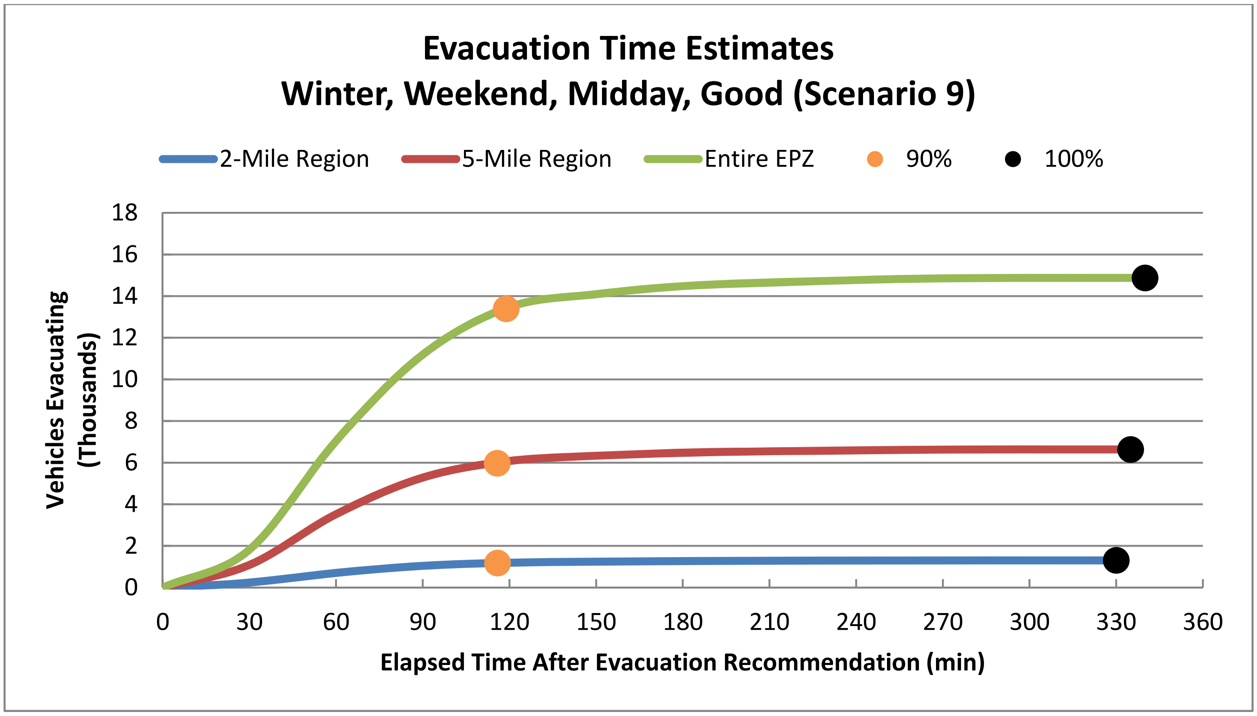


Figure 7-15. Evacuation Time Estimates - Scenario 9 for Region R03

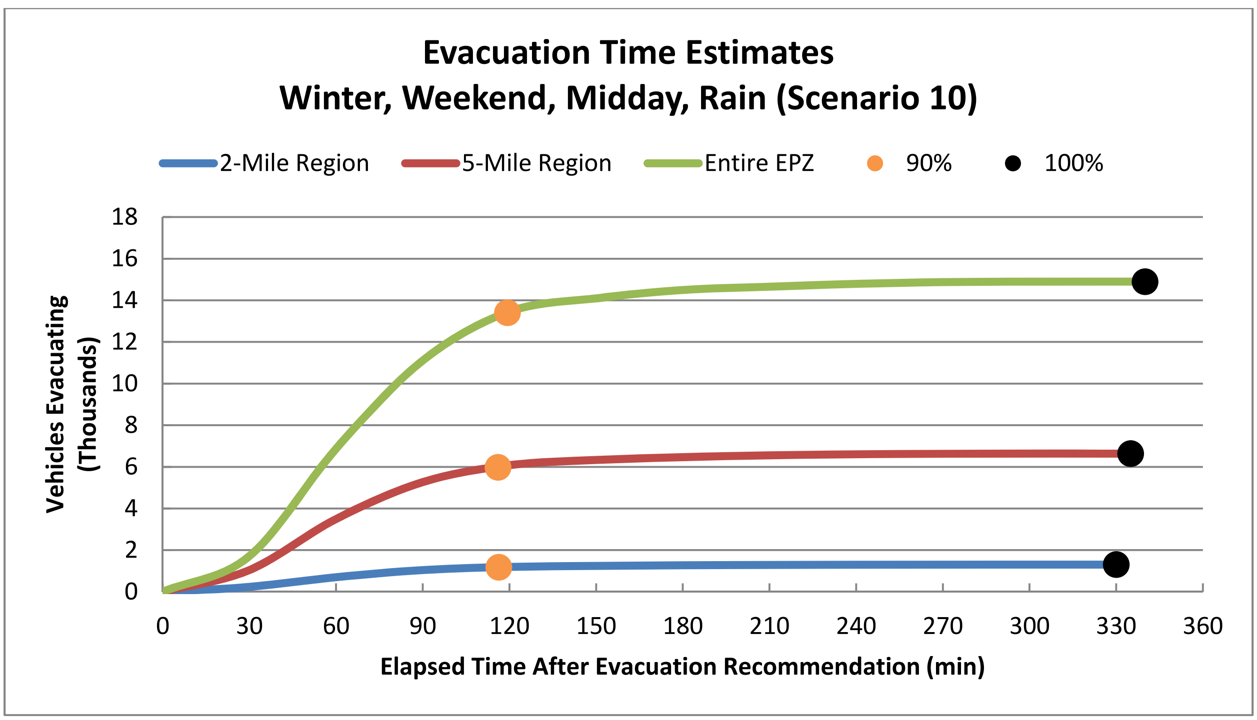


Figure 7-16. Evacuation Time Estimates - Scenario 10 for Region R03

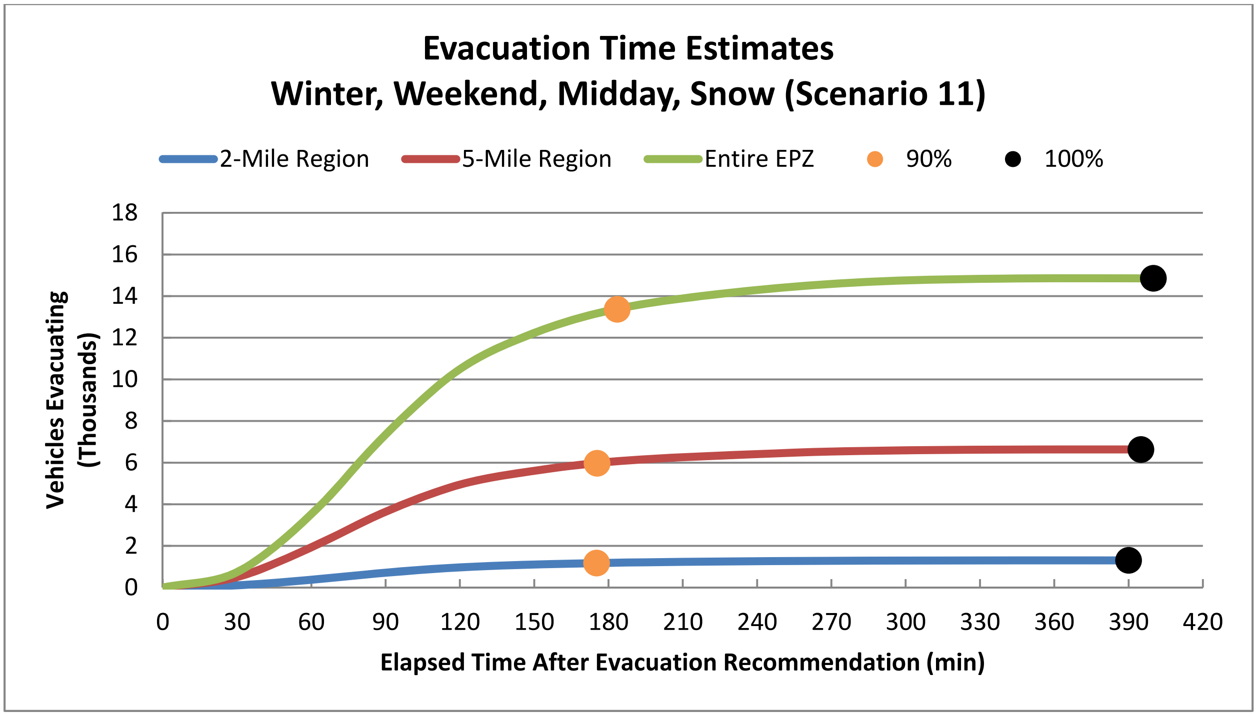


Figure 7-17. Evacuation Time Estimates - Scenario 11 for Region R03

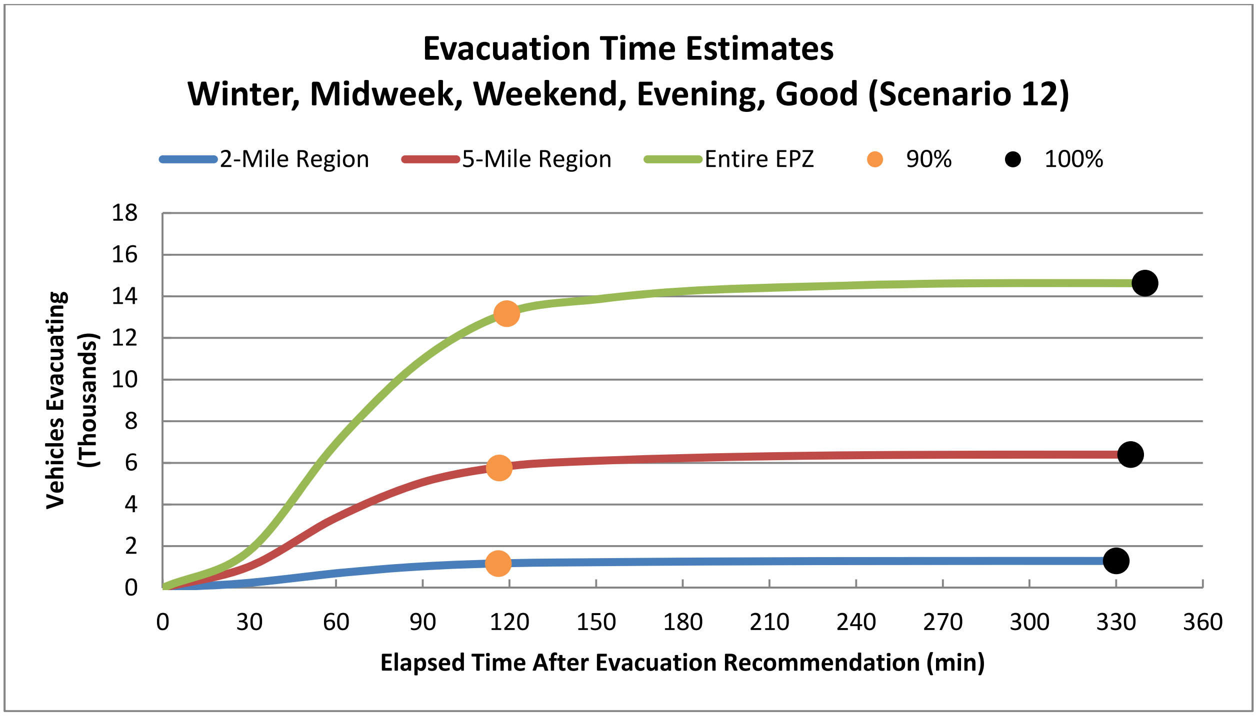


Figure 7-18. Evacuation Time Estimates - Scenario 12 for Region R03

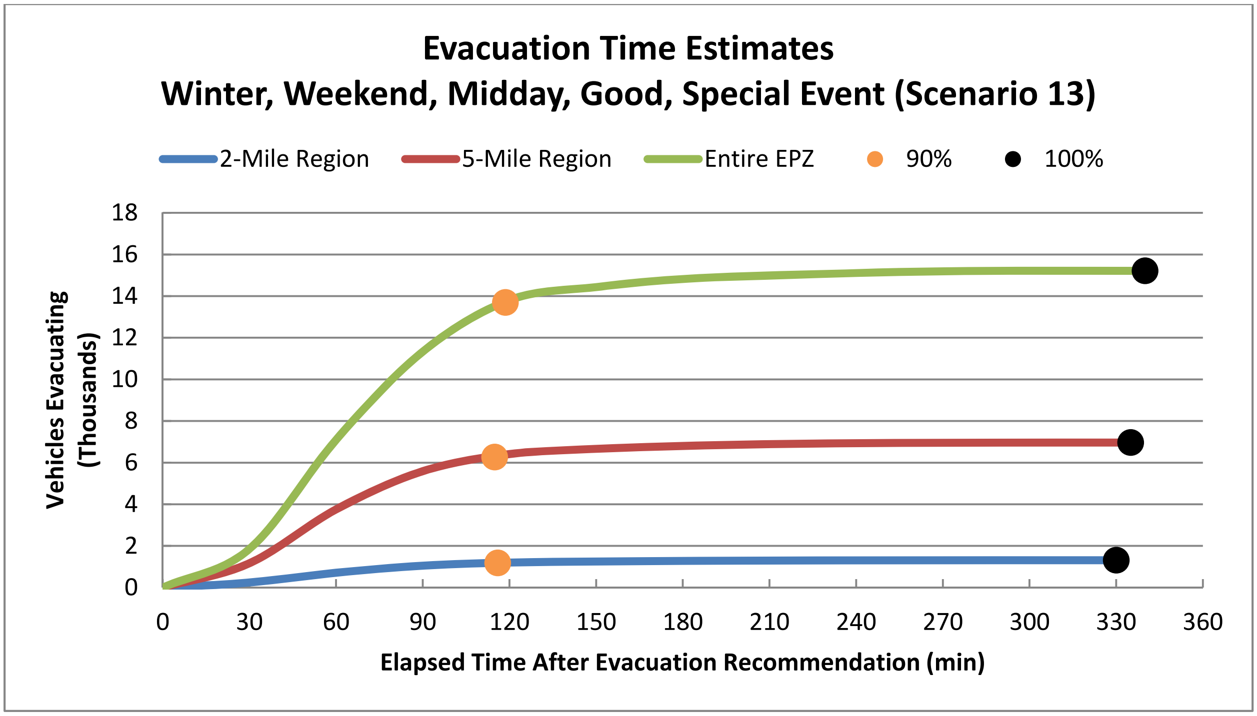


Figure 7-19. Evacuation Time Estimates - Scenario 13 for Region R03

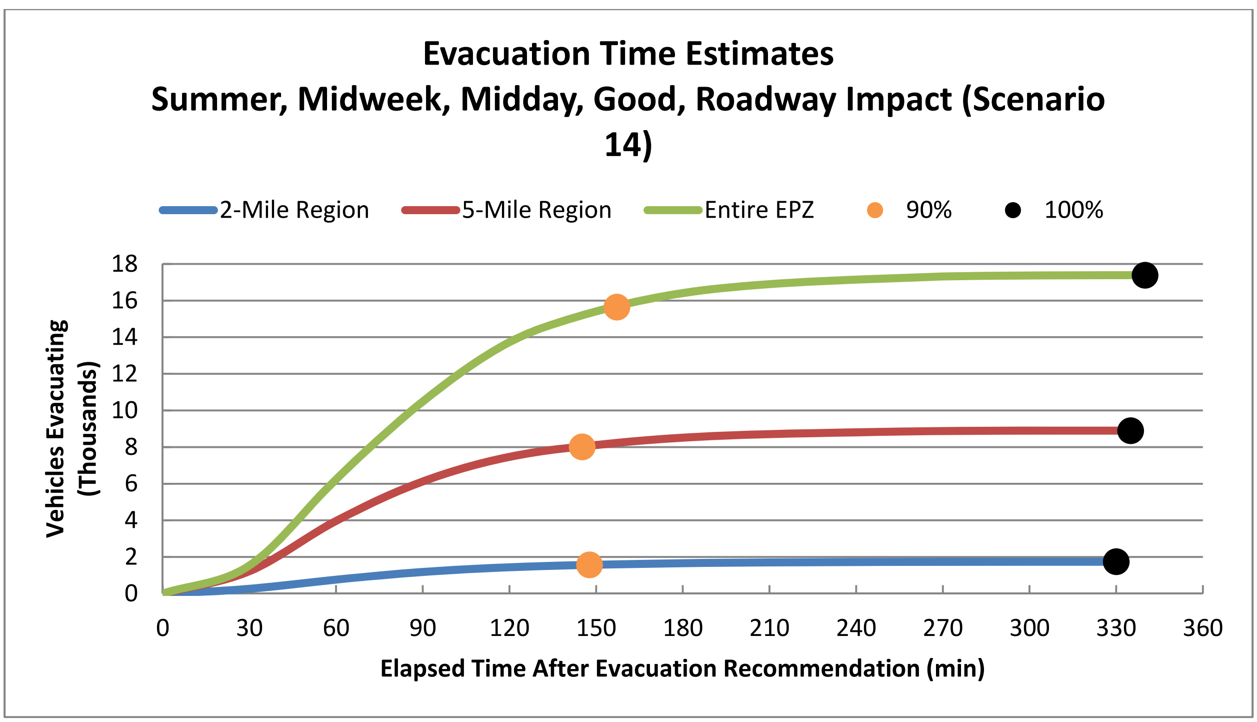


Figure 7-20. Evacuation Time Estimates - Scenario 14 for Region R03

8 TRANSIT-DEPENDENT AND SPECIAL FACILITY EVACUATION TIME ESTIMATES

This section details the analyses applied and the results obtained in the form of evacuation time estimates for transit vehicles. The demand for transit service reflects the needs of three population groups: (1) residents with no vehicles available; (2) residents of special facilities such as schools, medical facilities; and (3) homebound special needs population.

These transit vehicles mix with the general evacuation traffic that is comprised mostly of "passenger cars" (pc's). The presence of each transit vehicle in the evacuating traffic stream is represented within the modeling paradigm described in Appendix D as equivalent to two pc's. This equivalence factor represents the longer size and more sluggish operating characteristics of a transit vehicle, relative to those of a pc.

Transit vehicles must be mobilized in preparation for their respective evacuation missions. Specifically:

- Bus drivers must be alerted
- They must travel to the bus depot
- They must be briefed there and assigned to a route or facility

These activities consume time. Based on discussion with the offsite agencies, it is estimated that school bus mobilization time will average approximately 90 minutes extending from the Advisory to Evacuate, to the time when buses first arrive at the facility to be evacuated.

During this mobilization period, other mobilization activities are taking place. One of these is the action taken by parents, neighbors, relatives and friends to pick up children from school prior to the arrival of buses, so that they may join their families. Virtually all studies of evacuations have concluded that this "bonding" process of uniting families is universally prevalent during emergencies and should be anticipated in the planning process. The current public information disseminated to residents of the NAPS EPZ indicates that schoolchildren will be evacuated to Evacuation Assembly Centers (EAC) at emergency action levels of Site Area Emergency or higher, and that parents should pick schoolchildren up at the EAC. As discussed in Section 2, this study assumes a fast breaking general emergency. Therefore, children are evacuated to the EAC. Picking up children at school could add to traffic congestion at the schools, delaying the departure of the buses evacuating schoolchildren, which may have to return in a subsequent "wave" to the EPZ to evacuate the transit-dependent population. This report provides estimates of buses under the assumption that no children will be picked up by their parents (in accordance with NUREG/CR-7002), to present an upper bound estimate of buses required.

The procedure for computing transit-dependent ETE is to:

- Estimate demand for transit service
- Estimate time to perform all transit functions
- Estimate route travel times to the EPZ boundary and to the EAC

8.1 Transit Dependent People Demand Estimate

The telephone survey (see Appendix F) results were used to estimate the portion of the population requiring transit service:

- Those persons in households that do not have a vehicle available.
- Those persons in households that do have vehicle(s) that would not be available at the time the evacuation is advised.

In the latter group, the vehicle(s) may be used by a commuter(s) who does not return (or is not expected to return) home to evacuate the household.

Table 8-1 presents estimates of transit-dependent people. Note:

- Estimates of persons requiring transit vehicles include schoolchildren. For those evacuation scenarios where children are at school when an evacuation is ordered, separate transportation is provided for the schoolchildren. The actual need for transit vehicles by residents is thereby less than the given estimates. However, estimates of transit vehicles are not reduced when schools are in session.
- It is reasonable and appropriate to consider that many transit-dependent persons will evacuate by ride-sharing with neighbors, friends or family. For example, nearly 80 percent of those who evacuated from Mississauga, Ontario who did not use their own cars, shared a ride with neighbors or friends. Other documents report that approximately 70 percent of transit dependent persons were evacuated via ride sharing. **We will adopt a conservative estimate that 50 percent of transit dependent persons will ride share, in accordance with NUREG/CR-7002.**

The estimated number of bus trips needed to service transit-dependent persons is based on an estimate of average bus occupancy of 30 persons at the conclusion of the bus run. Transit vehicle seating capacities typically equal or exceed 60 children on average (roughly equivalent to 40 adults). If transit vehicle evacuees are two thirds adults and one third children, then the number of “adult seats” taken by 30 persons is 20 + (2/3 x10) = 27. On this basis, the average load factor anticipated is (27/40) x 100 = 68 percent. Thus, if the actual demand for service exceeds the estimates of Table 8-1 by 50 percent, the demand for service can still be accommodated by the available bus seating capacity.

$$\left[20+\left(\frac{2}{3}\times 10\right)\right]\div 40\times 1.5=1.00$$

Table 8-1 indicates that transportation must be provided for 360 people. Therefore, a total of **12 bus runs** are required to transport this population to EAC. While only 12 buses are needed from a capacity perspective, the county emergency plans collectively identify 25 different bus routes used to evacuate transit-dependent persons. This study will assume one bus is dispatched on each route resulting in a total of 25 buses to service the transit-dependent population in the NAPS EPZ.

To illustrate this estimation procedure, we calculate the number of persons, P, requiring public transit or ride-share, and the number of buses, B, required for the NAPS EPZ:

$$P = No.of\ HH\ \times \sum_{i=0}^{n} \{(\%\ HH\ with\ i\ vehicles) \times [(Average\ HH\ Size) - i]\} \times A^i C^i$$

Where,

A = Percent of households with commuters

C = Percent of households who will not await the return of a commuter

$$P = 9{,}806 \times [0.022 \times 1.50 + 0.154 \times (1.85 - 1) \times 0.59 \times 0.39 + 0.411 \times (2.47 - 2) \times (0.59 \times 0.39)^2] = 9{,}806 \times 0.0733 = 719$$

$$B = (0.5 \times P) \div 30 = 12$$

These calculations are explained as follows:

- All members (1.50 avg.) of households (HH) with no vehicles (2.2%) will evacuate by public transit or ride-share. The term 9,806 (number of households) x 0.022 x 1.50 accounts for these people.
- The members of HH with 1 vehicle away (15.4%), who are at home, equal (1.85-1). The number of HH where the commuter will not return home is equal to (9,806 x 0.154 x 0.59 x 0.39), as 59% of EPZ households have a commuter, 39% of which would not return home in the event of an emergency. The number of persons who will evacuate by public transit or ride-share is equal to the product of these two terms.
- The members of HH with 2 vehicles that are away (41.1%), who are at home, equal (2.47 – 2). The number of HH where neither commuter will return home is equal to 9,806 x 0.411 x $(0.59 \times 0.39)^2$. The number of persons who will evacuate by public transit or ride-share is equal to the product of these two terms (the last term is squared to represent the probability that neither commuter will return).
- Households with 3 or more vehicles are assumed to have no need for transit vehicles.
- The total number of persons requiring public transit is the sum of such people in HH with no vehicles, or with 1 or 2 vehicles that are away from home.

The estimate of transit-dependent population in Table 8-1 far exceeds the number of registered transit-dependent persons in the EPZ as provided by the counties (discussed below in Section 8.5). This is consistent with the findings of NUREG/CR-6953, Volume 2, in that a large majority of the transit-dependent population within the EPZs of U.S. nuclear plants does not register with their local emergency response agency.

8.2 School Population – Transit Demand

Table 8-2 presents the school population and transportation requirements for the direct evacuation of all schools within the EPZ for the 2011-2012 school year. All schools in the NAPS EPZ are located in either Spotsylvania or Louisa County. Spotsylvania County student enrollment was provided by the local county emergency management agency and Louisa County student enrollment was obtained from a Virginia State website provided by VDEM. The column in Table 8-2 entitled "Buses Required" specifies the number of buses required for each school under the following set of assumptions and estimates:

- No students will be picked up by their parents prior to the arrival of the buses.
- While many high school students commute to school using private automobiles (as discussed in Section 2.4 of NUREG/CR-7002), the estimate of buses required for school evacuation do not consider the use of these private vehicles.
- Bus capacity, expressed in students per bus, is set to 70 for primary schools and 50 for middle and high schools.
- Those staff members who do not accompany the students will evacuate in their private vehicles.
- No allowance is made for student absenteeism, typically 3 percent daily.

Louisa County emergency management agency indicated that Jouett Elementary School, which is located beyond 10 miles from the NAPS, will shelter-in-place. Therefore, 0 buses are required to evacuate this facility (see Table 8-2).

It is recommended that the counties in the EPZ introduce procedures whereby the schools are contacted prior to the dispatch of buses from the depot, to ascertain the current estimate of students to be evacuated. In this way, the number of buses dispatched to the schools will reflect the actual number needed. The need for buses would be reduced by any high school students who have evacuated using private automobiles (if permitted by school authorities). Those buses originally allocated to evacuate schoolchildren that are not needed due to children being picked up by their parents, can be gainfully assigned to service other facilities or those persons who do not have access to private vehicles or to ride-sharing.

Table 8-3 presents a list of the EAC for each evacuating school in the EPZ. Students will be transported to these centers where they will be subsequently retrieved by their respective families.

8.3 Medical Facility Demand

Table 8-4 presents the census for the one medical facility in the EPZ. 23 people have been identified as living in, or being treated in, this facility. The current census for this facility was obtained by making a phone call to the facility. The data includes the number of ambulatory and wheelchair-bound patients at the facility.

The transportation requirements for the medical facility population are also presented in Table 8-4. The number of wheelchair van runs is determined by assuming that 4 patients can be accommodated per wheelchair van trip and the number of bus runs estimated assumes 30 ambulatory patients per trip.

8.4 Evacuation Time Estimates for Transit Dependent People

EPZ bus resources are assigned to evacuating schoolchildren (if school is in session at the time of the ATE) as the first priority in the event of an emergency. In the event that the allocation of buses dispatched from the depots to the various facilities and to the bus routes is somewhat "inefficient", or if there is a shortfall of available drivers, then there may be a need for some buses to return to the EPZ from the EAC after completing their first evacuation trip, to complete a "second wave" of providing transport service to evacuees. For this reason, the ETE for the transit-dependent population will be calculated for both a one wave transit evacuation and for two waves. Of course, if the impacted Evacuation Region is other than R03 (the entire EPZ), then there will likely be ample transit resources relative to demand in the impacted Region and this discussion of a second wave would likely not apply.

When school evacuation needs are satisfied, subsequent assignments of buses to service the transit-dependent population should be sensitive to their mobilization time. Clearly, the buses should be dispatched after people have completed their mobilization activities and are in a position to board the buses when they arrive at the pick-up points.

Evacuation Time Estimates for transit trips were developed using both good weather and adverse weather conditions. Figure 8-1 presents the chronology of events relevant to transit operations. The elapsed time for each activity will now be discussed with reference to Figure 8-1.

Activity: Mobilize Drivers (A→B→C)

Mobilization is the elapsed time from the Advisory to Evacuate until the time the buses arrive at the facility to be evacuated. It is assumed that for a rapidly escalating radiological emergency with no observable indication before the fact, drivers would likely require 90 minutes to be contacted, to travel to the depot, be briefed, and to travel to the transit-dependent facilities. Mobilization time is slightly longer in adverse weather – 100 minutes when raining, 110 minutes when snowing.

Activity: Board Passengers (C→D)

Based on discussions with offsite agencies, a loading time of 15 minutes (20 minutes for rain and 25 minutes for snow) for school buses is used.

For multiple stops along a pick-up route (transit-dependent bus routes) estimation of travel time must allow for the delay associated with stopping and starting at each pick-up point. The time, t, required for a bus to decelerate at a rate, "a", expressed in ft/sec/sec, from a speed, "v", expressed in ft/sec, to a stop, is t = v/a. Assuming the same acceleration rate and final speed following the stop yields a total time, T, to service boarding passengers:

$$T = t + B + t = B + 2t = B + \frac{2v}{a},$$

Where B = Dwell time to service passengers. The total distance, "s" in feet, travelled during the deceleration and acceleration activities is: $s = v^2/a$. If the bus had not stopped to service passengers, but had continued to travel at speed, v, then its travel time over the distance, s, would be: s/v = v/a. Then the total delay (i.e. pickup time, P) to service passengers is:

$$P = T - \frac{v}{a} = B + \frac{v}{a}$$

Assigning reasonable estimates:

- B = 50 seconds: a generous value for a single passenger, carrying personal items, to board per stop
- v = 25 mph = 37 ft/sec
- a = 4 ft/sec/sec, a moderate average rate

Then, P ≈ 1 minute per stop. Allowing 30 minutes pick-up time per bus run implies 30 stops per run, for good weather. It is assumed that bus acceleration and speed will be less in rain; total loading time is 40 minutes per bus in rain, 50 minutes in snow.

Activity: Travel to EPZ Boundary (D→E)

School Evacuation

Transportation resources available were provided by the EPZ county emergency management agencies and are summarized in Table 8-5. Also included in the table are the number of each type of transportation vehicle needed to evacuate schools, medical facilities, transit-dependent population and homebound special needs (discussed below in Section 8.5). These numbers indicate there are sufficient resources available to evacuate everyone in a single wave, if transportation resources are shared by the counties. While Louisa County has sufficient resources to evacuate each of their schools in a single wave, Spotsylvania County does not, and would require a second wave to evacuate all schoolchildren if no other resources could be made available.

The buses servicing the schools are ready to begin their evacuation trips at 105 minutes after the advisory to evacuate – 90 minutes mobilization time plus 15 minutes loading time – in good weather. The UNITES software discussed in Section 1.3 was used to define bus routes along the most likely path from a school being evacuated to the EPZ boundary, traveling toward the appropriate school EAC. This is done in UNITES by interactively selecting the series of nodes from the school to the EPZ boundary. Each bus route is given an identification number and is written to the DYNEV II input stream. DYNEV computes the route length and outputs the average speed for each 5 minute interval, for each bus route. The specified bus routes are documented in Table 8-6 (refer to the maps of the link-node analysis network in Appendix K for node locations). Data provided by DYNEV during the appropriate timeframe depending on the mobilization and loading times (i.e., 100 to 105 minutes after the advisory to evacuate for good weather) were used to compute the average speed for each route, as follows:

$$Average\ Speed\ \left(\frac{mi.}{hr}\right) = \left[\frac{\sum_{i=1}^{n} length\ of\ link\ i\ (mi)}{\sum_{i=1}^{n}\left\{Delay\ on\ link\ i\ (min.) + \frac{length\ of\ link\ i\ (mi.)}{current\ speed\ on\ link\ i\ \left(\frac{mi.}{hr.}\right)} \times \frac{60\ min.}{1\ hr.}\right\}}\right] \times \frac{60\ min.}{1\ hr.}$$

The average speed computed (using this methodology) for the buses servicing each of the schools in the EPZ is shown in Table 8-7 through Table 8-9 for school evacuation, and in Table 8-11 through Table 8-13 for the transit vehicles evacuating transit-dependent persons, which are discussed later. The travel time to the EPZ boundary was computed for each bus using the computed average speed and the distance to the EPZ boundary along the most likely route out of the EPZ. The travel time from the EPZ boundary to the EAC was computed assuming an average speed of 45 mph, 41 mph, and 36 mph for good weather, rain and snow, respectively. Speeds were reduced in Table 8-7 through Table 8-9 and Table 8-14 through Table 8-17 to 45 mph (41 mph for rain – 10% decrease – and 36 mph for snow – 20% decrease) for those calculated bus speeds which exceed 45 mph, as the school bus speed limit is 45 mph for roadways in Virginia where the maximum posted speed limit is 55 mph.

Table 8-7 (good weather), Table 8-8 (rain) and Table 8-9 (snow) present the following evacuation time estimates (rounded up to the nearest 5 minutes) for schools in the EPZ: (1) The elapsed time from the Advisory to Evacuate until the bus exits the EPZ; and (2) The elapsed time until the bus reaches the EAC. The evacuation time out of the EPZ can be computed as the sum of times associated with Activities A→B→C, C→D, and D→E (For example: 90 min + 15 + 5 = 1:50 for Post Oak Middle School, with good weather). The evacuation time to the EAC is determined by adding the time associated with Activity E→F (discussed below), to this EPZ evacuation time.

Evacuation of Transit-Dependent Population

The buses dispatched from the depots to service the transit-dependent evacuees will be scheduled so that they arrive at their respective routes after their passengers have completed their mobilization. As shown in Figure 5-4 (Residents with no Commuters), 90 percent of the evacuees will complete their mobilization when the buses will begin their routes, approximately 105 minutes after the Advisory to Evacuate.

Those buses servicing the transit-dependent evacuees will first travel along their pick-up routes, then proceed out of the EPZ to their respective EAC. Transit-dependent bus routes are defined in each of the counties Radiological Emergency Response Plan (RERP). Spotsylvania County has 10 bus routes that are shown graphically in Figure 8-2. Louisa County has 10 bus routes that are shown graphically in Figure 8-3. Hanover and Orange County have 2 bus routes each and Caroline County has 1 bus route, all of which are shown graphically in Figure 8-4. Details of the routes servicing the EPZ are described in Table 8-10. As discussed in Section 8.1, this study assumes 25 buses are used to service the transit-dependent population within the EPZ. It is assumed, for good weather conditions, that buses can mobilize and begin picking up evacuees within 105 minutes (i.e. when 90 percent of the residents without commuters are ready to begin their trip). Longer mobilization times of 115 minutes and 125 minutes are used for rain and snow, respectively.

As previously discussed, a pickup time of 30 minutes (good weather) is estimated for 30 individual stops to pick up passengers, with an average of one minute of delay associated with each stop. Longer pickup times of 40 minutes and 50 minutes are used for rain and snow, respectively.

The travel distance along the respective pick-up routes within the EPZ is estimated using GIS software. Bus travel times within the EPZ are computed using average speeds computed by DYNEV, using the aforementioned methodology that was used for school evacuation.

Table 8-11 through Table 8-13 present the transit-dependent population evacuation time estimates for each bus route calculated using the above procedures for good weather, rain and snow, respectively.

For example, the ETE for the Bus Route 1 – Spotsylvania County 1 - is computed as 105 + 17 + 30 = 2:35 for good weather (rounded up to nearest 5 minutes). Here, 17 minutes is the time to travel 12.6 miles at 45 mph, the average speed output by the model for this route starting at 105 minutes. The ETE for a second wave (discussed below) is presented in the event there is a shortfall of available buses or bus drivers, as previously discussed.

<u>Activity: Travel to Evacuation Assembly Centers (E→F)</u>

The distances from the EPZ boundary to the EAC are measured using GIS software along the most likely route from the EPZ exit point to the EAC. The EAC are mapped in Figure 10-1. For a one-wave evacuation, this travel time outside the EPZ does not contribute to the ETE. For a two-wave evacuation, the ETE for buses must be considered separately, since it could exceed the ETE for the general population. Assumed bus speeds of 45 mph, 41 mph, and 36 mph for good weather, rain, and snow, respectively, will be applied for this activity for buses servicing the transit-dependent population.

<u>Activity: Passengers Leave Bus (F→G)</u>

A bus can empty within 5 minutes. The driver takes a 10 minute break.

<u>Activity: Bus Returns to Route for Second Wave Evacuation (G→C)</u>

The buses assigned to return to the EPZ to perform a "second wave" evacuation of transit-dependent evacuees will be those that have already evacuated transit-dependent people who mobilized more quickly. The first wave of transit-dependent people depart the bus, and the bus then returns to the EPZ, travels to its route and proceeds to pick up more transit-dependent evacuees along the route. The travel time back to the EPZ is equal to the travel time to the EAC.

The second-wave ETE for Bus Route 1 is computed as follows for good weather:

- Bus arrives at EAC at 2:46 in good weather (2:35 to exit EPZ + 11 minute travel time to EAC).
- Bus discharges passengers (5 minutes) and driver takes a 10-minute rest: 15 minutes.
- Bus returns to EPZ, drives to the start of the route and completes second route: 11 minutes (equal to travel time to EAC) + 13 minutes (equal to travel time to start of route, i.e., 10 miles[1] @ 45 mph) + 17 minutes (equal to travel time for second route, i.e., 12.6 miles @ 45 mph) = 41 minutes
- Bus completes pick-ups along route: 30 minutes.
- Bus exits EPZ at time 2:35 + 0:11 + 0:15 + 0:41 + 0:30 = 4:15 (rounded up to nearest 5 minutes) after the Advisory to Evacuate.

Table 8-5 indicates that there are enough buses available to evacuate the entire school population within the EPZ, if transportation resources are shared by the counties. However, if for any reason transportation resources could not be shared, then Spotsylvania County would require a second-wave evacuation for two of their schools in order to transport all schoolchildren out of the EPZ. A second-wave ETE example is computed as follows for Post Oak Middle School in good weather:

- School buses arrive at the EAC at 2:01 (1:50 to exit the EPZ + 11 minute travel time) in good weather (see Table 8-7).
- Bus discharges passengers (5 minutes) and driver takes a 10-minute rest: 15 minutes.
- Bus returns to EPZ and drives back to the school: 11 minutes (equal to travel time to EAC for good weather - 8.3 miles @ 45 mph) + 4 minutes (equal to travel time to start of route - 3.4 miles @ 45 mph) = 16 minutes. 45 mph is the assumed inbound speed for travel from the EAC back to the school.
- Loading Time: 15 minutes.
- Travel to EPZ Boundary: 5 minutes (3.3 miles @ 44.5 mph). 44.5 mph is the average speed along the route from the school at 2 hours and 50 minutes.

ETE: 2:01 + 0:15 + 0:16 + 0:15 + 0:05 = 2:55 (rounded up to nearest 5 minutes) after the Advisory to Evacuate. Therefore, a second wave evacuation would require an additional 1 hour and 10 minutes relative to a single wave evacuation. As shown in Table 8-5, Louisa County has excess transportation resources. Mutual aid agreements with neighboring counties and assistance from the state could be used to address the shortfall in bus resources.

[1] Some transit-dependent bus routes have lengths in excess of 10 miles, as the buses circulate the EPZ to pick up individuals. It was conservatively assumed that buses could take a more direct path of travel from the EPZ boundary to the start of route - a maximum distance of 10 miles.

The ETE for the completion of the second wave for all transit-dependent bus routes are provided in Table 8-11 through Table 8-13. The average ETE for a two-wave evacuation of transit-dependent people exceeds the ETE for the general population at the 90th percentile.

The relocation of transit-dependent evacuees from the EAC to congregate care centers, if the counties decide to do so, is not considered in this study.

Evacuation of Medical Facilities

The bus operations for this group are similar to those for school evacuation except:

- Buses are assigned on the basis of 30 patients to allow for staff to accompany the patients.
- The passenger loading time will be longer at approximately one minute per patient to account for the time to move patients from inside the facility to the vehicles.

Table 8-4 indicates that 1 bus run and 1 wheelchair van run are needed to service the one medical facility in the EPZ. According to Table 8-5, the counties can collectively provide 235 buses, 13 wheelchair accessible vans and 27 ambulances. Thus, there are sufficient resources to evacuate the ambulatory and wheelchair bound persons from this JABA Adult Daycare facility in a single wave.

As is done for the schools, it is estimated that mobilization time averages 90 minutes. Specially trained medical support staff (working their regular shift) will be on site to assist in the evacuation of patients. Additional staff (if needed) could be mobilized over this same 90 minute timeframe.

Table 8-14 through Table 8-16 summarize the ETE for this medical facility for good weather, rain, and snow. . Average speeds output by the model for Scenario 6 (Scenario 7 for rain and Scenario 8 for snow) Region 3, capped at 45 mph (41 mph for rain and 36 mph for snow), are used to compute travel time to EPZ boundary. The travel time to the EPZ boundary is computed by dividing the distance of 1.7 miles by the average travel speed. The ETE is the sum of the mobilization time, total passenger loading time, and travel time out of the EPZ. All ETE are rounded to the nearest 5 minutes. The calculation of ETE for the JABA Adult Daycare with 21 ambulatory residents during good weather is:

ETE: 90 + 21 x 1 + 2 = 113 min. or 1:55 rounded to the nearest 5 minutes.

It is assumed that medical facility population is directly evacuated to appropriate host medical facilities. Relocation of this population to permanent facilities and/or passing through the EAC before arriving at the host facility is not considered in this analysis.

8.5 Special Needs Population

Based on data provided by the counties, there are an estimated 185 homebound special needs people within the Louisa County portion of the EPZ and 6 people within the Caroline County portion of the EPZ who require transportation assistance to evacuate. Spotsylvania County indicated that they do not keep a list of transit-dependent and special needs persons; Orange County does not have any persons requiring transportation assistance and no special needs population information was available for Hanover County. Caroline County indicated that they have 5 ambulatory and 1 wheelchair-bound individual. Details on the number of ambulatory, wheelchair-bound and bedridden people were not available for Louisa County. It is assumed that the percentage of ambulatory (90%) and wheelchair-bound (10%) are similar to the average percentages between Caroline County and the one medical facility in Louisa County (JABA Adult Daycare). This results in 166 ambulatory persons and 19 wheelchair-bound persons for Louisa County, and a total of 171 ambulatory and 20 wheelchair-bound persons for the entire EPZ.

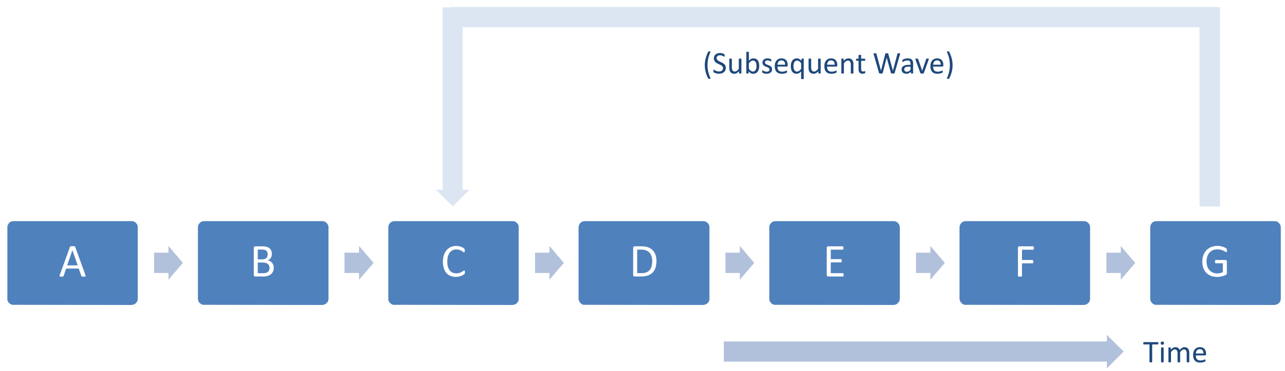
ETE for Homebound Special Needs Persons

Table 8-17 summarizes the ETE for homebound special needs people. The table is categorized by type of vehicle required and then broken down by weather condition. The table takes into consideration the deployment of multiple vehicles to reduce the number of stops per vehicle. It is conservatively assumed that ambulatory and wheelchair bound special needs households are spaced 3 miles apart and bedridden households are spaced 5 miles apart. Van and bus speeds approximate 20 mph between households and ambulance speeds approximate 30 mph in good weather (10% slower in rain, 20% slower in snow). Mobilization times of 90 minutes were used (100 minutes for rain, and 110 minutes for snow). The last HH is assumed to be 5 miles from the EPZ boundary, and the network-wide average speed, capped at 45 mph (41 mph for rain and 36 mph for snow), after the last pickup is used to compute travel time. ETE is computed by summing mobilization time, loading time at first household, travel to subsequent households, loading time at subsequent households, and travel time to EPZ boundary. All ETE are rounded to the nearest 5 minutes.

For example, assuming no more than one special needs person per HH implies that 171 ambulatory households need to be serviced. While only 6 buses are needed from a capacity perspective, if 25 buses are deployed to service these special needs HH, then each would require about 7 stops. The following outlines the ETE calculations:

1. Assume 25 buses are deployed, each with about 7 stops, to service a total of 171 HH.
2. The ETE is calculated as follows:
    a. Buses arrive at the first pickup location: 90 minutes
    b. Load HH members at first pickup: 5 minutes
    c. Travel to subsequent pickup locations: 6 @ 9 minutes = 54 minutes
    d. Load HH members at subsequent pickup locations: 6 @ 5 minutes = 30 minutes
    e. Travel to EPZ boundary: 7 minutes (5 miles @ 45 mph).

ETE: 90 + 5 + 54 + 30 + 7 = 3:10 rounded up to the nearest 5 minutes



Event	
A	Advisory to Evacuate
B	Bus Dispatched from Depot
C	Bus Arrives at Facility/Pick-up Route
D	Bus Departs for Evacuation Assembly Center
E	Bus Exits Region
F	Bus Arrives at Evacuation Assembly Center
G	Bus Available for “Second Wave” Evacuation Service
Activity	
A→B	Driver Mobilization
B→C	Travel to Facility or to Pick-up Route
C→D	Passengers Board the Bus
D→E	Bus Travels Towards Region Boundary
E→F	Bus Travels Towards Evacuation Assembly Center Outside the EPZ
F→G	Passengers Leave Bus; Driver Takes a Break

Figure 8-1. Chronology of Transit Evacuation Operations

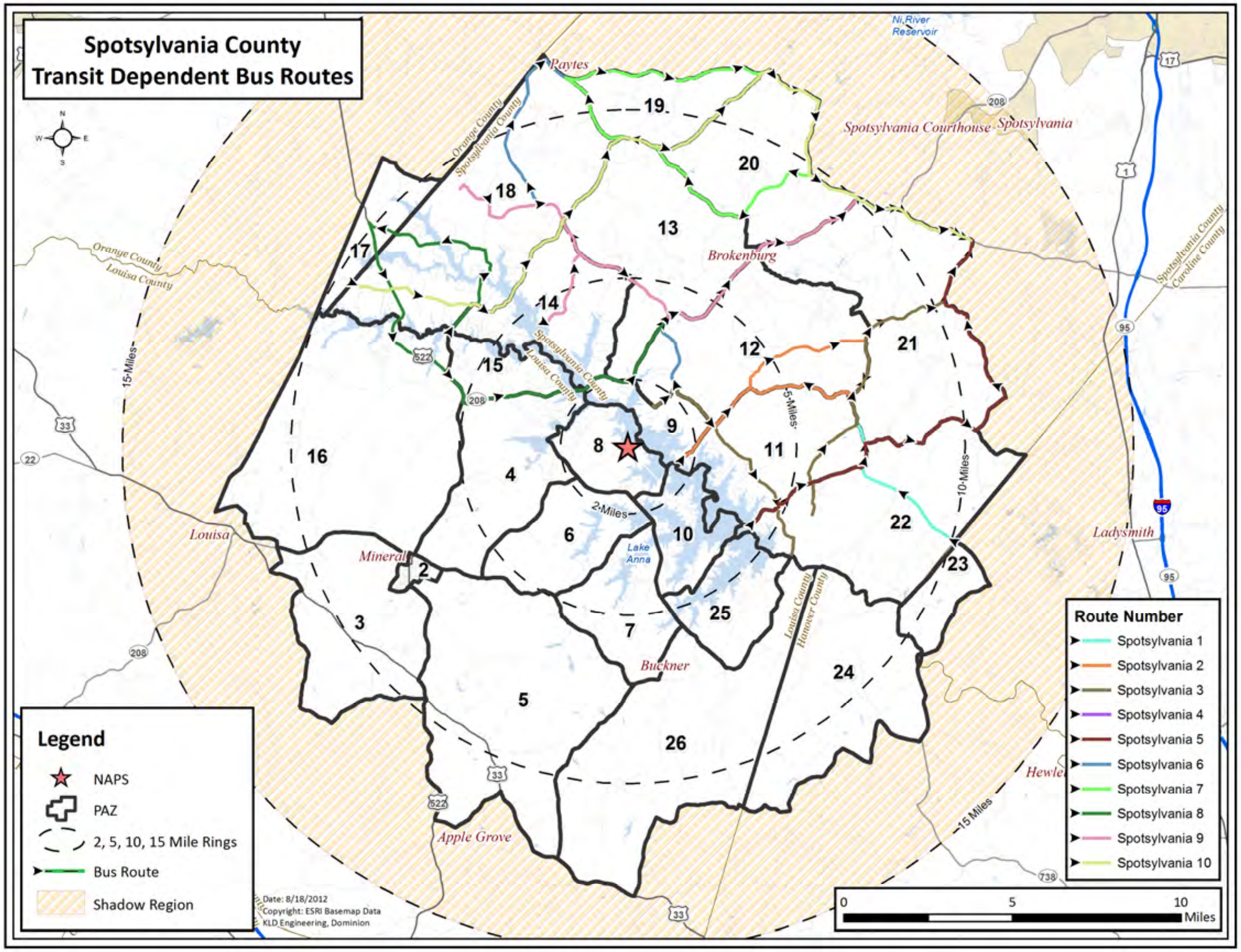


Figure 8-2. Transit-Dependent Bus Routes – Spotsylvania County

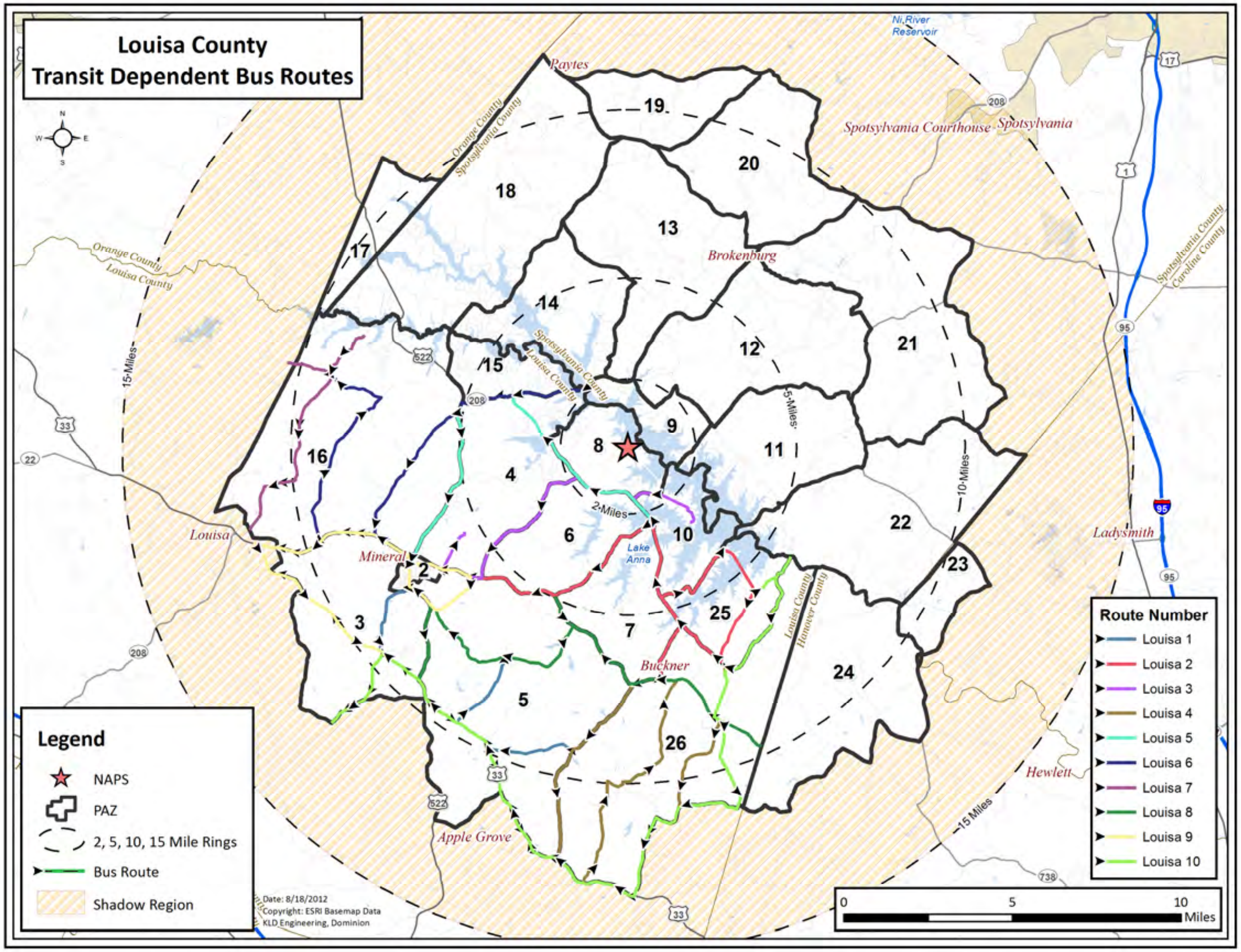


Figure 8-3. Transit-Dependent Bus Routes – Louisa County

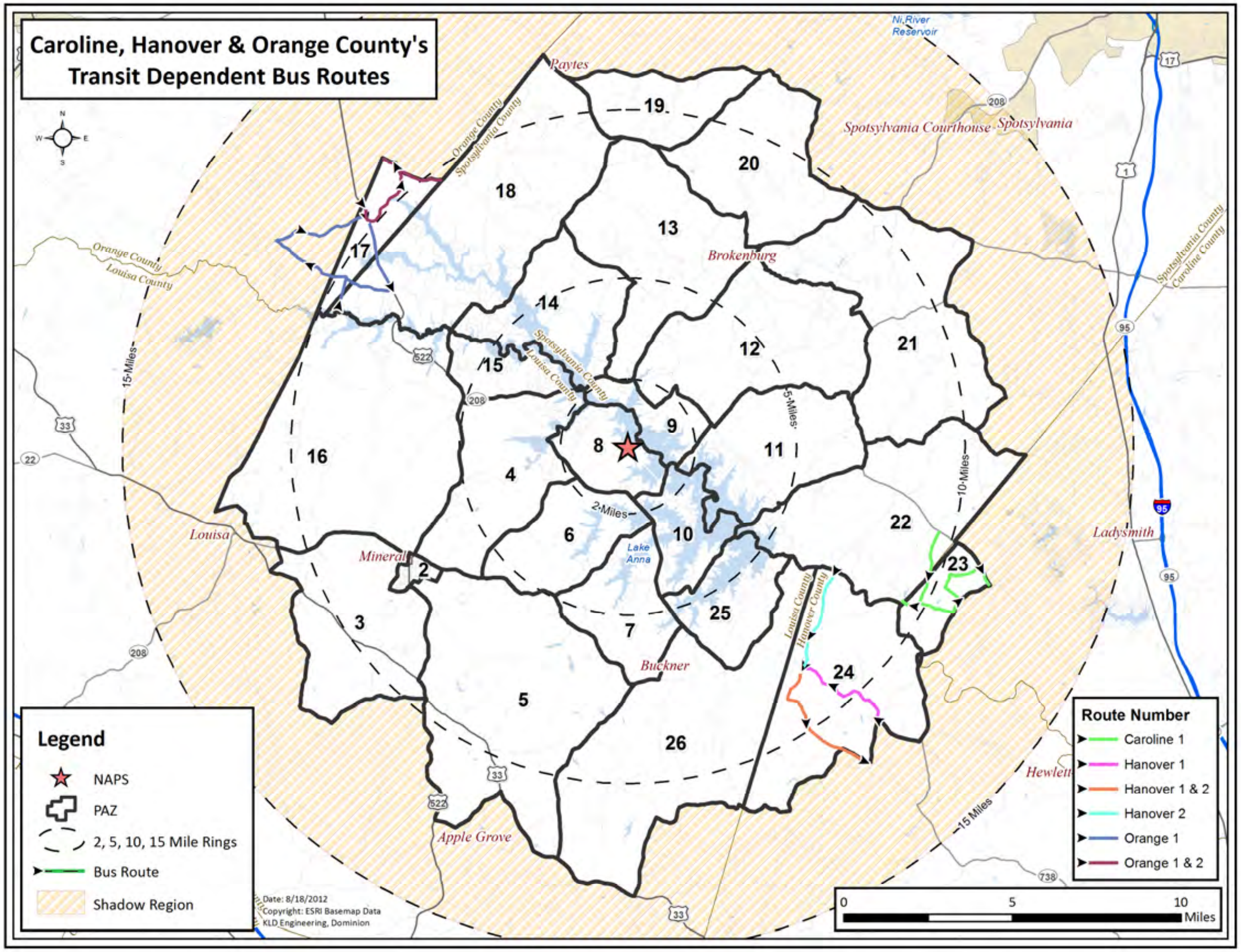


Figure 8-4. Transit-Dependent Bus Routes – Caroline, Hanover, Orange County

Table 8-1. Transit-Dependent Population Estimates

2010 EPZ Population	Survey Average HH Size with Indicated No. of Vehicles			Estimated No. of Households	Survey Percent HH with Indicated No. of Vehicles			Survey Percent HH with Commuters	Survey Percent HH with Non-Returning Commuters	Total People Requiring Transport	Estimated Ridesharing Percentage	People Requiring Public Transit	Percent Population Requiring Public Transit
	0	1	2		0	1	2						
25,202	1.50	1.85	2.47	9,806	2.2%	15.4%	41.1%	59%	39%	719	50%	360	1.4%

Table 8-2. School Population Demand Estimates

PAZ	School Name	Enrollment	Buses Required
2	Mineral Christian Preschool	60	1
3	Thomas Jefferson Elementary School	545	8
3	Louisa County High School	1,392	28
3	Louisa County Middle School	1,073	22
5	Jouett Elementary School[1]	597	0
12	Livingston Elementary School	444	7
21	Berkeley Elementary School	326	5
21	Post Oak Middle School	752	16
21	Spotsylvania High School	1,118	23
21	Spotsylvania High School - Governor's School	120	3
	TOTAL:	**6,427**	**113**

[1] School will shelter-in-place

Table 8-3. Evacuation Assembly Centers

School	Evacuation Assembly Center (EAC)
Livingston Elementary School	Courtland High School
Post Oak Middle School	Courtland High School
Berkeley Elementary School	Massaponax High School
Spotsylvania High School	Massaponax High School
Spotsylvania High School - Governor's School	Massaponax High School
Louisa County High School	Moss-Nuckols Elementary School
Louisa County Middle School	Moss-Nuckols Elementary School
Mineral Christian Preschool	Moss-Nuckols Elementary School
Thomas Jefferson Elementary School	Moss-Nuckols Elementary School
Jouett Elementary School	Shelter-in-Place

Table 8-4. Medical Facility Transit Demand

PAZ	Facility Name	Municipality	Cap-acity	Current Census	Ambu-latory	Wheel-chair Bound	Bed-ridden	Bus Runs	Wheel-chair Van Runs	Ambulance
LOUISA COUNTY MEDICAL FACILITIES										
3	JABA Adult Daycare	Louisa	N/A	23	21	2	0	1	1	0
		Louisa County Subtotal:	***-***	***23***	***21***	***2***	***0***	***1***	***1***	***0***
		TOTAL:	**-**	**23**	**21**	**2**	**0**	**1**	**1**	**0**

Table 8-5. Summary of Transportation Resources

Transportation Resource	Buses	Vans	Wheelchair Buses	Wheelchair Vans	Ambulances
Resources Available					
Louisa County	107	-	-	7	14
Caroline County	81	-	-	6	13
Berkeley Elementary School	9	-	-	-	-
Livingston Elementary School	10	-	-	-	-
Post Oak Middle School	12	-	-	-	-
Spotsylvania High School	15	-	-	-	-
Mineral Christian Preschool	1	-	-	-	-
TOTAL:	**235**	**0**	**0**	**13**	**27**
Resources Needed					
Schools (Table 8-2):	113	-	-	-	-
Medical Facilities (Table 8-4):	1	-	-	1	-
Transit-Dependent Population (Table 8-10):	25	-	-	-	-
Homebound Special Needs (Section 8.5):	6	-	-	5	-
TOTAL TRANSPORTATION NEEDS:	**145**	**0**	**0**	**6**	**0**

Notes: - Spotsylvania County has a combined 46 buses, however, need a total of 54 buses to evacuate all students
- Post Oak Middle School has 12 buses and need 16 buses to evacuate all schoolchildren
- Spotsylvania High School has 15 buses and need 26 buses to evacuate the High School and Governor's School
- Louisa County needs 58 buses to evacuate all schoolchildren

Table 8-6. Bus Route Descriptions

Bus Route Number	Description	Nodes Traversed from Route Start to EPZ Boundary
1	Spotsylvania County 1 - Transit Route	108, 406, 107, 390, 389, 388, 106, 588, 383, 587, 586, 585, 584, 583, 582, 387, 386, 105, 10
2	Spotsylvania County 2 - Transit Route	399, 400, 490, 388, 106, 588, 383, 587, 586, 585, 584, 583, 582, 387, 386, 105, 10
3	Spotsylvania County 3 - Transit Route	153, 399, 398, 555, 397, 392, 393, 394, 619, 395, 396, 108, 406, 107, 390, 389, 388, 106, 588, 383, 587, 586, 585, 584, 583, 582, 387, 386, 105, 10
4	Spotsylvania County 4 - Transit Route	203, 5, 283, 160, 6, 276, 171, 7, 378, 377, 174, 8, 497, 9, 10
5	Spotsylvania County 5 - Transit Route	394, 619, 395, 396, 108, 406, 107, 390, 389, 388, 106, 588, 383, 587, 586, 585, 584, 583, 582, 387, 386, 105, 10
6	Spotsylvania County 6 - Transit Route	158, 159, 556, 557, 160, 6, 144, 622, 141, 140, 71, 559, 74, 79, 91, 96, 99, 100, 21
7	Spotsylvania County 7 - Transit Route	23, 489, 104, 103, 22, 192, 458, 21
9	Spotsylvania County 9 - Transit Route	72, 558, 71, 140, 141, 622, 144, 6, 276, 171, 7, 378, 377, 174, 8, 497, 9, 10
10	Spotsylvania County 10 - Transit Route	136, 130, 125, 74, 486, 101, 102, 103, 22, 192, 458, 21
11	Louisa County 1 - Transit Route	163, 80, 313
12	Louisa County 2 - Transit Route	37, 604, 60, 248, 271, 272, 273, 59, 600, 274, 58, 281, 601, 602, 434, 57, 603, 56, 48, 335, 305, 517, 63, 64, 312, 342, 182, 519
13	Louisa County 3 - Transit Route	36, 433, 428, 429, 430, 431, 432, 434, 57, 603, 56, 48, 335, 305, 517, 63, 64, 312, 342, 182, 519
14	Louisa County 4 - Transit Route	81, 278, 92, 93, 539
15	Louisa County 5 - Transit Route	36, 199, 607, 321, 4, 347, 348, 511, 3, 510, 299, 345, 346, 344, 343, 46, 298, 47, 513, 297, 48, 335, 305, 517, 63, 64, 312, 342, 182, 519
16	Louisa County 6 - Transit Route	447, 228, 227, 525, 524, 522, 222, 521, 520, 221, 220, 219
17	Louisa County 7 - Transit Route	510, 241, 447, 228, 227, 525, 524, 522, 222, 521, 520, 221, 220, 219
18	Louisa County 8 - Transit Route	81, 278, 92, 93, 539
19	Louisa County 9 - Transit Route	163, 165, 188, 81, 278, 92, 93, 539
20	Louisa County 10 - Transit Route	81, 278, 92, 93, 539
21	Orange County 1 - Transit Route	35, 14, 482, 239, 240

Bus Route Number	Description	Nodes Traversed from Route Start to EPZ Boundary
22	Orange County 2 - Transit Route	482, 239, 240
23	Hanover County 1 - Transit Route	438, 546, 547, 41
24	Hanover County 2 - Transit Route	154, 41, 439
25	Caroline County 1 - Transit Route	110, 111, 112
50	Thomas Jefferson Elementary School	163, 80, 313
51	Louisa County High School	516, 517, 63, 64, 312, 342, 182, 519
52	Louisa County Middle School	517, 63, 64, 312, 342, 182, 519
54	Livingston Elementary School	171, 7, 378, 377, 174, 8, 497, 9, 10
55	Post Oak Middle School	497, 9, 10
56	Berkeley Elementary School	582, 387, 386, 105, 10
57	Spotsylvania High School, Spotsylvania High School – Governor's School	581, 497, 9, 10
58	Mineral Christian Preschool	297, 48, 335, 305, 517, 63, 64, 312, 342, 182, 519
70	JABA Adult Daycare	518, 342, 182

Notes: - Transit route labels match counties RERP (from ESF #6, Mass Care Procedure)

- Jouett Elementary School not included since it shelters-in-place

Table 8-7. School Evacuation Time Estimates - Good Weather

School	Driver Mobilization Time (min)	Loading Time (min)	Dist. To EPZ Bdry (mi)	Average Speed (mph)	Travel Time to EPZ Bdry (min)	ETE (hr:min)	Dist. EPZ Bdry to EAC (mi.)	Travel Time from EPZ Bdry to EAC (min)	ETE to EAC (hr:min)
LOUISA COUNTY SCHOOLS									
Louisa County High School	90	15	3.7	45.0	5	**1:50**	8.3	11	**2:05**
Louisa County Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Mineral Christian Preschool	90	15	4.8	45.0	7	**1:55**	8.3	11	**2:10**
Thomas Jefferson Elementary School	90	15	1.5	45.0	3	**1:50**	8.6	11	**2:05**
SPOTSYLVANIA COUNTY SCHOOLS									
Berkeley Elementary School	90	15	2.1	44.7	3	**1:50**	8.0	11	**2:05**
Livingston Elementary School	90	15	9.1	45.0	13	**2:00**	8.3	11	**2:10**
Post Oak Middle School	90	15	3.4	45.0	5	**1:50**	8.3	11	**2:05**
Spotsylvania High School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
Spotsylvania High School - Governor's School	90	15	3.2	44.2	5	**1:50**	8.0	11	**2:05**
					Maximum for EPZ:	**2:00**		**Maximum:**	**2:10**
					Average for EPZ:	**1:55**		**Average:**	**2:10**

Table 8-8. School Evacuation Time Estimates - Rain

School	Driver Mobilization Time (min)	Loading Time (min)	Dist. To EPZ Bdry (mi)	Average Speed (mph)	Travel Time to EPZ Bdry (min)	ETE (hr:min)	Dist. EPZ Bdry to EAC (mi.)	Travel Time from EPZ Bdry to EAC (min)	ETE to EAC (hr:min)
LOUISA COUNTY SCHOOLS									
Louisa County High School	100	20	3.7	41.0	6	**2:10**	8.3	12	**2:25**
Louisa County Middle School	100	20	3.4	41.0	5	**2:05**	8.3	12	**2:20**
Mineral Christian Preschool	100	20	4.8	41.0	8	**2:10**	8.3	12	**2:25**
Thomas Jefferson Elementary School	100	20	1.5	41.0	3	**2:05**	8.6	13	**2:20**
SPOTSYLVANIA COUNTY SCHOOLS									
Berkeley Elementary School	100	20	2.1	40.4	4	**2:05**	8.0	12	**2:20**
Livingston Elementary School	100	20	9.1	41.0	14	**2:15**	8.3	12	**2:30**
Post Oak Middle School	100	20	3.4	40.3	6	**2:10**	8.3	12	**2:25**
Spotsylvania High School	100	20	3.2	39.0	5	**2:05**	8.0	12	**2:20**
Spotsylvania High School - Governor's School	100	20	3.2	39.0	5	**2:05**	8.0	12	**2:20**
					Maximum for EPZ:	**2:15**		**Maximum:**	**2:30**
					Average for EPZ:	**2:10**		**Average:**	**2:25**

Table 8-9. School Evacuation Time Estimates - Snow

School	Driver Mobilization Time (min)	Loading Time (min)	Dist. To EPZ Bdry (mi)	Average Speed (mph)	Travel Time to EPZ Bdry (min)	ETE (hr:min)	Dist. EPZ Bdry to EAC (mi.)	Travel Time from EPZ Bdry to H.S. (min)	ETE to EAC (hr:min)
LOUISA COUNTY SCHOOLS									
Louisa County High School	110	25	3.7	36.0	7	**2:25**	8.3	14	**2:40**
Louisa County Middle School	110	25	3.4	36.0	6	**2:25**	8.3	14	**2:40**
Mineral Christian Preschool	110	25	4.8	36.0	9	**2:25**	8.3	14	**2:40**
Thomas Jefferson Elementary School	110	25	1.5	36.0	3	**2:20**	8.6	14	**2:35**
SPOTSYLVANIA COUNTY SCHOOLS									
Berkeley Elementary School	110	25	2.1	36.0	4	**2:20**	8.0	13	**2:35**
Livingston Elementary School	110	25	9.1	36.0	16	**2:35**	8.3	14	**2:50**
Post Oak Middle School	110	25	3.4	35.9	6	**2:25**	8.3	14	**2:40**
Spotsylvania High School	110	25	3.2	35.2	6	**2:25**	8.0	13	**2:40**
Spotsylvania High School - Governor's School	110	25	3.2	35.2	6	**2:25**	8.0	13	**2:40**
					Maximum for EPZ:	**2:35**		**Maximum:**	**2:50**
					Average for EPZ:	**2:25**		**Average:**	**2:40**

Table 8-10. Summary of Transit-Dependent Bus Routes

Route	No. of Buses	Route Description	Length (mi.)
1	1	Spotsylvania County 1 - pick up residents in PAZ 11, 12, 21, 22	12.6
2	1	Spotsylvania County 2 - pick up residents in PAZ 11, 12, 21	17.4
3	1	Spotsylvania County 3 - pick up residents in PAZ 9, 11, 12, 22	20.2
4	1	Spotsylvania County 4 - pick up residents in PAZ 9, 11, 12, 13, 20, 21	15.3
5	1	Spotsylvania County 5 - pick up residents in PAZ 11, 21, 22	13.0
6	1	Spotsylvania County 6 - pick up residents in PAZ 12, 13, 14, 18	25.5
7	1	Spotsylvania County 7 - pick up residents in PAZ 13, 18, 19	19.8
8	1	Spotsylvania County 8 - pick up residents in PAZ 14, 18	32.2
9	1	Spotsylvania County 9 - pick up residents in PAZ 13, 14, 18	22.8
10	1	Spotsylvania County 10 - pick up residents in PAZ 13, 14, 18, 20	26.3
11	1	Louisa County 1 - pick up residents in PAZ 3, 5	17.3
12	1	Louisa County 2 - pick up residents in PAZ 6, 7, 10, 25	27.6
13	1	Louisa County 3 - pick up residents in PAZ 4, 6, 8, 10	17.0
14	1	Louisa County 4 - pick up residents in PAZ 5, 7, 26	36.6
15	1	Louisa County 5 - pick up residents in PAZ 2, 4, 8, 10, 15, 16	17.5
16	1	Louisa County 6 - pick up residents in PAZ 4, 8, 15, 16	23.2
17	1	Louisa County 7 - pick up residents in PAZ 15, 16	9.5
18	1	Louisa County 8 - pick up residents in PAZ 3, 5, 7, 26	30.5
19	1	Louisa County 9 - pick up residents in PAZ 2, 3, 5, 16	18.5
20	1	Louisa County 10 - pick up residents in PAZ 3	29.2
21	1	Orange County 1 - pick up residents in PAZ 17	10.7
22	1	Orange County 2 - pick up residents in PAZ 17	5.1
23	1	Hanover County 1 - pick up residents in PAZ 24	7.7
24	1	Hanover County 2 - pick up residents in PAZ 24	8.0
25	1	Caroline County 1 - pick up residents in PAZ 23	7.2
Total:	**25**		

Notes: - Transit route names taken from counties RERP (from ESF #6, Mass Care Procedure)

Table 8-11. Transit-Dependent Evacuation Time Estimates - Good Weather

Route Number	Bus Number	One-Wave						Distance to EAC (miles)	Two-Wave					
		Mobilization (min)	Route Length (miles)	Speed (mph)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)		Travel Time to EAC (min)	Unload (min)	Driver Rest (min)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)
1	1	105	12.6	45.0	17	30	**2:35**	8.2	11	5	10	41	30	**4:15**
2	1	105	17.4	38.9	27	30	**2:45**	8.2	11	5	10	50	30	**4:35**
3	1	105	20.2	44.6	27	30	**2:45**	8.2	11	5	10	51	30	**4:35**
4	1	105	15.3	45.0	20	30	**2:35**	8.2	11	5	10	45	30	**4:20**
5	1	105	13.0	45.0	17	30	**2:35**	8.9	12	5	10	43	30	**4:15**
6	1	105	25.5	45.0	34	30	**2:50**	8.5	11	5	10	59	30	**4:50**
7	1	105	19.8	45.0	26	30	**2:45**	12.1	16	5	10	56	30	**4:45**
8	1	105	32.2	45.0	43	30	**3:00**	8.2	11	5	10	67	30	**5:05**
9	1	105	22.8	45.0	30	30	**2:45**	8.2	11	5	10	55	30	**4:40**
10	1	105	26.3	40.2	39	30	**2:55**	8.2	11	5	10	61	30	**4:55**
11	1	105	17.3	45.0	23	30	**2:40**	9.5	13	5	10	49	30	**4:30**
12	1	105	27.6	45.0	37	30	**2:55**	8.3	11	5	10	61	30	**4:55**
13	1	105	17.0	44.8	23	30	**2:40**	8.3	11	5	10	47	30	**4:25**
14	1	105	36.6	45.0	49	30	**3:05**	13.5	18	5	10	80	30	**5:30**
15	1	105	17.5	45.0	23	30	**2:40**	8.3	11	5	10	48	30	**4:25**
16	1	105	23.2	44.5	31	30	**2:50**	7.8	10	5	10	55	30	**4:45**
17	1	105	9.5	43.0	13	30	**2:30**	7.8	10	5	10	36	30	**4:05**
18	1	105	30.5	45.0	41	30	**3:00**	13.5	18	5	10	72	30	**5:15**
19	1	105	18.5	45.0	25	30	**2:40**	13.5	18	5	10	56	30	**4:40**
20	1	105	29.2	45.0	39	30	**2:55**	13.5	18	5	10	70	30	**5:10**
21	1	105	10.7	45.0	14	30	**2:30**	14.8	20	5	10	47	30	**4:25**
22	1	105	5.1	45.0	7	30	**2:25**	12.6	17	5	10	31	30	**4:00**
23	1	105	7.7	45.0	10	30	**2:25**	13.4	18	5	10	38	30	**4:10**
24	1	105	8.0	35.5	13	30	**2:30**	13.4	18	5	10	41	30	**4:15**
25	1	105	7.2	45.0	10	30	**2:25**	12.7	17	5	10	36	30	**4:05**
						Maximum ETE:	**3:05**						**Maximum ETE:**	**5:30**
						Average ETE:	**2:45**						**Average ETE:**	**4:35**

Table 8-12. Transit-Dependent Evacuation Time Estimates – Rain

Route Number	Bus Number	One-Wave						Distance to EAC (miles)	Two-Wave					
		Mobilization (min)	Route Length (miles)	Speed (mph)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)		Travel Time to EAC (min)	Unload (min)	Driver Rest (min)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)
1	1	115	12.6	41.0	18	40	**2:55**	8.2	12	5	10	44	40	**4:50**
2	1	115	17.4	36.2	29	40	**3:05**	8.2	12	5	10	53	40	**5:05**
3	1	115	20.2	41.0	30	40	**3:05**	8.2	12	5	10	55	40	**5:10**
4	1	115	15.3	41.0	22	40	**3:00**	8.2	12	5	10	48	40	**4:55**
5	1	115	13.0	41.0	19	40	**2:55**	8.9	13	5	10	45	40	**4:50**
6	1	115	25.5	41.0	37	40	**3:15**	8.5	12	5	10	63	40	**5:30**
7	1	115	19.8	41.0	29	40	**3:05**	12.1	18	5	10	60	40	**5:20**
8	1	115	32.2	41.0	47	40	**3:25**	8.2	12	5	10	72	40	**5:45**
9	1	115	22.8	41.0	33	40	**3:10**	8.2	12	5	10	59	40	**5:20**
10	1	115	26.3	37.2	42	40	**3:20**	8.2	12	5	10	67	40	**5:35**
11	1	115	17.3	41.0	25	40	**3:00**	9.5	14	5	10	52	40	**5:05**
12	1	115	27.6	40.9	40	40	**3:15**	8.3	12	5	10	66	40	**5:30**
13	1	115	17.0	40.8	25	40	**3:00**	8.3	12	5	10	50	40	**5:00**
14	1	115	36.6	41.0	54	40	**3:30**	13.5	20	5	10	87	40	**6:15**
15	1	115	17.5	41.0	26	40	**3:05**	8.3	12	5	10	51	40	**5:05**
16	1	115	23.2	40.1	35	40	**3:10**	7.8	11	5	10	59	40	**5:20**
17	1	115	9.5	38.6	15	40	**2:50**	7.8	11	5	10	39	40	**4:40**
18	1	115	30.5	41.0	45	40	**3:20**	13.5	20	5	10	78	40	**5:55**
19	1	115	18.5	41.0	27	40	**3:05**	13.5	20	5	10	60	40	**5:20**
20	1	115	29.2	41.0	43	40	**3:20**	13.5	20	5	10	76	40	**5:55**
21	1	115	10.7	41.0	16	40	**2:55**	14.8	22	5	10	51	40	**5:05**
22	1	115	5.1	41.0	8	40	**2:45**	12.6	18	5	10	33	40	**4:35**
23	1	115	7.7	41.0	11	40	**2:50**	13.4	20	5	10	41	40	**4:50**
24	1	115	8.0	33.1	14	40	**2:50**	13.4	20	5	10	44	40	**4:50**
25	1	115	7.2	41.0	11	40	**2:50**	12.7	19	5	10	39	40	**4:45**
						Maximum ETE:	**3:30**						**Maximum ETE:**	**6:15**
						Average ETE:	**3:05**						**Average ETE:**	**5:15**

Table 8-13. Transit Dependent Evacuation Time Estimates – Snow

		One-Wave							Two-Wave					
Route Number	Bus Number	Mobilization (min)	Route Length (miles)	Speed (mph)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)	Distance to EAC (miles)	Travel Time to EAC (min)	Unload (min)	Driver Rest (min)	Route Travel Time (min)	Pickup Time (min)	ETE (hr:min)
1	1	125	12.6	36.0	21	50	**3:20**	8.2	14	5	10	48	50	**5:30**
2	1	125	17.4	32.5	32	50	**3:30**	8.2	14	5	10	56	50	**5:45**
3	1	125	20.2	36.0	34	50	**3:30**	8.2	14	5	10	61	50	**5:50**
4	1	125	15.3	36.0	26	50	**3:25**	8.2	14	5	10	52	50	**5:40**
5	1	125	13.0	36.0	22	50	**3:20**	8.9	15	5	10	50	50	**5:30**
6	1	125	25.5	36.0	42	50	**3:40**	8.5	14	5	10	70	50	**6:10**
7	1	125	19.8	36.0	33	50	**3:30**	12.1	20	5	10	66	50	**6:05**
8	1	125	32.2	36.0	54	50	**3:50**	8.2	14	5	10	81	50	**6:30**
9	1	125	22.8	36.0	38	50	**3:35**	8.2	14	5	10	65	50	**6:00**
10	1	125	26.3	33.7	47	50	**3:45**	8.2	14	5	10	73	50	**6:20**
11	1	125	17.3	36.0	29	50	**3:25**	9.5	16	5	10	58	50	**5:45**
12	1	125	27.6	36.0	46	50	**3:45**	8.3	14	5	10	73	50	**6:20**
13	1	125	17.0	35.9	28	50	**3:25**	8.3	14	5	10	56	50	**5:40**
14	1	125	36.6	36.0	61	50	**4:00**	13.5	22	5	10	97	50	**7:05**
15	1	125	17.5	36.0	29	50	**3:25**	8.3	14	5	10	56	50	**5:40**
16	1	125	23.2	35.8	39	50	**3:35**	7.8	13	5	10	66	50	**6:00**
17	1	125	9.5	34.6	17	50	**3:15**	7.8	13	5	10	42	50	**5:15**
18	1	125	30.5	36.0	51	50	**3:50**	13.5	22	5	10	87	50	**6:45**
19	1	125	18.5	36.0	31	50	**3:30**	13.5	22	5	10	67	50	**6:05**
20	1	125	29.2	36.0	49	50	**3:45**	13.5	22	5	10	84	50	**6:40**
21	1	125	10.7	36.0	18	50	**3:15**	14.8	25	5	10	56	50	**5:45**
22	1	125	5.1	36.0	9	50	**3:05**	12.6	21	5	10	36	50	**5:10**
23	1	125	7.7	36.0	13	50	**3:10**	13.4	22	5	10	45	50	**5:25**
24	1	125	8.0	29.3	16	50	**3:15**	13.4	22	5	10	48	50	**5:35**
25	1	125	7.2	36.0	12	50	**3:10**	12.7	21	5	10	43	50	**5:20**
						Maximum ETE:	**4:00**						**Maximum ETE:**	**7:05**
						Average ETE:	**3:30**						**Average ETE:**	**5:55**

Table 8-14. Medical Facility Evacuation Time Estimates - Good Weather

Medical Facility	Patient	Mobilization (min)	Loading Rate (min per person)	People	Total Loading Time (min)	Dist. To EPZ Bdry (mi)	Travel Time to EPZ Boundary (min)	ETE (hr:min)
JABA Adult Daycare	Ambulatory	90	1	21	21	1.7	2	**1:55**
	Wheelchair bound	90	5	2	10	1.7	2	**1:45**
Maximum ETE:								**1:55**
Average ETE:								**1:50**

Table 8-15. Medical Facility Evacuation Time Estimates – Rain

Medical Facility	Patient	Mobilization (min)	Loading Rate (min per person)	People	Total Loading Time (min)	Dist. To EPZ Bdry (mi)	Travel Time to EPZ Boundary (min)	ETE (hr:min)
JABA Adult Daycare	Ambulatory	100	1	21	21	1.7	2	**2:05**
	Wheelchair bound	100	5	2	10	1.7	2	**1:55**
Maximum ETE:								**2:05**
Average ETE:								**2:00**

Table 8-16. Medical Facility Evacuation Time Estimates - Snow

Medical Facility	Patient	Mobilization (min)	Loading Rate (min per person)	People	Total Loading Time (min)	Dist. To EPZ Bdry (mi)	Travel Time to EPZ Boundary (min)	ETE (hr:min)
JABA Adult Daycare	Ambulatory	115	1	21	21	1.7	3	**2:20**
	Wheelchair bound	115	5	2	10	1.7	3	**2:10**
							Maximum ETE:	**2:20**
							Average ETE:	**2:15**

Table 8-17. Homebound Special Needs Population Evacuation Time Estimates

Vehicle Type	People Requiring Vehicle	Vehicles deployed	Stops	Weather Conditions	Mobilization Time (min)	Loading Time at 1st Stop (min)	Travel to Subsequent Stops (min)	Total Loading Time at Subsequent Stops (min)	Travel Time to EPZ Boundary (min)	ETE (hr:min)
Buses	171	25	7	Normal	90	5	54	30	7	**3:10**
				Rain	100		60		7	**3:25**
				Snow	110		66		8	**3:40**
Wheelchair Vans	20	8	3	Normal	90	5	18	10	7	**2:10**
				Rain	100		20		7	**2:25**
				Snow	110		22		8	**2:35**
									Maximum ETE:	**3:40**
									Average ETE:	**2:55**

9 TRAFFIC MANAGEMENT STRATEGY

This section discusses the suggested traffic control and management strategy that is designed to expedite the movement of evacuating traffic. The resources required to implement this strategy include:

- Personnel with the capabilities of performing the planned control functions of traffic guides (preferably, not necessarily, law enforcement officers).
- Traffic Control Devices to assist these personnel in the performance of their tasks. These devices should comply with the guidance of the Manual of Uniform Traffic Control Devices (MUTCD) published by the Federal Highway Administration (FHWA) of the U.S.D.O.T. All state and most county transportation agencies have access to the MUTCD, which is available on-line: http://mutcd.fhwa.dot.gov which provides access to the official PDF version.
- A plan that defines all locations, provides necessary details and is documented in a format that is readily understood by those assigned to perform traffic control.

The functions to be performed in the field are:

1. <u>Facilitate</u> evacuating traffic movements that safely expedite travel out of the EPZ.
2. <u>Discourage</u> traffic movements that move evacuating vehicles in a direction which takes them significantly closer to the power plant, or which interferes with the efficient flow of other evacuees.

The terms "facilitate" and "discourage" are employed rather than "enforce" and "prohibit" to indicate the need for flexibility in performing the traffic control function. There are always legitimate reasons for a driver to prefer a direction other than that indicated. For example:

- A driver may be traveling home from work or from another location, to join other family members prior to evacuating.
- An evacuating driver may be travelling to pick up a relative, or other evacuees.
- The driver may be an emergency worker en route to perform an important activity.

The implementation of a plan <u>must</u> also be flexible enough for the application of sound judgment by the traffic guide.

The traffic management plan is the outcome of the following process:

1. The existing TCP and ACP identified by the offsite agencies in their existing emergency plans serve as the basis of the traffic management plan, as per NUREG/CR-7002.
2. Computer analysis of the evacuation traffic flow environment (see Figures 7-3 through 7-6).

    This analysis identifies the best routing and those critical intersections that experience pronounced congestion. Any critical intersections that are not identified in the existing offsite plans are suggested as additional TCPs and ACPs.
3. The existing TCP and ACP, and how they were applied in this study, are discussed in Appendix G.

4. Prioritization of TCP and ACP.

   Application of traffic and access control at some TCPs and ACPs will have a more pronounced influence on expediting traffic movements than at other TCPs and ACPs. For example, TCPs controlling traffic originating from areas in close proximity to the power plant could have a more beneficial effect on minimizing potential exposure to radioactivity than those TCPs located far from the power plant. As shown in Figures 7-3 through 7-6, traffic congestion is concentrated between the towns of Mineral and Louisa. Those existing TCP and ACP in this area, especially along SR-618 westbound towards Mineral and SR-208/SR-22 westbound at the Louisa town line, should be considered top priority when assigning personnel and equipment for traffic and access control.

The use of Intelligent Transportation Systems (ITS) technologies (if available) can reduce manpower and equipment needs, while still facilitating the evacuation process. Dynamic Message Signs (DMS) can be placed within the EPZ to provide information to travelers regarding traffic conditions, route selection, and assistance center information. DMS can also be placed outside of the EPZ to warn motorists to avoid using routes that may conflict with the flow of evacuees away from the power plant. Highway Advisory Radio (HAR) can be used to broadcast information to evacuees en route through their vehicle stereo systems. Automated Traveler Information Systems (ATIS) can also be used to provide evacuees with information. Internet websites can provide traffic and evacuation route information before the evacuee begins their trip, while on board navigation systems (GPS units), cell phones, and pagers can be used to provide information en route. These are only several examples of how ITS technologies can benefit the evacuation process. Consideration should be given that ITS technologies be used to facilitate the evacuation process, and any additional signage placed should consider evacuation needs.

The ETE analysis treated all controlled intersections that are existing TCP or ACP locations in the offsite agency plans for an evacuation of the entire EPZ as being controlled by actuated signals.

Chapters 2N and 5G, and Part 6 of the 2009 MUTCD are particularly relevant and should be reviewed during emergency response training.

The ETE calculations reflect the assumption that all “external-external” trips are interdicted and diverted after 2 hours have elapsed from the ATE.

All transit vehicles and other responders entering the EPZ to support the evacuation are assumed to be unhindered by personnel manning ACPs and TCPs.

Study Assumptions 5 and 6 in Section 2.3 discuss ACP and TCP staffing schedules and operations.

10 EVACUATION ROUTES

Evacuation routes are comprised of two distinct components:

- Routing from a PAZ being evacuated to the boundary of the Evacuation Region and thence out of the EPZ.
- Routing of transit-dependent evacuees from the EPZ boundary to Evacuation Assembly Centers.

Evacuees will select routes within the EPZ in such a way as to minimize their exposure to risk. This expectation is met by the DYNEV II model routing traffic away from the location of the plant, to the extent practicable. The DTRAD model satisfies this behavior by routing traffic so as to balance traffic demand relative to the available highway capacity to the extent possible. See Appendices B through D for further discussion.

The routing of transit-dependent evacuees from the EPZ boundary to Evacuation Assembly Centers (EAC) is designed to minimize the amount of travel outside the EPZ, from the points where these routes cross the EPZ boundary.

Figure 10-1 presents the general population and school EAC for evacuees. The major evacuation routes for the EPZ are presented in Figure 10-2.

It is assumed that all school evacuees will be taken to the appropriate EAC and subsequently picked up by parents or guardians. Transit-dependent evacuees are transported to the nearest EAC for each county. This study does not consider the transport of evacuees from EAC to congregate care centers, if the counties do make the decision to relocate evacuees.

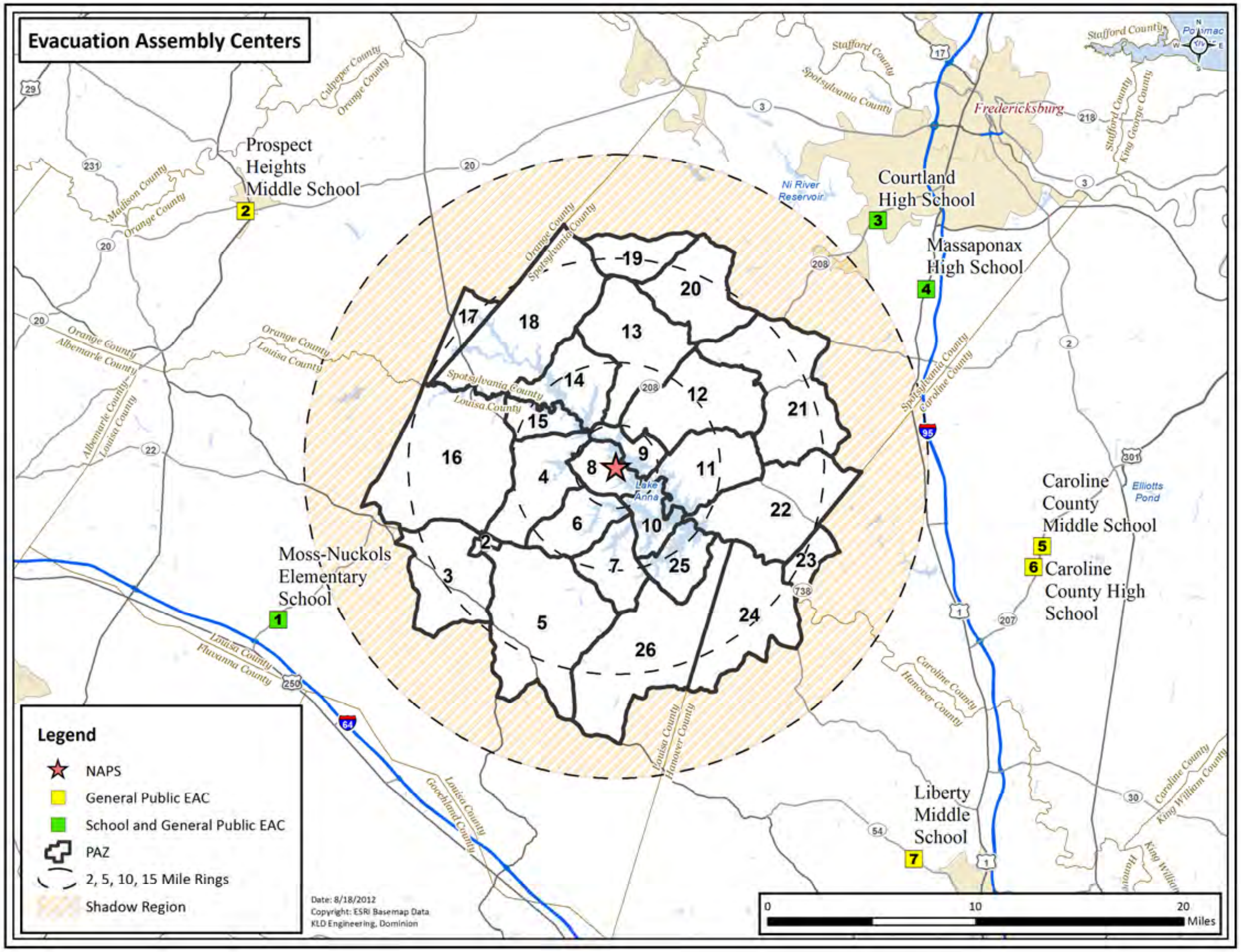


Figure 10-1. General Population and School Evacuation Assembly Centers

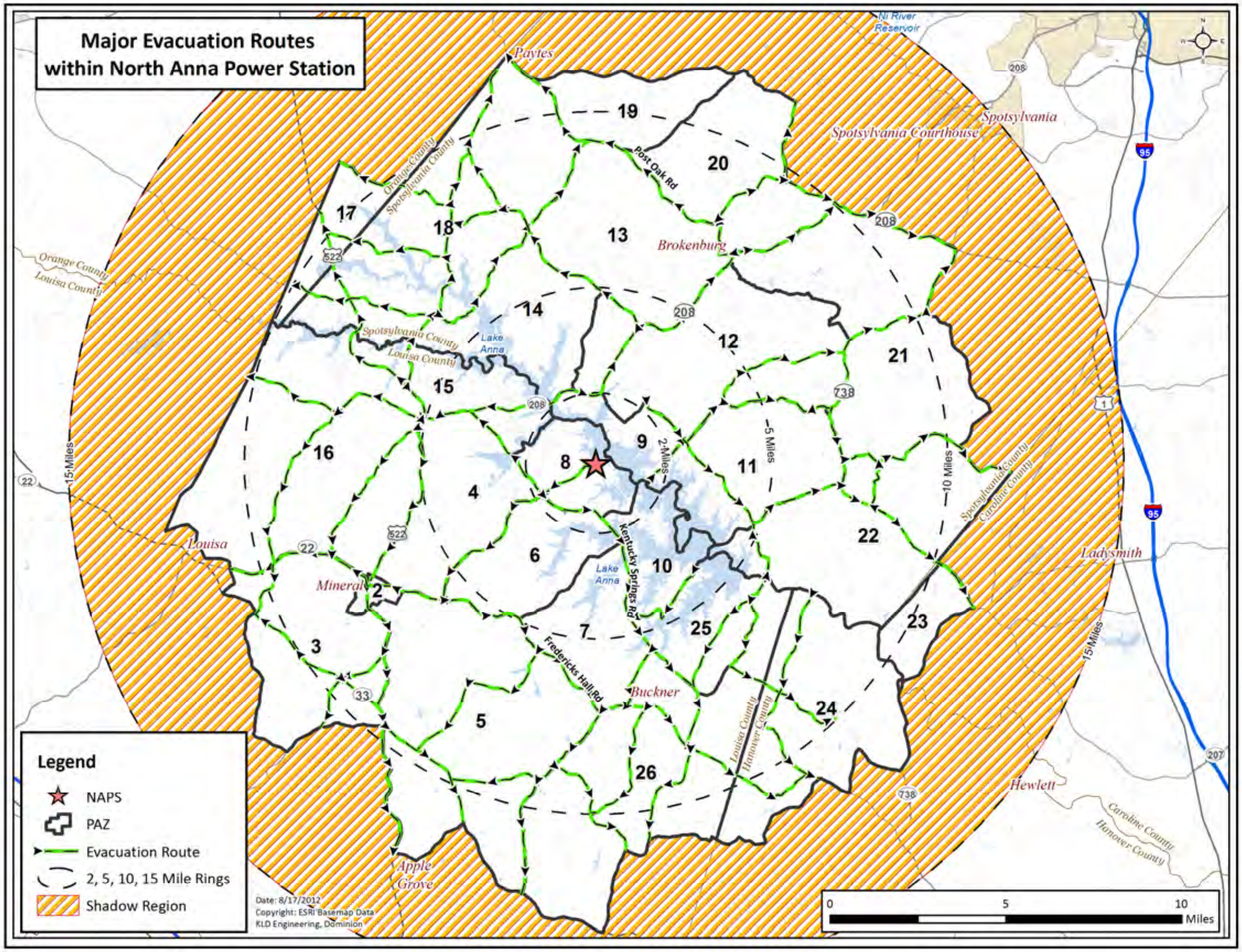


Figure 10-2. Major Evacuation Routes

11 SURVEILLANCE OF EVACUATION OPERATIONS

There is a need for surveillance of traffic operations during the evacuation. There is also a need to clear any blockage of roadways arising from accidents or vehicle disablement. Surveillance can take several forms.

1. Traffic control personnel, located at Traffic Control and Access Control points, provide fixed-point surveillance.
2. Ground patrols may be undertaken along well-defined paths to ensure coverage of those highways that serve as major evacuation routes.
3. Aerial surveillance of evacuation operations may also be conducted using helicopter or fixed-wing aircraft, if available.
4. Cellular phone calls (if cellular coverage exists) from motorists may also provide direct field reports of road blockages.

These concurrent surveillance procedures are designed to provide coverage of the entire EPZ as well as the area around its periphery. It is the responsibility of the Counties to support an emergency response system that can receive messages from the field and be in a position to respond to any reported problems in a timely manner. This coverage should quickly identify, and expedite the response to any blockage caused by a disabled vehicle.

Tow Vehicles

In a low-speed traffic environment, any vehicle disablement is likely to arise due to a low-speed collision, mechanical failure or the exhaustion of its fuel supply. In any case, the disabled vehicle can be pushed onto the shoulder, thereby restoring traffic flow. Past experience in other emergencies indicates that evacuees who are leaving an area often perform activities such as pushing a disabled vehicle to the side of the road without prompting.

While the need for tow vehicles is expected to be low under the circumstances described above, it is still prudent to be prepared for such a need. Consideration should be given that tow trucks with a supply of gasoline be deployed at strategic locations within, or just outside, the EPZ. These locations should be selected so that:

- They permit access to key, heavily loaded, evacuation routes.
- Responding tow trucks would most likely travel counter-flow relative to evacuating traffic.

Consideration should also be given that the state and local emergency management agencies encourage gas stations to remain open during the evacuation.

12 CONFIRMATION TIME

It is necessary to confirm that the evacuation process is effective in the sense that the public is complying with the Advisory to Evacuate. The EPZ county radiological emergency response plans do not discuss a procedure for confirming evacuation. Should procedures not already exist, the following alternative or complementary approach is suggested.

The suggested procedure employs a stratified random sample and a telephone survey. The size of the sample is dependent on the expected number of households that do not comply with the Advisory to Evacuate. It is reasonable to assume for the purpose of estimating sample size that at least 80 percent of the population within the EPZ will comply with the Advisory to Evacuate. On this basis, an analysis could be undertaken (see Table 12-1) to yield an estimated sample size of approximately 300.

The confirmation process should start at about 2¾ hours after the Advisory to Evacuate, which is when approximately 90 percent of resident evacuees have completed their mobilization activities (see Table 5-9). At this time, virtually all evacuees will have departed on their respective trips and the local telephone system will be largely free of traffic.

As indicated in Table 12-1, approximately 7½ person hours are needed to complete the telephone survey. If six people are assigned to this task, each dialing a different set of telephone exchanges (e.g., each person can be assigned a different set of PAZ), then the confirmation process will extend over a timeframe of about 75 minutes. Thus, the confirmation should be completed before the evacuated area is cleared. Of course, fewer people would be needed for this survey if the Evacuation Region were only a portion of the EPZ. Use of modern automated computer controlled dialing equipment or other technologies (e.g., reverse 911 or equivalent if available) can significantly reduce the manpower requirements and the time required to undertake this type of confirmation survey.

If this method is indeed used by the offsite agencies, consideration should be given to maintain a list of telephone numbers within the EPZ in the (EOC) at all times. Such a list could be purchased from vendors and could be periodically updated. As indicated above, the confirmation process should not begin until 2¾ hours after the Advisory to Evacuate, to ensure that households have had enough time to mobilize. This 2¾-hour timeframe will enable telephone operators to arrive at their workplace, obtain a call list and prepare to make the necessary phone calls.

Should the number of telephone responses (i.e., people still at home) exceed 20 percent, then the telephone survey should be repeated after an hour's interval until the confirmation process is completed.

Other techniques could also be considered. After traffic volumes decline, the personnel manning TCPs can be redeployed to travel through residential areas to observe and to confirm evacuation activities.

Table 12-1. Estimated Number of Telephone Calls Required for Confirmation of Evacuation

Problem Definition

Estimate number of phone calls, n, needed to ascertain the proportion, F of households that have not evacuated.

Reference: Burstein, H., Attribute Sampling, McGraw Hill, 1971

Given:

- No. of households plus other facilities, N, within the EPZ (est.) = 9,900
- Est. proportion, F, of households that will not evacuate = 0.20
- Allowable error margin, e: 0.05
- Confidence level, α: 0.95 (implies A = 1.96)

Applying Table 10 of cited reference,

$$p = F + e = 0.25; \;\; q = 1 - p = 0.75$$

$$n = \frac{A^2 pq + e}{e^2} = 308$$

Finite population correction:

$$n_F = \frac{nN}{n + N - 1} = 299$$

Thus, some 300 telephone calls will confirm that approximately 20 percent of the population has not evacuated. If only 10 percent of the population does not comply with the Advisory to Evacuate, then the required sample size, n_F = 211.

Est. Person Hours to complete 300 telephone calls

Assume:

- Time to dial using touch tone (random selection of listed numbers): 30 seconds
- Time for 6 rings (no answer): 36 seconds
- Time for 4 rings plus short conversation: 60 sec.
- Interval between calls: 20 sec.

Person Hours:

$$\frac{300[30 + 0.8(36) + 0.2(60) + 20]}{3600} = 7.6$$

13 RECOMMENDATIONS

The following recommendations are offered:

1. Examination of the general population ETE in Section 7 shows that the ETE for 100 percent of the population is generally 2 ½ to 3 ½ hours longer than for 90 percent of the population. Specifically, the additional time needed for the last 10 percent of the population to evacuate can be as much as double the time needed to evacuate 90 percent of the population. This non-linearity reflects the fact that these relatively few stragglers require significantly more time to mobilize (i.e. prepare for the evacuation trip) than their neighbors. This leads to two recommendations:
    a. The public outreach (information) program should emphasize the need for evacuees to minimize the time needed to prepare to evacuate (secure the home, assemble needed clothes, medicines, etc.).
    b. The decision makers should reference Table 7-1 which list the time needed to evacuate 90 percent of the population, when preparing recommended protective actions, as per NUREG/CR-7002 guidance.
2. Staged evacuation is not recommended because it is not beneficial due to the low population within the 2 and 5-mile regions of the plant and the lack of traffic congestion within these regions.
3. Counties should implement procedures whereby schools are contacted prior to dispatch of buses from the depots to get an accurate count of students needing transportation and the number of buses required (See Section 8).
4. Table 8-5 indicates that there are enough buses and wheelchair vans available to evacuate the entire transit-dependent population within the EPZ in a single wave, if transportation resources are shared by the counties. However, if for any reason transportation resources could not be shared, then Spotsylvania County would require a second wave for two of their schools in order to evacuate all schoolchildren. The second-wave ETE for schools do exceed the general population ETE at the 90th percentile. Mutual aid agreements with neighboring counties and assistance from the state could be used to address the shortfall in bus resources (See Section 8.4).
5. Intelligent Transportation Systems (ITS) such as Dynamic Message Signs (DMS), Highway Advisory Radio (HAR), Automated Traveler Information Systems (ATIS), etc. should be used to facilitate the evacuation process (See Section 9). The placement of additional signage should consider evacuation needs.
6. Counties/State should establish strategic locations to position tow trucks provided with gasoline containers in the event of a disabled vehicle during the evacuation process (see Section 11) and should encourage gas stations to remain open during the evacuation.
7. Counties/State should establish a system/procedure to confirm that the Advisory to Evacuate (ATE) is being adhered to (see the approach suggested by KLD in Section 12). Should the approach recommended by KLD in Section 12 be used, consideration should be given to keep a list of telephone numbers within the EPZ in the Emergency Operations Center (EOC) at all times.

APPENDIX A

Glossary of Traffic Engineering Terms

A. GLOSSARY OF TRAFFIC ENGINEERING TERMS

Table A-1. Glossary of Traffic Engineering Terms

Term	Definition
Analysis Network	A graphical representation of the geometric topology of a physical roadway system, which is comprised of directional links and nodes.
Link	A network link represents a specific, one-directional section of roadway. A link has both physical (length, number of lanes, topology, etc.) and operational (turn movement percentages, service rate, free-flow speed) characteristics.
Measures of Effectiveness	Statistics describing traffic operations on a roadway network.
Node	A network node generally represents an intersection of network links. A node has control characteristics, i.e., the allocation of service time to each approach link.
Origin	A location attached to a network link, within the EPZ or Shadow Region, where trips are generated at a specified rate in vehicles per hour (vph). These trips enter the roadway system to travel to their respective destinations.
Prevailing Roadway and Traffic Conditions	Relates to the physical features of the roadway, the nature (e.g., composition) of traffic on the roadway and the ambient conditions (weather, visibility, pavement conditions, etc.).
Service Rate	Maximum rate at which vehicles, executing a specific turn maneuver, can be discharged from a section of roadway at the prevailing conditions, expressed in vehicles per second (vps) or vehicles per hour (vph).
Service Volume	Maximum number of vehicles which can pass over a section of roadway in one direction during a specified time period with operating conditions at a specified Level of Service (The Service Volume at the upper bound of Level of Service, E, equals Capacity). Service Volume is usually expressed as vehicles per hour (vph).
Signal Cycle Length	The total elapsed time to display all signal indications, in sequence. The cycle length is expressed in seconds.
Signal Interval	A single combination of signal indications. The interval duration is expressed in seconds. A signal phase is comprised of a sequence of signal intervals, usually green, yellow, red.

Term	Definition
Signal Phase	A set of signal indications (and intervals) which services a particular combination of traffic movements on selected approaches to the intersection. The phase duration is expressed in seconds.
Traffic (Trip) Assignment	A process of assigning traffic to paths of travel in such a way as to satisfy all trip objectives (i.e., the desire of each vehicle to travel from a specified origin in the network to a specified destination) and to optimize some stated objective or combination of objectives. In general, the objective is stated in terms of minimizing a generalized "cost". For example, "cost" may be expressed in terms of travel time.
Traffic Density	The number of vehicles that occupy one lane of a roadway section of specified length at a point in time, expressed as vehicles per mile (vpm).
Traffic (Trip) Distribution	A process for determining the destinations of all traffic generated at the origins. The result often takes the form of a Trip Table, which is a matrix of origin-destination traffic volumes.
Traffic Simulation	A computer model designed to replicate the real-world operation of vehicles on a roadway network, so as to provide statistics describing traffic performance. These statistics are called Measures of Effectiveness.
Traffic Volume	The number of vehicles that pass over a section of roadway in one direction, expressed in vehicles per hour (vph). Where applicable, traffic volume may be stratified by turn movement.
Travel Mode	Distinguishes between private auto, bus, rail, pedestrian and air travel modes.
Trip Table or Origin-Destination Matrix	A rectangular matrix or table, whose entries contain the number of trips generated at each specified origin, during a specified time period, that are attracted to (and travel toward) each of its specified destinations. These values are expressed in vehicles per hour (vph) or in vehicles.
Turning Capacity	The capacity associated with that component of the traffic stream which executes a specified turn maneuver from an approach at an intersection.

APPENDIX B

DTRAD: Dynamic Traffic Assignment and Distribution Model

B. DYNAMIC TRAFFIC ASSIGNMENT AND DISTRIBUTION MODEL

This section describes the integrated dynamic trip assignment and distribution model named DTRAD (Dynamic Traffic Assignment and Distribution) that is expressly designed for use in analyzing evacuation scenarios. DTRAD employs logit-based path-choice principles and is one of the models of the DYNEVII System. The DTRAD module implements path-based *Dynamic Traffic Assignment* (DTA) so that time dependent Origin-Destination (OD) trips are "assigned" to routes over the network based on prevailing traffic conditions.

To apply the DYNEV II System, the analyst must specify the highway network, link capacity information, the time-varying volume of traffic generated at all origin centroids and, optionally, a set of accessible candidate destination nodes on the periphery of the EPZ for selected origins. DTRAD calculates the optimal dynamic trip distribution (i.e., trip destinations) and the optimal dynamic trip assignment (i.e., trip routing) of the traffic generated at each origin node traveling to its set of candidate destination nodes, so as to minimize evacuee travel "cost".

Overview of Integrated Distribution and Assignment Model

The underlying premise is that the selection of destinations and routes is intrinsically coupled in an evacuation scenario. That is, people in vehicles seek to travel out of an area of potential risk as rapidly as possible by selecting the "best" routes. The model is designed to identify these "best" routes in a manner that realistically distributes vehicles from origins to destinations and routes them over the highway network, in a consistent and optimal manner, reflecting evacuee behavior.

For each origin, a set of "candidate destination nodes" is selected by the software logic and by the analyst to reflect the desire by evacuees to travel away from the power plant and to access major highways. The specific destination nodes within this set that are selected by travelers and the selection of the connecting paths of travel, are both determined by DTRAD. This determination is made by a logit-based path choice model in DTRAD, so as to minimize the trip "cost", as discussed later.

The traffic loading on the network and the consequent operational traffic environment of the network (density, speed, throughput on each link) vary over time as the evacuation takes place. The DTRAD model, which is interfaced with the DYNEV simulation model, executes a succession of "sessions" wherein it computes the optimal routing and selection of destination nodes for the conditions that exist at that time.

Interfacing the DYNEV Simulation Model with DTRAD

The DYNEV II system reflects NRC guidance that evacuees will seek to travel in a general direction away from the location of the hazardous event. An algorithm was developed to support the DTRAD model in dynamically varying the Trip Table (O-D matrix) over time from one DTRAD session to the next. Another algorithm executes a "mapping" from the specified "geometric" network (link-node analysis network) that represents the physical highway system, to a "path" network that represents the vehicle [turn] movements. DTRAD computations are performed on the "path" network: DYNEV simulation model, on the "geometric" network.

DTRAD Description

DTRAD is the DTA module for the DYNEV II System.

When the road network under study is large, multiple routing options are usually available between trip origins and destinations. The problem of loading traffic demands and propagating them over the network links is called Network Loading and is addressed by DYNEVII using macroscopic traffic simulation modeling. Traffic assignment deals with computing the distribution of the traffic over the road network for given O-D demands and is a model of the route choice of the drivers. Travel demand changes significantly over time, and the road network may have time dependent characteristics, e.g., time-varying signal timing or reduced road capacity because of lane closure, or traffic congestion. To consider these time dependencies, DTA procedures are required.

The DTRAD DTA module represents the dynamic route choice behavior of drivers, using the specification of dynamic origin-destination matrices as flow input. Drivers choose their routes through the network based on the travel cost they experience (as determined by the simulation model). This allows traffic to be distributed over the network according to the time-dependent conditions. The modeling principles of D-TRAD include:

- It is assumed that drivers not only select the best route (i.e., lowest cost path) but some also select less attractive routes. The algorithm implemented by DTRAD archives several “efficient” routes for each O-D pair from which the drivers choose.
- The choice of one route out of a set of possible routes is an outcome of “discrete choice modeling”. Given a set of routes and their generalized costs, the percentages of drivers that choose each route is computed. The most prevalent model for discrete choice modeling is the logit model. DTRAD uses a variant of Path-Size-Logit model (PSL). PSL overcomes the drawback of the traditional multinomial logit model by incorporating an additional deterministic path size correction term to address path overlapping in the random utility expression.
- DTRAD executes the TA algorithm on an abstract network representation called "the path network" which is built from the actual physical link-node analysis network. This execution continues until a stable situation is reached: the volumes and travel times on the edges of the path network do not change significantly from one iteration to the next. The criteria for this convergence are defined by the user.
- Travel “cost” plays a crucial role in route choice. In DTRAD, path cost is a linear summation of the generalized cost of each link that comprises the path. The generalized cost for a link, a, is expressed as

  $$c_a = \alpha t_a + \beta l_a + \gamma s_a ,$$

  where c_a is the generalized cost for link a, and α, β, and γ are cost coefficients for link travel time, distance, and supplemental cost, respectively. Distance and supplemental costs are defined as invariant properties of the network model, while travel time is a dynamic property dictated by prevailing traffic conditions. The DYNEV simulation model computes travel times on all edges in the network and DTRAD uses that information to constantly update the costs of paths. The route choice decision model in the next simulation iteration uses these updated values to adjust the route choice behavior. This way, traffic demands are dynamically re-assigned based on time dependent conditions. The interaction between the DTRAD traffic assignment and DYNEV II simulation models is depicted in Figure B-1. Each round of interaction is called a Traffic Assignment Session (TA session). A TA session is composed of multiple iterations, marked as loop B in the figure.

- The supplemental cost is based on the "survival distribution" (a variation of the exponential distribution).The Inverse Survival Function is a "cost" term in DTRAD to represent the potential risk of travel toward the plant:

  $s_a = - \beta \ln (p), 0 \leq p \leq l ; \beta > 0$

  $p = \frac{d_n}{d_0}$

  d_n = Distance of node, n, from the plant
  d_0 =Distance from the plant where there is zero risk
  β = Scaling factor

The value of d_o = 15 miles, the outer distance of the shadow region. Note that the supplemental cost, s_a, of link, a, is (high, low), if its downstream node, n, is (near, far from) the power plant.

Network Equilibrium

In 1952, John Wardrop wrote:

> *Under equilibrium conditions traffic arranges itself in congested networks in such a way that no individual trip-maker can reduce his path costs by switching routes.*

The above statement describes the “User Equilibrium” definition, also called the “Selfish Driver Equilibrium”. It is a hypothesis that represents a [hopeful] condition that evolves over time as drivers search out alternative routes to identify those routes that minimize their respective “costs”. It has been found that this “equilibrium” objective to minimize costs is largely realized by most drivers who routinely take the same trip over the same network at the same time (i.e., commuters). Effectively, such drivers “learn” which routes are best for them over time. Thus, the traffic environment “settles down” to a near-equilibrium state.

Clearly, since an emergency evacuation is a sudden, unique event, it does not constitute a long-term learning experience which can achieve an equilibrium state. Consequently, DTRAD was not designed as an equilibrium solution, but to represent drivers in a new and unfamiliar situation, who respond in a flexible manner to real-time information (either broadcast or observed) in such a way as to minimize their respective costs of travel.

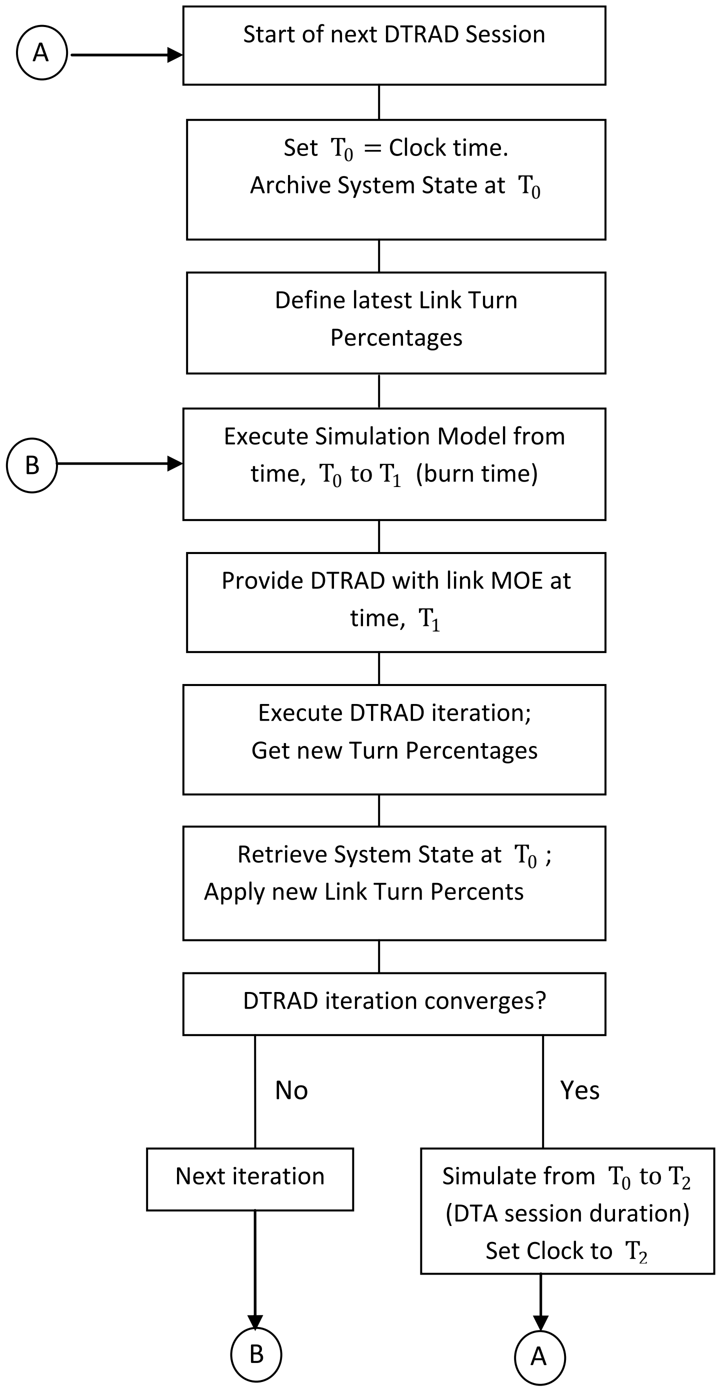


Figure B-1. Flow Diagram of Simulation-DTRAD Interface

APPENDIX C

DYNEV Traffic Simulation Model

C. DYNEV TRAFFIC SIMULATION MODEL

The DYNEV traffic simulation model is a *macroscopic* model that describes the operations of traffic flow in terms of aggregate variables: vehicles, flow rate, mean speed, volume, density, queue length, *on each link*, for each turn movement, during each Time Interval (simulation time step). The model generates trips from "sources" and from Entry Links and introduces them onto the analysis network at rates specified by the analyst based on the mobilization time distributions. The model simulates the movements of all vehicles on all network links over time until the network is empty. At intervals, the model outputs Measures of Effectiveness (MOE) such as those listed in Table C-1.

Model Features Include:

- Explicit consideration is taken of the variation in density over the time step; an iterative procedure is employed to calculate an average density over the simulation time step for the purpose of computing a mean speed for moving vehicles.
- Multiple turn movements can be serviced on one link; a separate algorithm is used to estimate the number of (fractional) lanes assigned to the vehicles performing each turn movement, based, in part, on the turn percentages provided by the DTRAD model.
- At any point in time, traffic flow on a link is subdivided into two classifications: queued and moving vehicles. The number of vehicles in each classification is computed. Vehicle spillback, stratified by turn movement for each network link, is explicitly considered and quantified. The propagation of stopping waves from link to link is computed within each time step of the simulation. There is no "vertical stacking" of queues on a link.
- Any link can accommodate "source flow" from zones via side streets and parking facilities that are not explicitly represented. This flow represents the evacuating trips that are generated at the source.
- The relation between the number of vehicles occupying the link and its storage capacity is monitored every time step for every link and for every turn movement. If the available storage capacity on a link is exceeded by the demand for service, then the simulator applies a "metering" rate to the entering traffic from both the upstream feeders and source node to ensure that the available storage capacity is not exceeded.
- A "path network" that represents the specified traffic movements from each network link is constructed by the model; this path network is utilized by the DTRAD model.
- A two-way interface with DTRAD: (1) provides link travel times; (2) receives data that translates into link turn percentages.
- Provides MOE to animation software, EVAN
- Calculates ETE statistics

All traffic simulation models are data-intensive. Table C-2 outlines the necessary input data elements.

To provide an efficient framework for defining these specifications, the physical highway environment is represented as a network. The unidirectional links of the network represent roadway sections: rural, multi-lane, urban streets or freeways. The nodes of the network generally represent intersections or points along a section where a geometric property changes (e.g. a lane drop, change in grade or free flow speed).

Figure C-1 is an example of a small network representation. The freeway is defined by the sequence of links, (20, 21), (21, 22), and (22, 23). Links (8001, 19) and (3, 8011) are Entry and Exit links, respectively. An arterial extends from node 3 to node 19 and is partially subsumed within a grid network. Note that links (21, 22) and (17, 19) are grade-separated.

Table C-1. Selected Measures of Effectiveness Output by DYNEV II

Measure	Units	Applies To
Vehicles Discharged	Vehicles	Link, Network, Exit Link
Speed	Miles/Hours (mph)	Link, Network
Density	Vehicles/Mile/Lane	Link
Level of Service	LOS	Link
Content	Vehicles	Network
Travel Time	Vehicle-hours	Network
Evacuated Vehicles	Vehicles	Network, Exit Link
Trip Travel Time	Vehicle-minutes/trip	Network
Capacity Utilization	Percent	Exit Link
Attraction	Percent of total evacuating vehicles	Exit Link
Max Queue	Vehicles	Node, Approach
Time of Max Queue	Hours:minutes	Node, Approach
Route Statistics	Length (mi); Mean Speed (mph); Travel Time (min)	Route
Mean Travel Time	Minutes	Evacuation Trips; Network

Table C-2. Input Requirements for the DYNEV II Model

HIGHWAY NETWORK

- Links defined by upstream and downstream node numbers
- Link lengths
- Number of lanes (up to 9) and channelization
- Turn bays (1 to 3 lanes)
- Destination (exit) nodes
- Network topology defined in terms of downstream nodes for each receiving link
- Node Coordinates (X,Y)
- Nuclear Power Plant Coordinates (X,Y)

GENERATED TRAFFIC VOLUMES

- On all entry links and source nodes (origins), by Time Period

TRAFFIC CONTROL SPECIFICATIONS

- Traffic signals: link-specific, turn movement specific
- Signal control treated as fixed time or actuated
- Location of traffic control points (these are represented as actuated signals)
- Stop and Yield signs
- Right-turn-on-red (RTOR)
- Route diversion specifications
- Turn restrictions
- Lane control (e.g. lane closure, movement-specific)

DRIVER'S AND OPERATIONAL CHARACTERISTICS

- Driver's (vehicle-specific) response mechanisms: free-flow speed, discharge headway
- Bus route designation.

DYNAMIC TRAFFIC ASSIGNMENT

- Candidate destination nodes for each origin (optional)
- Duration of DTA sessions
- Duration of simulation "burn time"
- Desired number of destination nodes per origin

INCIDENTS

- Identify and Schedule of closed lanes
- Identify and Schedule of closed links

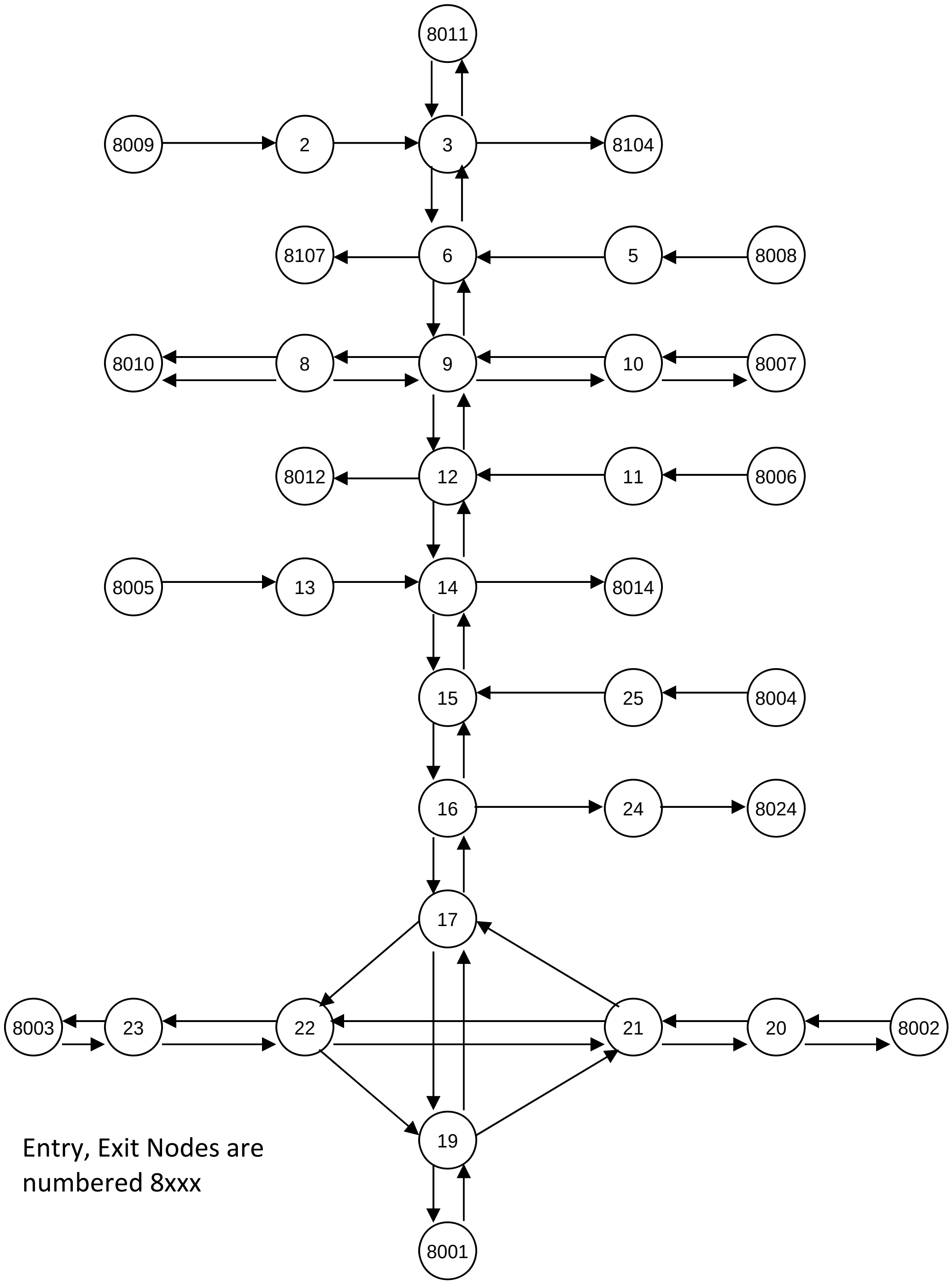


Figure C-1. Representative Analysis Network

C.1 Methodology

C.1.1 The Fundamental Diagram

It is necessary to define the fundamental diagram describing flow-density and speed-density relationships. Rather than "settling for" a triangular representation, a more realistic representation that includes a "capacity drop", (I-R)Q_{max}, at the critical density when flow conditions enter the forced flow regime, is developed and calibrated for each link. This representation, shown in Figure C-2, asserts a constant free speed up to a density, k_f, and then a linear reduction in speed in the range, $k_f \leq k \leq k_c = 45$ vpm, the density at capacity. In the flow-density plane, a quadratic relationship is prescribed in the range, $k_c < k \leq k_s = 95$ vpm which roughly represents the "stop-and-go" condition of severe congestion. The value of flow rate, Q_s, corresponding to k_s, is approximated at $0.7\,RQ_{max}$. A linear relationship between k_s and k_j completes the diagram shown in Figure C-2. Table C-3 is a glossary of terms.

The fundamental diagram is applied to <u>moving</u> traffic on every link. The specified calibration values for each link are: (1) Free speed, v_f ; (2) Capacity, Q_{max} ; (3) Critical density, $k_c = 45$ vpm ; (4) Capacity Drop Factor, R = 0.9 ; (5) Jam density, k_j . Then, $v_c = \frac{Q_{max}}{k_c}$, $k_f = k_c - \frac{(V_f - V_c)\,k_c^2}{Q_{max}}$. Setting $\bar{k} = k - k_c$, then $Q = RQ_{max} - \frac{RQ_{max}}{8333}\,\bar{k}^2$ for $0 \leq \bar{k} \leq \bar{k}_s = 50$. It can be shown that $Q = \left(0.98 - 0.0056\,\bar{k}\right) RQ_{max}$ for $\bar{k}_s \leq \bar{k} \leq \bar{k}_j$, where $\bar{k}_s = 50$ and $\bar{k}_j = 175$.

C.1.2 The Simulation Model

The simulation model solves a sequence of "unit problems". Each unit problem computes the movement of traffic on a link, for each specified turn movement, over a specified time interval (TI) which serves as the simulation time step for all links. Figure C-3 is a representation of the unit problem in the time-distance plane. Table C-3 is a glossary of terms that are referenced in the following description of the unit problem procedure.

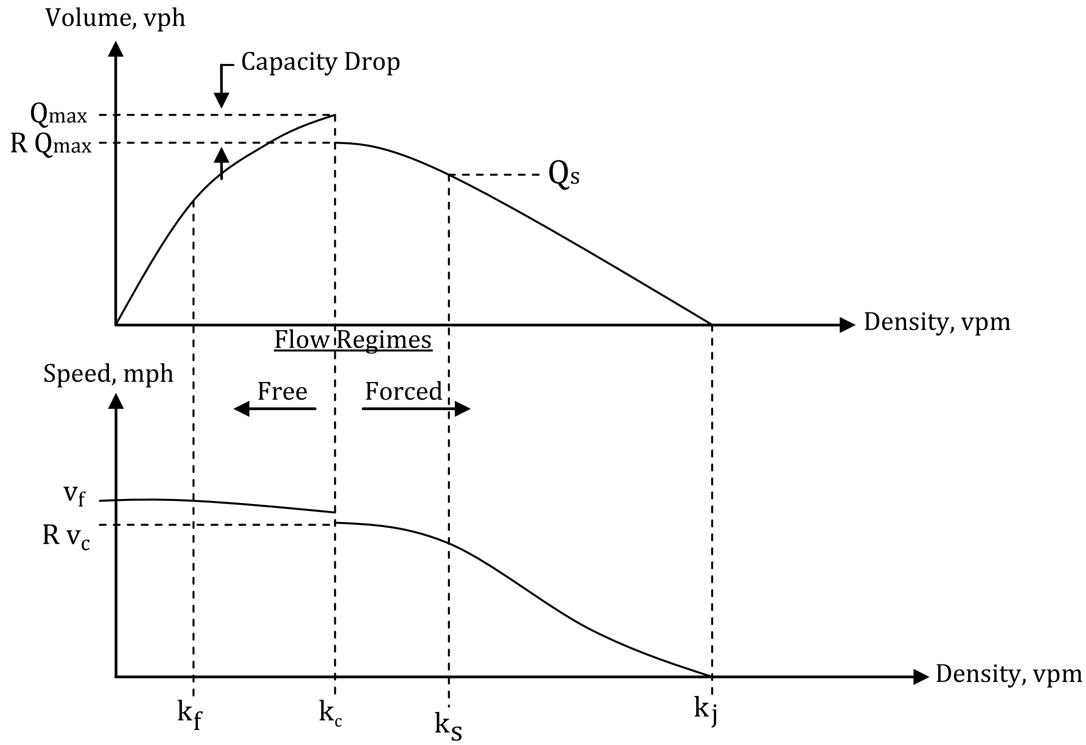


Figure C-2. Fundamental Diagrams

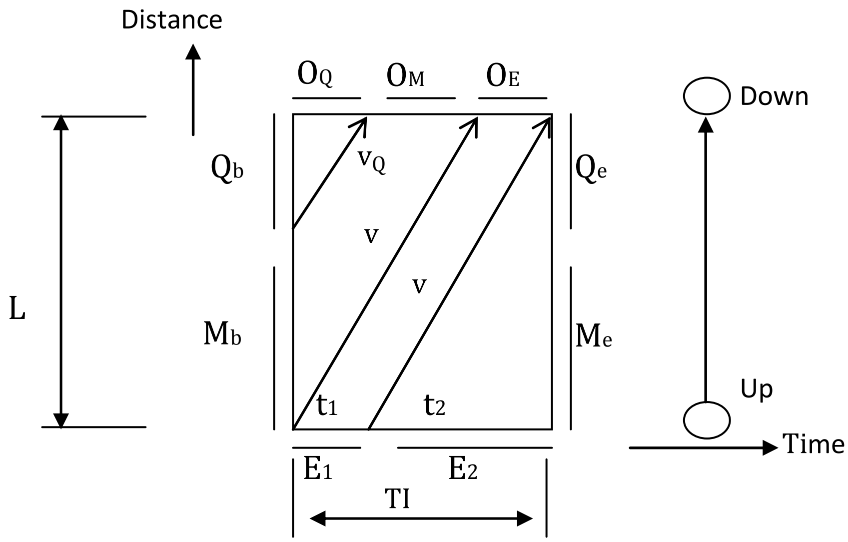


Figure C-3. A UNIT Problem Configuration with $t_1 > 0$

Table C-3. Glossary

Cap	The maximum number of vehicles, of a particular movement, that can discharge from a link within a time interval.
E	The number of vehicles, of a particular movement, that enter the link over the time interval. The portion, E_{TI}, can reach the stop-bar within the TI.
G/C	The green time: cycle time ratio that services the vehicles of a particular turn movement on a link.
h	The mean queue discharge headway, seconds.
k	Density in vehicles per lane per mile.
$\bar{k}$	The average density of <u>moving</u> vehicles of a particular movement over a TI, on a link.
L	The length of the link in feet.
L_b , L_e	The queue length in feet of a particular movement, at the [beginning, end] of a time interval.
LN	The number of lanes, expressed as a floating point number, allocated to service a particular movement on a link.
L_v	The mean effective length of a queued vehicle including the vehicle spacing, feet.
M	Metering factor (Multiplier): 1.
M_b , M_e	The number of moving vehicles on the link, of a particular movement, that are moving at the [beginning, end] of the time interval. These vehicles are assumed to be of equal spacing, over the length of link upstream of the queue.
O	The total number of vehicles of a particular movement that are discharged from a link over a time interval.
O_Q , O_M , O_E	The components of the vehicles of a particular movement that are discharged from a link within a time interval: vehicles that were Queued at the beginning of the TI; vehicles that were Moving within the link at the beginning of the TI; vehicles that Entered the link during the TI.
P_x	The percentage, expressed as a fraction, of the total flow on the link that executes a particular turn movement, x.

Q_b , Q_e	The number of queued vehicles on the link, of a particular turn movement, at the [beginning, end] of the time interval.
Q_{max}	The maximum flow rate that can be serviced by a link for a particular movement in the absence of a control device. It is specified by the analyst as an estimate of link capacity, based upon a field survey, with reference to the HCM.
R	The factor that is applied to the capacity of a link to represent the "capacity drop" when the flow condition moves into the forced flow regime. The lower capacity at that point is equal to RQ_{max} .
RCap	The remaining capacity available to service vehicles of a particular movement after that queue has been completely serviced, within a time interval, expressed as vehicles.
S_x	Service rate for movement x, vehicles per hour (vph).
t_1	Vehicles of a particular turn movement that enter a link over the first t_1 seconds of a time interval, can reach the stop-bar (in the absence of a queue down-stream) within the same time interval.
TI	The time interval, in seconds, which is used as the simulation time step.
v	The mean speed of travel, in feet per second (fps) or miles per hour (mph), of moving vehicles on the link.
v_Q	The mean speed of the last vehicle in a queue that discharges from the link within the TI. This speed differs from the mean speed of moving vehicles, v.
W	The width of the intersection in feet. This is the difference between the link length which extends from stop-bar to stop-bar and the block length.

The formulation and the associated logic presented below are designed to solve the unit problem for each sweep over the network (discussed below), for each turn movement serviced on each link that comprises the evacuation network, and for each TI over the duration of the evacuation.

Given $= Q_b, M_b, L, TI, E_0, LN, {}^{G}\!/_{C}, h, L_v, R_0, L_c, E, M$
Compute $= O, Q_e, M_e$
Define $O = O_Q + O_M + O_E$; $E = E_1 + E_2$

1. For the first sweep, s = 1, of this TI, get initial estimates of mean density, k_0, the R – factor, R_0 and entering traffic, E_0, using the values computed for the final sweep of the prior TI. For each subsequent sweep, $s > 1$, calculate $E = \sum_i P_i\ O_i + S$ where P_i, O_i are the relevant turn percentages from feeder link, i , and its total outflow (possibly metered) over this TI; S is the total source flow (possibly metered) during the current TI.
   Set iteration counter, n = 0, $k = k_0$, and $E = E_0$.

2. Calculate $v(k)$ such that $k \le 130$ using the analytical representations of the fundamental diagram.
   Calculate $\text{Cap} = \frac{Q_{max}(TI)}{3600}\left({}^{G}\!/_{C}\right) LN$, in vehicles, this value may be reduced due to metering
   Set $R = 1.0$ if ${}^{G}\!/_{C} < 1$ or if $k \le k_c$; Set $R = 0.9$ only if ${}^{G}\!/_{C} = 1$ and $k > k_c$
   Calculate queue length, $L_b = Q_b \frac{L_v}{LN}$

3. Calculate $t_1 = TI - \frac{L}{V}$. If $t_1 \prec 0$, set $t_1 = E_1 = O_E = 0$; Else, $E_1 = E\frac{t_1}{TI}$.

4. Then $E_2 = E - E_1$; $t_2 = TI - t_1$

5. If $Q_b \ge \text{Cap}$, then
   $O_Q = \text{Cap}, O_M = O_E = 0$
   If $t_1 > 0$, then
   $Q'_e = Q_b + M_b + E_1 - \text{Cap}$
   Else
   $Q'_e = Q_b - \text{Cap}$
   End if
   Calculate Q_e and M_e using Algorithm A (below)

6. Else $(Q_b \prec \text{Cap})$
   $O_Q = Q_b$, $\text{RCap} = \text{Cap} - O_Q$

7. If $M_b \le \text{RCap}$, then

8. If $t_1 > 0$, $O_M = M_b$, $O_E = \min\left(RCap - M_b, \frac{t_1\ Cap}{TI}\right) \geq 0$

$Q'_e = E_1 - O_E$

If $Q'_e > 0$, then

Calculate Q_e , M_e with Algorithm A

Else

$Q_e = 0$, $M_e = E_2$

End if

Else $(t_1 = 0)$

$O_M = \left(\frac{v(TI) - L_b}{L - L_b}\right) M_b$ and $O_E = 0$

$M_e = M_b - O_M + E$; $Q_e = 0$

End if

9. Else $(M_b > RCap)$

$O_E = 0$

If $t_1 > 0$, then

$O_M = RCap$, $Q'_e = M_b - O_M + E_1$

Calculate Q_e and M_e using Algorithm A

10. Else $(t_1 = 0)$

$M_d = \left[\left(\frac{v(TI) - L_b}{L - L_b}\right) M_b\right]$

If $M_d > RCap$, *then*

$O_M = RCap$

$Q'_e = M_d - O_M$

Apply Algorithm A to calculate Q_e and M_e

Else

$O_M = M_d$

$M_e = M_b - O_M + E$ and $Q_e = 0$

End if

End if

End if

End if

11. Calculate a new estimate of average density, $\bar{k}_n = \frac{1}{4}[k_b + 2\ k_m + k_e]$,

where k_b = density at the beginning of the TI

k_e = density at the end of the TI

k_m = density at the mid-point of the TI

All values of density apply only to the <u>moving</u> vehicles.

If $|\bar{k}_n - \bar{k}_{n-1}| > \in$ and $n < N$

where $N =$ max number of iterations, and ϵ is a convergence criterion, then

12. set $n = n + 1$, and return to step 2 to perform iteration, n, using $k = \bar{k}_n$.
End if

Computation of unit problem is now complete. Check for excessive inflow causing spillback.

13. If $Q_e + M_e > \frac{(L-W)\,LN}{L_v}$, then

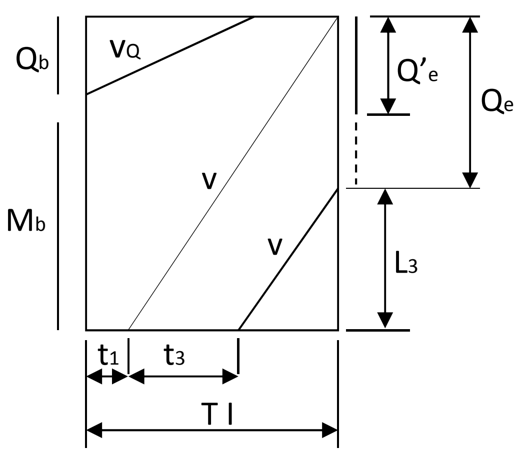
The number of excess vehicles that cause spillback is: $SB = Q_e + M_e - \frac{(L-W) \cdot LN}{L_v}$, where W is the width of the upstream intersection. To prevent spillback, meter the outflow from the feeder approaches and from the source flow, S, during this TI by the amount, SB. That is, set

$$M = 1 - \frac{SB}{(E + S)} \geq 0 \text{ , where M is the metering factor (over all movements).}$$

This metering factor is assigned appropriately to all feeder links and to the source flow, to be applied during the next network sweep, discussed later.

Algorithm A

This analysis addresses the flow environment over a TI during which moving vehicles can join a standing or discharging queue. For the case shown, $Q_b \leq Cap$, with $t_1 > 0$ and a queue of length, Q'_e , formed by that portion of M_b and E that reaches the stop-bar within the TI, but could not discharge due to inadequate capacity. That is, $Q_b + M_b + E_1 > Cap$. This queue length, $Q'_e = Q_b + M_b + E_1 - Cap$ can be extended to Q_e by traffic entering the approach during the current TI, traveling at speed, v, and reaching the rear of the queue within the TI. A portion of the entering vehicles, $E_3 = E\,\frac{t_3}{TI}$, will likely join the queue. This analysis calculates t_3 , Q_e and M_e for the input values of L, TI, v, E, t, L_v, LN, Q'_e.



When $t_1 > 0$ and $Q_b \leq Cap$:

Define: $L'_e = Q'_e \frac{L_v}{LN}$. From the sketch, $L_3 = v(TI - t_1 - t_3) = L - (Q'_e + E_3)\frac{L_v}{LN}$.

Substituting $E_3 = \frac{t_3}{TI}$ E yields: $-vt_3 + \frac{t_3}{TI}\,E\,\frac{L_v}{LN} = L - v(TI - t_1) - L'_e$. Recognizing that the first two terms on the right hand side cancel, solve for t_3 to obtain:

$$t_3 = \frac{L'_e}{\left[v - \frac{E}{TI}\frac{L_v}{LN}\right]} \qquad \text{such that} \quad 0 \le t_3 \le TI - t_1$$

If the denominator, $\left[v - \frac{E}{TI}\frac{L_v}{LN}\right] \le 0$, set $t_3 = TI - t_1$.

$$\text{Then, } Q_e = Q'_e + E\,\frac{t_3}{TI} \quad , \qquad M_e = E\left(1 - \frac{t_1 + t_3}{TI}\right)$$

The complete Algorithm A considers all flow scenarios; space limitation precludes its inclusion, here.

C.1.3 Lane Assignment

The "unit problem" is solved for each turn movement on each link. Therefore it is necessary to calculate a value, LN_x , of allocated lanes for each movement, x. If in fact all lanes are specified by, say, arrows painted on the pavement, either as full lanes or as lanes within a turn bay, then the problem is fully defined. If however there remain un-channelized lanes on a link, then an analysis is undertaken to subdivide the number of these physical lanes into turn movement specific virtual lanes, LN_x.

C.2 Implementation

C.2.1 Computational Procedure

The computational procedure for this model is shown in the form of a flow diagram as Figure C-4. As discussed earlier, the simulation model processes traffic flow for each link independently over TI that the analyst specifies; it is usually 60 seconds or longer. The first step is to execute an algorithm to define the sequence in which the network links are processed so that as many links as possible are processed <u>after</u> their feeder links are processed, within the same network sweep. Since a general network will have many closed loops, it is not possible to guarantee that every link processed will have all of its feeder links processed earlier.

The processing then continues as a succession of time steps of duration, TI, until the simulation is completed. Within each time step, the processing performs a series of "sweeps" over all network links; this is necessary to ensure that the traffic flow is synchronous over the entire network. Specifically, the sweep ensures continuity of flow among all the network links; in the context of this model, this means that the values of E, M, and S are all defined for each link such that they represent the synchronous movement of traffic from each link to all of its outbound links. These sweeps also serve to compute the metering rates that control spillback.

Within each sweep, processing solves the "unit problem" for each turn movement on each link. With the turn movement percentages for each link provided by the DTRAD model, an algorithm allocates the number of lanes to each movement serviced on each link. The timing at a signal, if any, applied at the downstream end of the link, is expressed as a G/C ratio, the signal timing needed to define this ratio is an input requirement for the model. The model also has the capability of representing, with macroscopic fidelity, the actions of actuated signals responding to the time-varying competing demands on the approaches to the intersection.

The solution of the unit problem yields the values of the number of vehicles, O, that discharge from the link over the time interval and the number of vehicles that remain on the link at the end of the time interval as stratified by queued and moving vehicles: $\mathrm{Q_e}$ and $\mathrm{M_e}$. The procedure considers each movement separately (multi-piping). After all network links are processed for a given network sweep, the updated consistent values of entering flows, E; metering rates, M; and source flows, S are defined so as to satisfy the “no spillback” condition. The procedure then performs the unit problem solutions for all network links during the following sweep.

Experience has shown that the system converges (i.e. the values of E, M and S “settle down” for all network links) in just two sweeps if the network is entirely under-saturated or in four sweeps in the presence of extensive congestion with link spillback. (The initial sweep over each link uses the final values of E and M, of the prior TI). At the completion of the final sweep for a TI, the procedure computes and stores all measures of effectiveness for each link and turn movement for output purposes. It then prepares for the following time interval by defining the values of $\mathrm{Q_b}$ and $\mathrm{M_b}$ for the start of the next TI as being those values of $\mathrm{Q_e}$ and $\mathrm{M_e}$ at the end of the prior TI. In this manner, the simulation model processes the traffic flow over time until the end of the run. Note that there is no space-discretization other than the specification of network links.

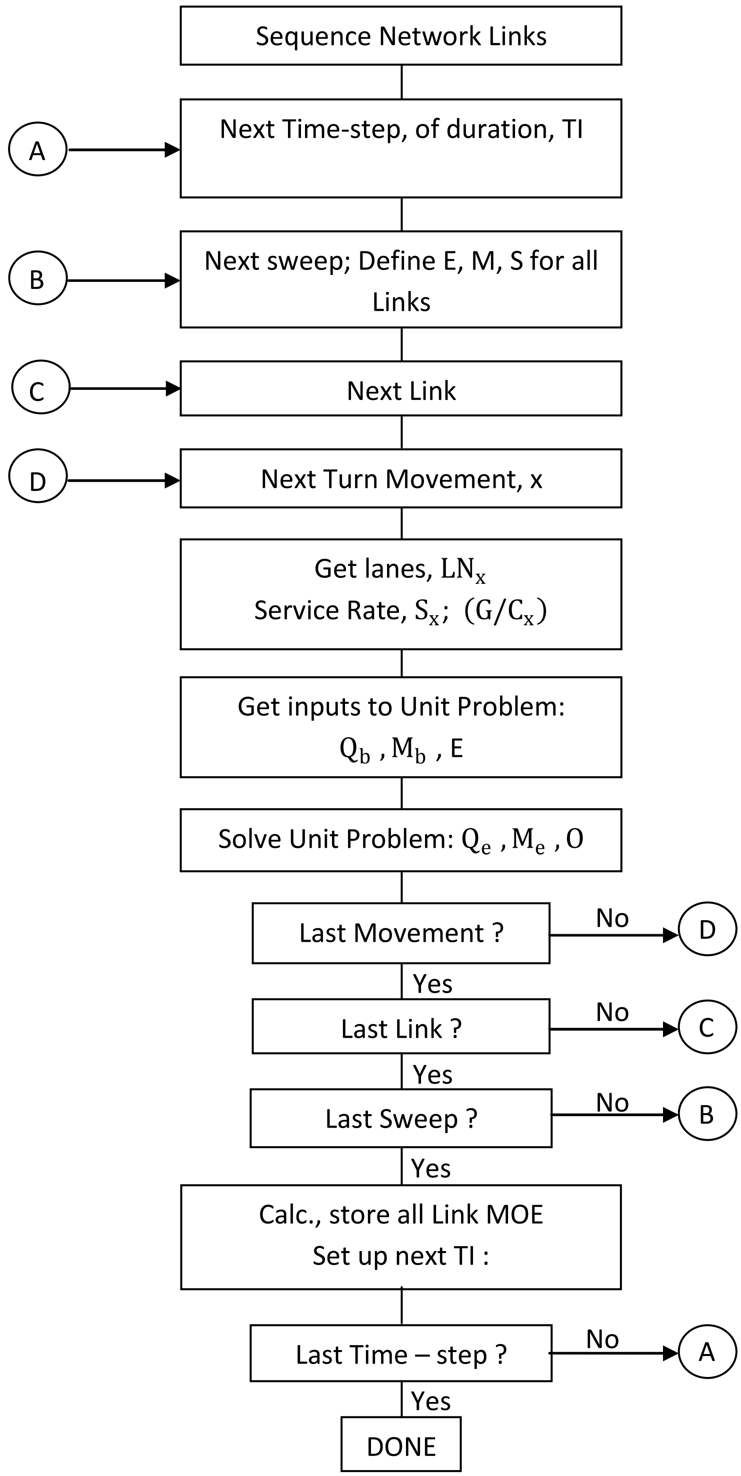


Figure C-4. Flow of Simulation Processing (See Glossary: Table C-3)

C.2.2 Interfacing with Dynamic Traffic Assignment (DTRAD)

The **DYNEV II** system reflects NRC guidance that evacuees will seek to travel in a general direction away from the location of the hazardous event. Thus, an algorithm was developed to identify an appropriate set of destination nodes for each origin based on its location and on the expected direction of travel. This algorithm also supports the DTRAD model in dynamically varying the Trip Table (O-D matrix) over time from one DTRAD session to the next.

Figure B-1 depicts the interaction of the simulation model with the DTRAD model in the **DYNEV II** system. As indicated, **DYNEV II** performs a succession of DTRAD "sessions"; each such session computes the turn link percentages for each link that remain constant for the session duration, $[T_0, T_2]$, specified by the analyst. The end product is the assignment of traffic volumes from each origin to paths connecting it with its destinations in such a way as to minimize the network-wide cost function. The output of the DTRAD model is a set of updated link turn percentages which represent this assignment of traffic.

As indicated in Figure B-1, the simulation model supports the DTRAD session by providing it with operational link MOE that are needed by the path choice model and included in the DTRAD cost function. These MOE represent the operational state of the network at a time, $T_1 \leq T_2$, which lies within the session duration, $[T_0, T_2]$. This "burn time", $T_1 - T_0$, is selected by the analyst. For each DTRAD iteration, the simulation model computes the change in network operations over this burn time using the latest set of link turn percentages computed by the DTRAD model. Upon convergence of the DTRAD iterative procedure, the simulation model accepts the latest turn percentages provided by the DTA model, returns to the origin time, T_0, and executes until it arrives at the end of the DTRAD session duration at time, T_2. At this time the next DTA session is launched and the whole process repeats until the end of the **DYNEV II** run.

Additional details are presented in Appendix B.

APPENDIX D

Detailed Description of Study Procedure

D. DETAILED DESCRIPTION OF STUDY PROCEDURE

This appendix describes the activities that were performed to compute Evacuation Time Estimates. The individual steps of this effort are represented as a flow diagram in Figure D-1. Each numbered step in the description that follows corresponds to the numbered element in the flow diagram.

Step 1

The first activity was to obtain EPZ boundary information and create a GIS base map. The base map extends beyond the Shadow Region which extends approximately 15 miles (radially) from the power plant location. The base map incorporates the local roadway topology, a suitable topographic background and the EPZ boundary.

Step 2

2010 Census block information was obtained in GIS format. This information was used to estimate the resident population within the EPZ and Shadow Region and to define the spatial distribution and demographic characteristics of the population within the study area. Employee and transient data were obtained from local/state emergency management agencies and from phone calls to transient facilities. Information concerning schools, medical and other types of special facilities within the EPZ was obtained from county sources, augmented by telephone contacts with the identified facilities.

Step 3

A kickoff meeting was conducted with major stakeholders (state and local emergency managers, on-site and off-site utility emergency managers, local and state law enforcement agencies). The purpose of the kickoff meeting was to present an overview of the work effort, identify key agency personnel, and indicate the data requirements for the study. Specific requests for information were presented to state and local emergency managers. Unique features of the study area were discussed to identify the local concerns that should be addressed by the ETE study.

Step 4

Next, a physical survey of the roadway system in the study area was conducted to determine the geometric properties of the highway sections, the channelization of lanes on each section of roadway, whether there are any turn restrictions or special treatment of traffic at intersections, the type and functioning of traffic control devices, gathering signal timings for pre-timed traffic signals, and to make the necessary observations needed to estimate realistic values of roadway capacity.

Step 5

A telephone survey of households within the EPZ was conducted (in 2007) to identify household dynamics, trip generation characteristics, and evacuation-related demographic information of the EPZ population. This information was used to determine important study factors including the average number of evacuating vehicles used by each household, and the time required to perform pre-evacuation mobilization activities.

Step 6

A computerized representation of the physical roadway system, called a link-node analysis network, was developed using the UNITES software developed by KLD. Once the geometry of the network was completed, the network was calibrated using the information gathered during the road survey (Step 4). Estimates of highway capacity for each link and other link-specific characteristics were introduced to the network description. Traffic signal timings were input accordingly. The link-node analysis network was imported into a GIS map. 2010 Census data were overlaid in the map, and origin centroids where trips would be generated during the evacuation process were assigned to appropriate links.

Step 7

The EPZ is subdivided into 25 PAZ. Based on wind direction and speed, Regions (groupings of PAZ) that may be advised to evacuate, were developed.

The need for evacuation can occur over a range of time-of-day, day-of-week, seasonal and weather-related conditions. Scenarios were developed to capture the variation in evacuation demand, highway capacity and mobilization time, for different time of day, day of the week, time of year, and weather conditions.

Step 8

The input stream for the DYNEV II model, which integrates the dynamic traffic assignment and distribution model, DTRAD, with the evacuation simulation model, was created for a prototype evacuation case – the evacuation of the entire EPZ for a representative scenario.

Step 9

After creating this input stream, the DYNEV II System was executed on the prototype evacuation case to compute evacuating traffic routing patterns consistent with the appropriate NRC guidelines. DYNEV II contains an extensive suite of data diagnostics which check the completeness and consistency of the input data specified. The analyst reviews all warning and error messages produced by the model and then corrects the database to create an input stream that properly executes to completion.

The model assigns destinations to all origin centroids consistent with a (general) radial evacuation of the EPZ and Shadow Region. The analyst may optionally supplement and/or replace these model-assigned destinations, based on professional judgment, after studying the topology of the analysis highway network. The model produces link and network-wide measures of effectiveness as well as estimates of evacuation time.

Step 10

The results generated by the prototype evacuation case are critically examined. The examination includes observing the animated graphics (using the EVAN software which operates on data produced by DYNEV II) and reviewing the statistics output by the model. This is a labor-intensive activity, requiring the direct participation of skilled engineers who possess the necessary practical experience to interpret the results and to determine the causes of any problems reflected in the results.

Essentially, the approach is to identify those bottlenecks in the network that represent locations where congested conditions are pronounced and to identify the cause of this congestion. This cause can take many forms, either as excess demand due to high rates of trip generation, improper routing, a shortfall of capacity, or as a quantitative flaw in the way the physical system was represented in the input stream. This examination leads to one of two conclusions:

- The results are satisfactory; or
- The input stream must be modified accordingly.

This decision requires, of course, the application of the user's judgment and experience based upon the results obtained in previous applications of the model and a comparison of the results of the latest prototype evacuation case iteration with the previous ones. If the results are satisfactory in the opinion of the user, then the process continues with Step 13. Otherwise, proceed to Step 11.

Step 11

There are many "treatments" available to the user in resolving apparent problems. These treatments range from decisions to reroute the traffic by assigning additional evacuation destinations for one or more sources, imposing turn restrictions where they can produce significant improvements in capacity, changing the control treatment at critical intersections so as to provide improved service for one or more movements, or in prescribing specific treatments for channelizing the flow so as to expedite the movement of traffic along major roadway systems. Such "treatments" take the form of modifications to the original prototype evacuation case input stream. All treatments are designed to improve the representation of evacuation behavior.

Step 12

As noted above, the changes to the input stream must be implemented to reflect the modifications undertaken in Step 11. At the completion of this activity, the process returns to Step 9 where the DYNEV II System is again executed.

Step 13

Evacuation of transit-dependent evacuees and special facilities are included in the evacuation analysis. Fixed routing for transit buses and for school buses, ambulances, and other transit vehicles are introduced into the final prototype evacuation case data set. DYNEV II generates route-specific speeds over time for use in the estimation of evacuation times for the transit dependent and special facility population groups.

Step 14

The prototype evacuation case was used as the basis for generating all region and scenario-specific evacuation cases to be simulated. This process was automated through the UNITES user interface. For each specific case, the population to be evacuated, the trip generation distributions, the highway capacity and speeds, and other factors are adjusted to produce a customized case-specific data set.

Step 15

All evacuation cases are executed using the DYNEV II System to compute ETE. Once results were available, quality control procedures were used to assure the results were consistent, dynamic routing was reasonable, and traffic congestion/bottlenecks were addressed properly.

Step 16

Once vehicular evacuation results are accepted, average travel speeds for transit and special facility routes were used to compute evacuation time estimates for transit-dependent permanent residents, schools, and other special facilities.

Step 17

The simulation results are analyzed, tabulated and graphed. The results were then documented, as required by NUREG/CR-7002.

Step 18

Following the completion of documentation activities, the ETE criteria checklist (see Appendix N) was completed. An appropriate report reference is provided for each criterion provided in the checklist.

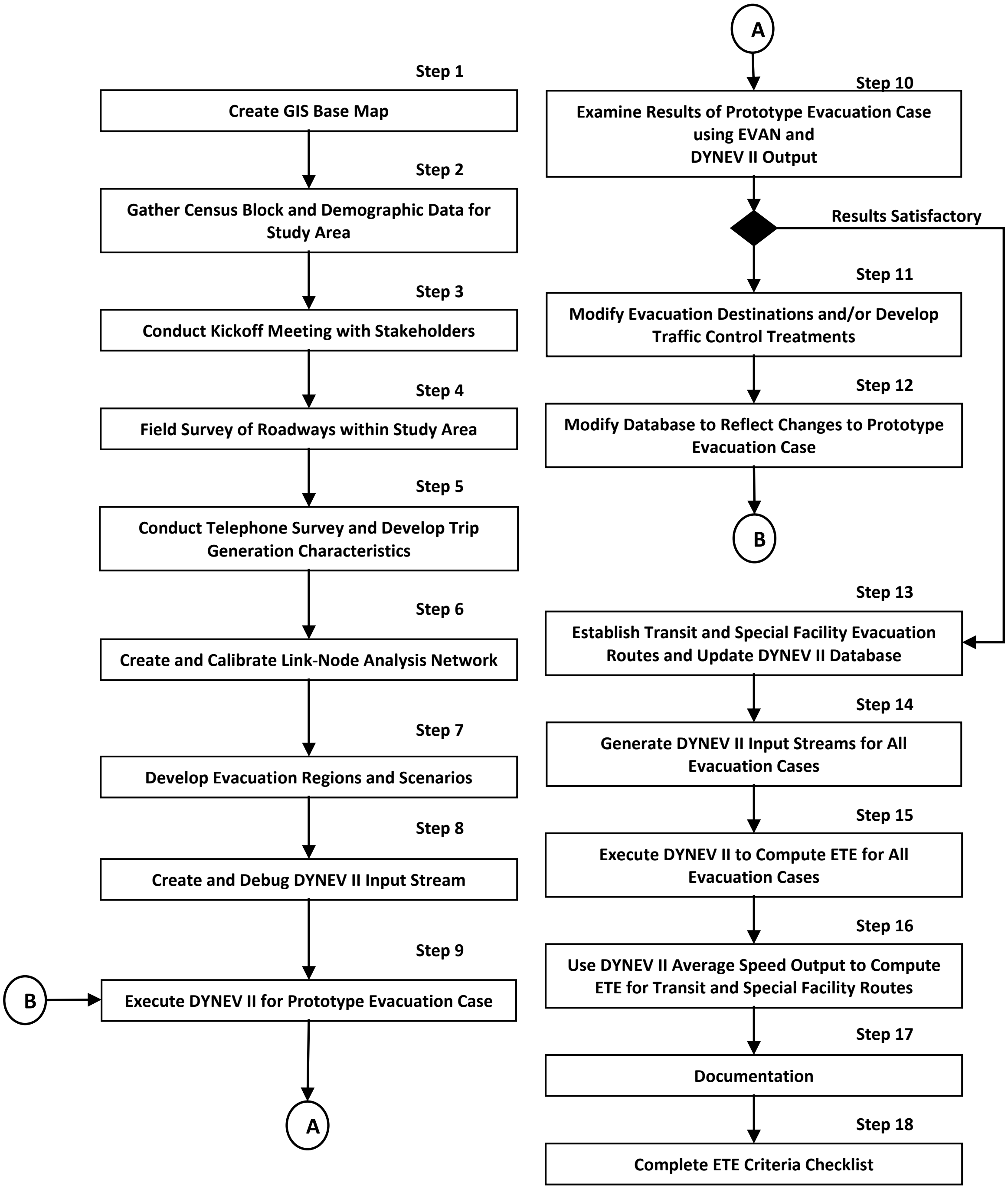


Figure D-1. Flow Diagram of Activities

APPENDIX E

Special Facility Data

E. SPECIAL FACILITY DATA

The following tables list population information, as of August 2012, for special facilities that are located within the NAPS EPZ. Special facilities are defined as schools, day care centers, hospitals and other medical care facilities. Transient population data is included in the tables for recreational areas and lodging facilities. Summer seasonal transients along the shores of Lake Anna were determined using 2010 US Census data and are not discussed in this section; Section 3.3 provides information for this transient population group. Employment data is included in the tables for major employers. Each table is grouped by county. The location of the facility is defined by its straight-line distance (miles) and direction (magnetic bearing) from the center point of the plant. Maps of each school and day care center, medical facility, major employer, recreational area and lodging facility are also provided.

Table E-1. Schools and Preschools within the EPZ

PAZ	Distance (miles)	Dire-ction	School Name	Street Address	Municipality	Phone	Enroll-ment	Staff
LOUISA COUNTY								
2	7.2	WSW	Mineral Christian Preschool[1]	51 Louisa Ave	Mineral	N/A	60	9
3	10.5	WSW	Thomas Jefferson Elementary School[1,2]	1782 Jefferson Hwy	Louisa	(540) 967-0492	545	124
3	7.8	WSW	Louisa County High School[1]	757 Davis Hwy	Louisa	(540) 894-5436	1,392	170
3	7.9	WSW	Louisa County Middle School[1]	1009 Davis Hwy	Mineral	(540) 894-5457	1,073	119
5	11.6	SSW	Jouett Elementary School[1,3]	315 Jouett School Rd	Mineral	(540) 872-3931	597	102
						Louisa County Subtotals:	*3,667*	*524*
SPOTSYLVANIA COUNTY								
12	5.2	NNE	Livingston Elementary	6057 Courthouse Rd	Spotsylvania	(540) 895-5101	444	65
21	10.3	ENE	Berkeley Elementary	5979 Partlow Road	Spotsylvania	(540) 582-5141	326	70
21	9.7	NE	Post Oak Middle School	6959 Courthouse Rd	Spotsylvania	(540) 582-7517	752	122
21	10.1	NE	Spotsylvania High School	6975 Courthouse Rd	Spotsylvania	(540) 582-3882	1,118	163
21	10.1	NE	Spotsylvania High School-Governor's School	6975 Courthouse Rd	Spotsylvania	(540) 582-3882	120	7
						Spotsylvania County Subtotals:	*2,760*	*427*
						TOTAL:	**6,427**	**951**

[1] Staff data obtained from 2008 ETE report (Revision 1 of the 2007 COLA) for Louisa County Schools.
[2] Students enrolled at Thomas Jefferson Elementary School currently attend classes at Trevilians Elementary School (outside the EPZ), due to damages from the August 2011 earthquake, and will return to the address provided above once reconstruction of the school is complete.
[3] School shelters-in-place.

Table E-2. Medical Facilities within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Cap-acity	Current Census	Ambul-atory Patients	Wheel-chair Patients	Bed-ridden Patients
LOUISA COUNTY											
3	10.5	WSW	JABA Adult Daycare	522 Industrial Dr #B	Louisa	(434) 817-5222	N/A	23	21	2	0
						Louisa County Subtotals:	-	*23*	*21*	*2*	*0*
						TOTAL:	**-**	**23**	**21**	**2**	**0**

Table E-3. Major Employers within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Employees (max shift)	% Non-EPZ	Employees (Non EPZ)
LOUISA COUNTY									
3	10.3	WSW	Tri-Dim Filters	93 Industrial Drive	Louisa	(540) 967-2600	135	50%	68
8	0.0	-	North Anna Power Station	State Hwy 700 & State Hwy 652	Mineral	(804) 237-2883	800	90%	720
						Louisa County Subtotals:	*935*	-	*788*
						TOTAL:	**935**	**-**	**788**

Table E-4. Marinas within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Transients	Vehicles
SPOTSYLVANIA COUNTY								
9	1.4	NNE	Lake Anna Marina	4303 Boggs Dr	Bumpass	(540) 895-5555	150	100
11	2.1	E	Duke's Creek Marina	3831 Breaknock Rd	Bumpass	(540) 895-5065	46	18
12	2.0	N	Sturgeon Creek Marina	5107 Courthouse Rd	Spotsylvania	(540) 895-5095	132	44
12	2.2	NNE	Rocky Branch Marina	5153 Courthouse Rd	Spotsylvania	(540) 895-5475	35	14
14	2.3	NNW	Anna Point Marina	13701 Anna Point Ln	Mineral	(540) 895-5900	151	50
14	2.2	NW	High Point Marina[1]	4634 Courthouse Rd	Mineral	(540) 895-5249	390	195
18	6.7	NW	Hunter's Landing	6320 Belmont Rd. (Route 719)	Mineral	(540) 854-5725	90	35
						Spotsylvania County Subtotals:	*994*	*456*
						TOTAL:	**994**	**456**

[1] Data obtained from 2008 ETE report (Revision 1 of the 2007 COLA)

Table E-5. Campgrounds within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Transients	Vehicles
LOUISA COUNTY								
16	6.0	WNW	Christopher Run Campground[1]	7149 Zachary Taylor Hwy	Mineral	(540) 894-4744	2,000	800
						Louisa County Subtotals:	*2,000*	*800*
SPOTSYLVANIA COUNTY								
14	4.0	NNW	Lake Anna State Park	6800 Lawyers Rd	Spotsylvania	(540) 854-5503	298	99
						Spotsylvania County Subtotals:	*298*	*99*
						TOTAL:	**2,298**	**899**

[1] Data obtained from 2008 ETE report (Revision 1 of the 2007 COLA)

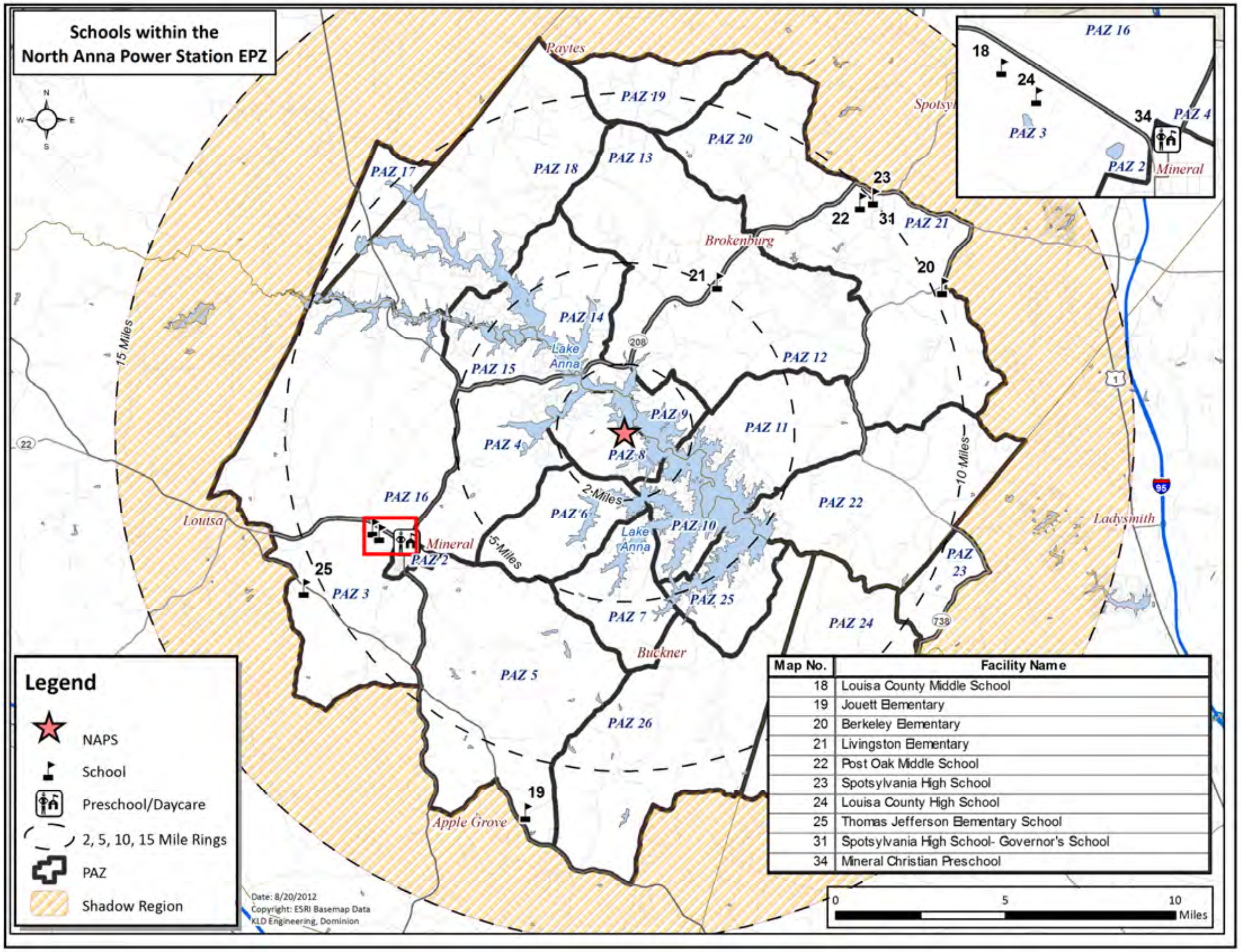
Table E-6. State Parks within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Transients	Vehicles
SPOTSYLVANIA COUNTY								
14	4.0	NNW	Lake Anna State Park	6800 Lawyers Rd	Spotsylvania	(540) 854-5503	1,920	480
						Spotsylvania County Subtotals:	*1,920*	*480*
						TOTAL:	**1,920**	**480**

Table E-7. Lodging Facilities within the EPZ

PAZ	Distance (miles)	Dire-ction	Facility Name	Street Address	Municipality	Phone	Transients	Vehicles
SPOTSYLVANIA COUNTY								
11	3.2	E	Rockland Farm Retreat[1]	3609 Lewiston Rd	Bumpass	(540) 895-5098	12	6
13	2.3	N	Lake Anna Lodge	5152 Courthouse Rd	Spotsylvania	(540) 895-5844	27	27
14	2.2	NNW	The Lighthouse Inn	4634 Courthouse Rd	Mineral	(540) 895-5249	14	7
18	6.6	NW	Littlepage Bed & Breakfast	15701 Monrovia Rd	Mineral	(540) 854-9861	8	4
						Spotsylvania County Subtotals:	*61*	*44*
						TOTAL:	**61**	**44**

[1] Data obtained from 2008 ETE report (Revision 1 of the 2007 COLA)



Map No.	Facility Name
18	Louisa County Middle School
19	Jouett Elementary
20	Berkeley Elementary
21	Livingston Elementary
22	Post Oak Middle School
23	Spotsylvania High School
24	Louisa County High School
25	Thomas Jefferson Elementary School
31	Spotsylvania High School- Governor's School
34	Mineral Christian Preschool

Figure E-1. Schools and Preschools within the EPZ

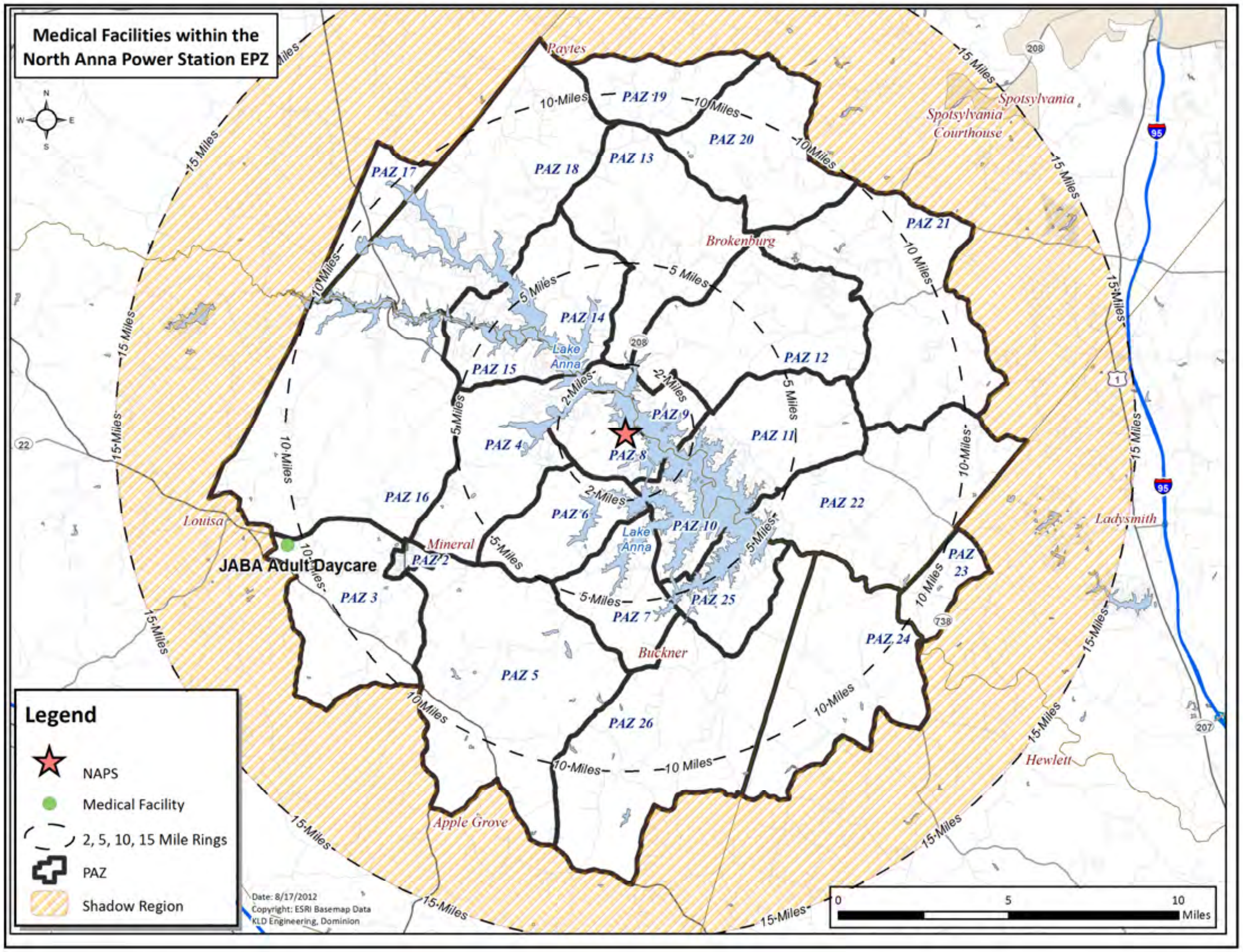


Figure E-2. Medical Facilities within the EPZ

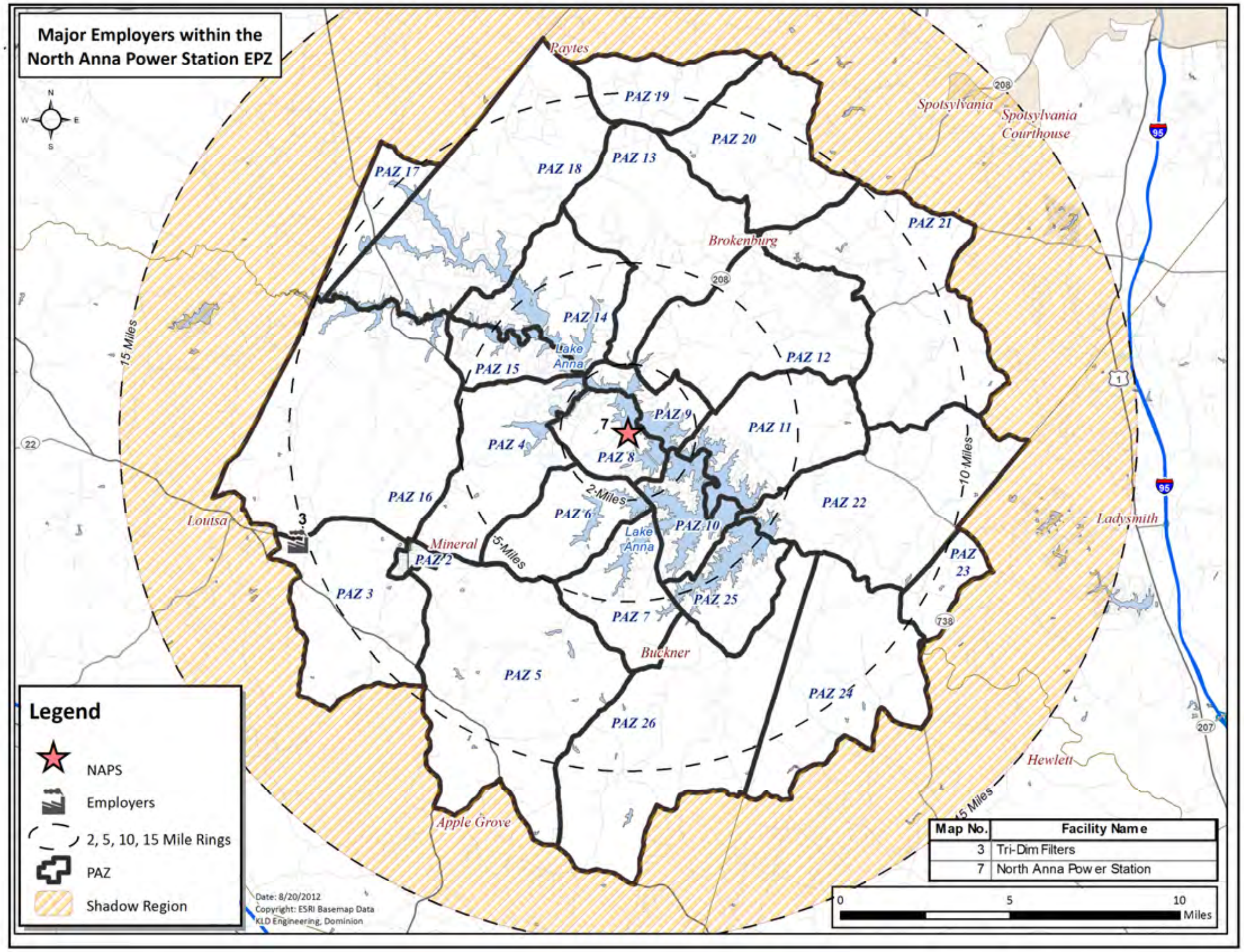


Figure E-3. Major Employers within the EPZ

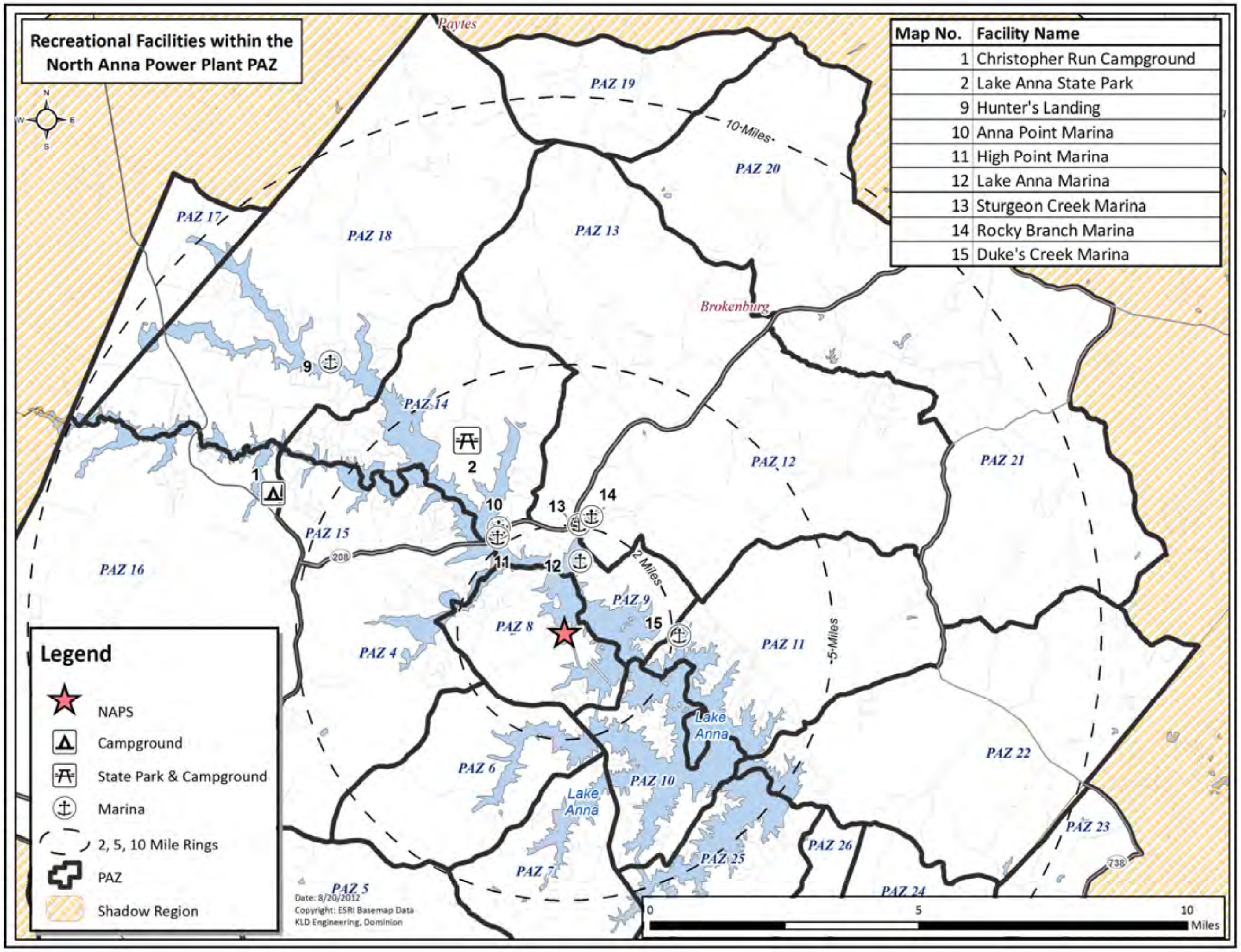
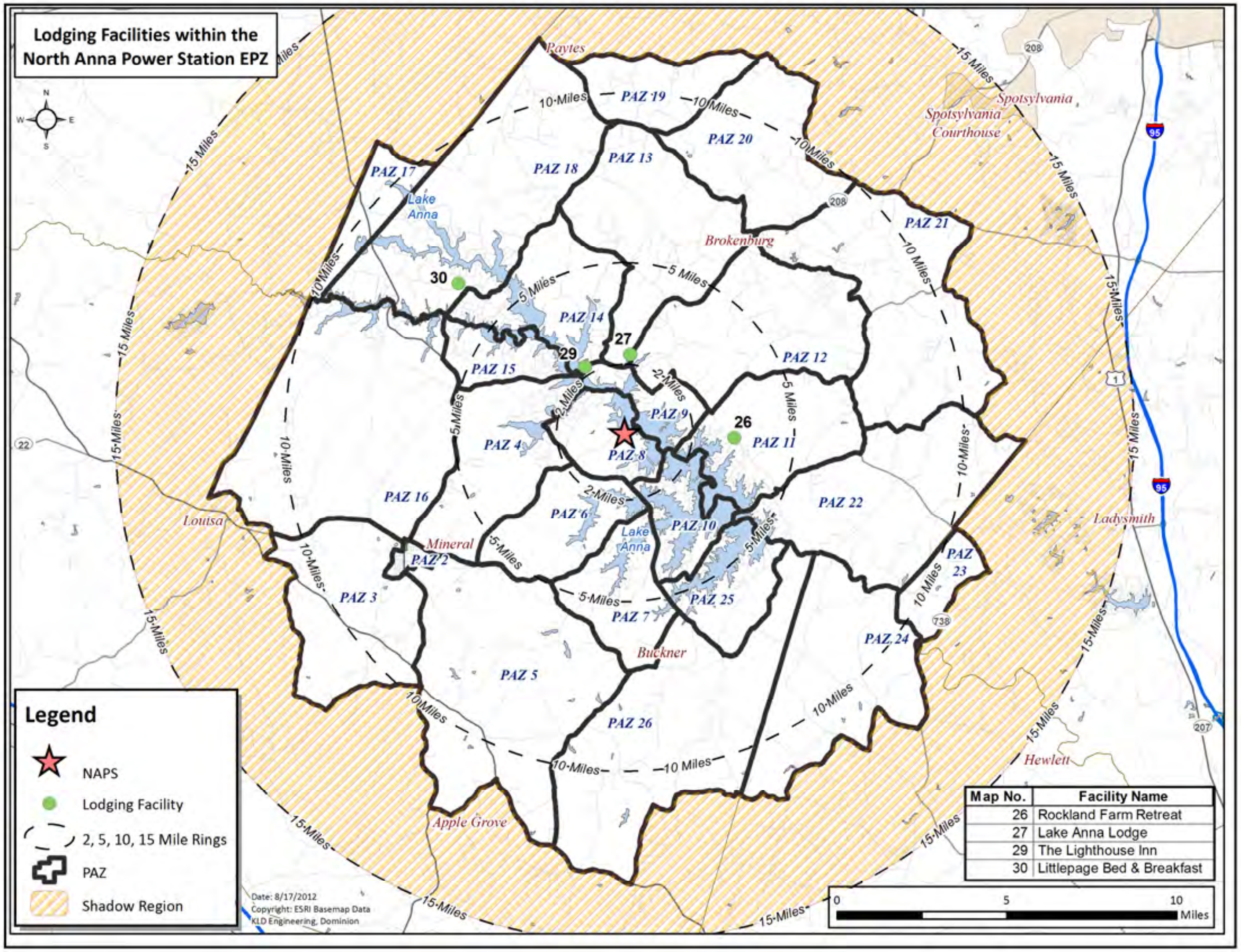


Figure E-4. Marinas, Campgrounds and State Parks within the EPZ



Map No.	Facility Name
26	Rockland Farm Retreat
27	Lake Anna Lodge
29	The Lighthouse Inn
30	Littlepage Bed & Breakfast

Figure E-5. Lodging within the EPZ

APPENDIX F

Telephone Survey

F. TELEPHONE SURVEY

F.1 Introduction

The development of evacuation time estimates for the North Anna Power Station EPZ requires the identification of travel patterns, car ownership and household size of the population within the EPZ. Demographic information can be obtained from Census data. The use of this data has several limitations when applied to emergency planning. First, the Census data do not encompass the range of information needed to identify the time required for preliminary activities (mobilization) that must be undertaken prior to evacuating the area. Secondly, Census data do not contain attitudinal responses needed from the population of the EPZ and consequently may not accurately represent the anticipated behavioral characteristics of the evacuating populace.

These concerns are addressed by conducting a telephone survey of a representative sample of the EPZ population. The survey is designed to elicit information from the public concerning family demographics and estimates of response times to well defined events. The design of the survey includes a limited number of questions of the form "What would you do if …?" and other questions regarding activities with which the respondent is familiar ("How long does it take you to …?")

F.2 Survey Instrument and Sampling Plan

Attachment A presents the final survey instrument used in this study. A draft of the instrument was submitted to stakeholders for comment. Comments were received and the survey instrument was modified accordingly, prior to conducting the survey.

Following the completion of the instrument, a sampling plan was developed. A sample size of approximately 550 **completed** survey forms yields results with a sampling error of ±4.15% at the 95% confidence level. The sample must be drawn from the EPZ population. Consequently, a list of zip codes in the EPZ was developed using GIS software. This list is shown in Table F-1. Along with each zip code, an estimate of the population and number of households in each area was determined by overlaying Census data and the EPZ boundary, again using GIS software. The proportional number of desired completed survey interviews for each area was identified, as shown in Table F-1. Note that the average household size computed in Table F-1 was an estimate for sampling purposes and was not used in the ETE study.

The completed survey adhered to the sampling plan.

Table F-1. NAPS Telephone Survey Sampling Plan

Zip Code	Population within EPZ (2000)[1]	Households	Required Sample
22534	2,061	696	52
22546	4	1	0
22553*	4,894	1,731	131
22567	45	18	1
22960	308	122	9
23015	1,446	499	38
23024	3,674	1,447	109
23093	1,448	563	42
23117	5,621	2,222	168
Total	**19,501**	**2,222**	**550**
		Average Household Size:	**2.67**

*Note: The Postal Code 22553 was subdivided (into 22553 and 22551) between 2009 and 2010; the relevant portion is now zip code 22551.

The survey discussed herein was performed in 2007. The EPZ population has increased by about 30 percent (5,887 people) between the 2000 and 2010 Census (see Section 3.1). In the intervening period, the distribution pattern of population within the EPZ has not changed, nor has the nature of the EPZ. Consequently, the use of 2007 telephone survey sampling plan and results can be justified.

Four of the questions listed in this Appendix were not asked in the 2007 survey; therefore the

[1] EPZ population used in 2007 COLA

results from the 2012 Surry Power Station telephone survey are presented. Of these questions, only one (about snow removal time) is used in the calculation of ETE.

F.3 Survey Results

The results of the survey fall into two categories. First, the household demographics of the area can be identified. Demographic information includes such factors as household size, automobile ownership, and automobile availability. The distributions of the time to perform certain pre-evacuation activities are the second category of survey results. These data are processed to develop the trip generation distributions used in the evacuation modeling effort, as discussed in Section 5.

A review of the survey instrument reveals that several questions have a “don’t know” (DK) or “refused” entry for a response. It is accepted practice in conducting surveys of this type to accept the answers of a respondent who offers a DK response for a few questions or who refuses to answer a few questions. To address the issue of occasional DK/refused responses from a large sample, the practice is to assume that the distribution of these responses is the same as the underlying distribution of the positive responses. In effect, the DK/refused responses are ignored and the distributions are based upon the positive data that is acquired.

F.3.1 Household Demographic Results

Household Size

Figure F-1 presents the distribution of household size within the EPZ. The average household contains 2.57 people. The estimated household size (2.68 persons) used to determine the survey sample (Table F-1) was drawn from Census data. The close agreement between the average household size obtained from the survey and from the Census is an indication of the reliability of the survey.

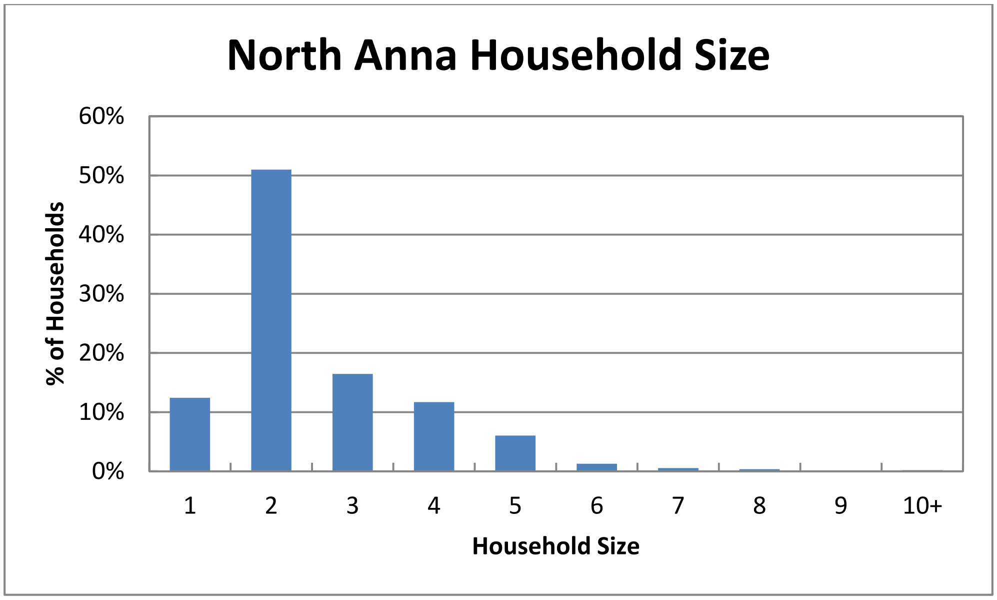


Figure F-1. Household Size in the EPZ

Automobile Ownership

The average number of automobiles available per household in the EPZ is 2.48. It should be noted that approximately 2.2 percent of households do not have access to an automobile. The distribution of automobile ownership is presented in Figure F-2. Figure F-3 and Figure F-4 present the automobile availability by household size. Note that the majority of households without access to a car are single person households. As expected, nearly all households of 2 or more people have access to at least one vehicle.

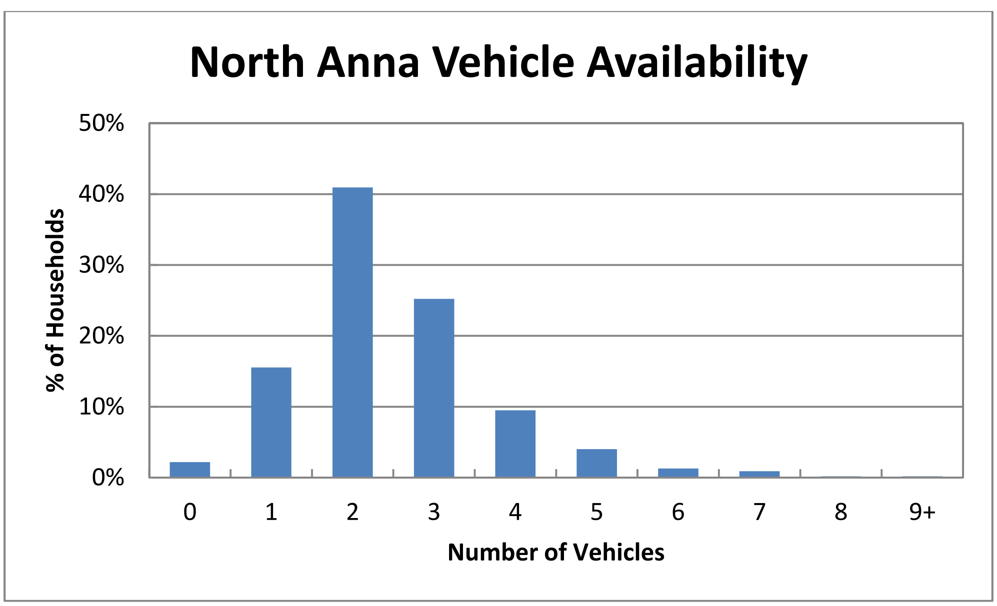


Figure F-2. Household Vehicle Availability

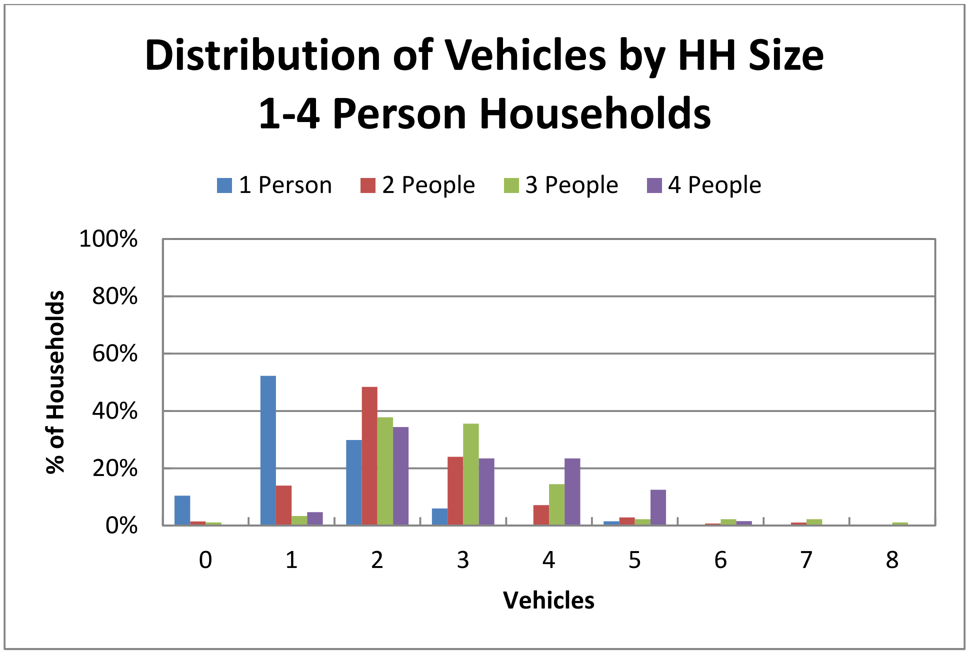


Figure F-3. Vehicle Availability - 1 to 5 Person Households

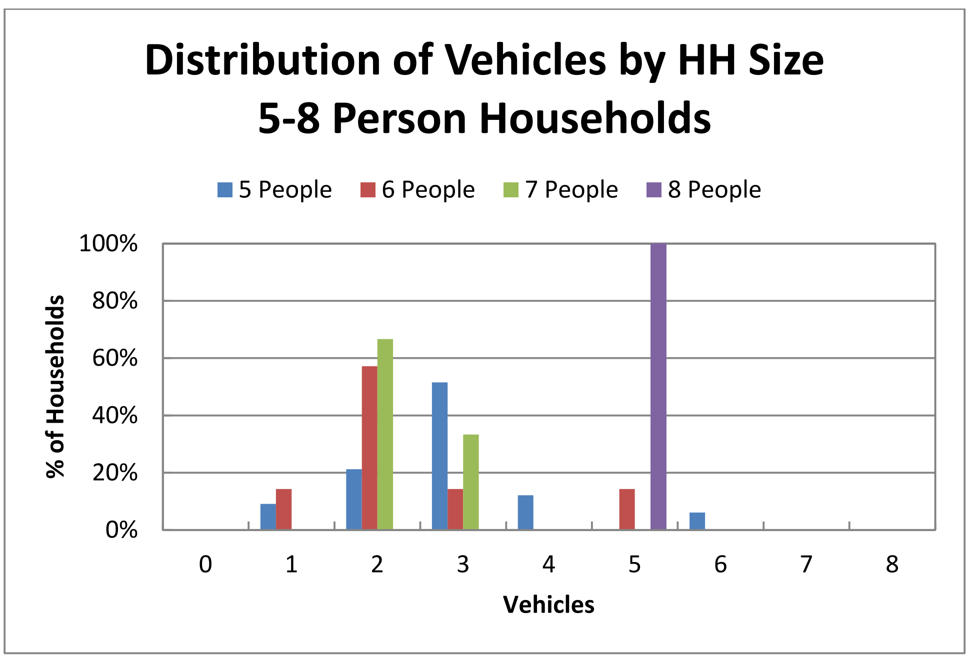


Figure F-4. Vehicle Availability - 6 to 9+ Person Households

Ridesharing

85% of the households surveyed (who do not own a vehicle) responded that they would share a ride with a neighbor, relative, or friend if a car was not available to them when advised to evacuate in the event of an emergency. Note, however, that only those households with no access to a vehicle – 20 total out of the sample size of 500 – answered this question. Thus, the results are not statistically significant. As such, the NRC recommendation of 50% ridesharing is used throughout this study. Figure F-5 presents this response.

The 2007 telephone survey did not include this question; therefore these results were taken from the 2012 telephone survey conducted for the Surry Power Station, which is located approximately 85 miles southeast of the North Anna Power Station.

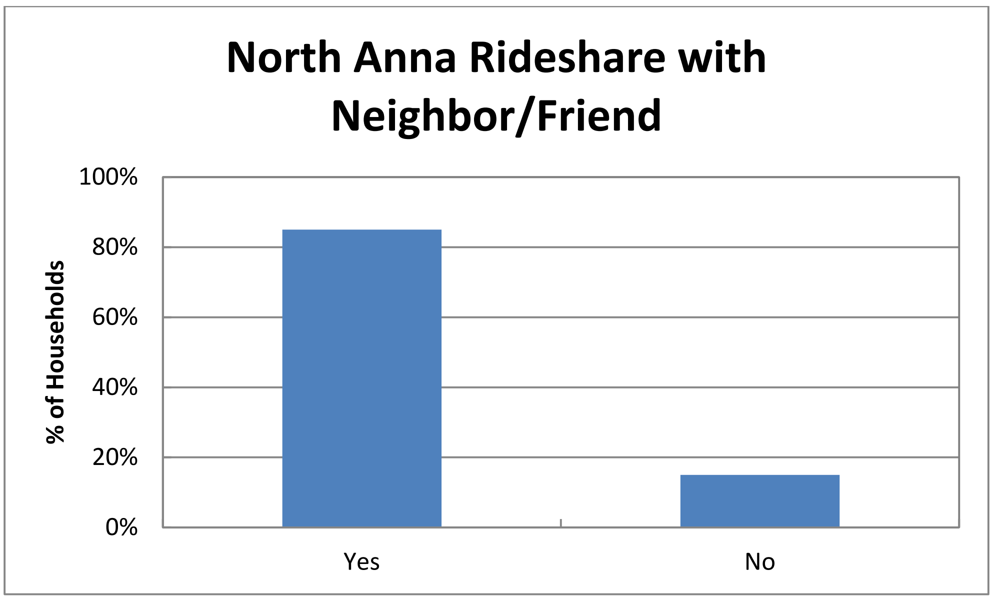


Figure F-5. Household Ridesharing Preference

Commuters

Figure F-6 presents the distribution of the number of commuters in each household. Commuters are defined as household members who travel to work or college on a daily basis. The data shows an average of 0.94 commuters in each household in the EPZ, and 59% of households have at least one commuter.

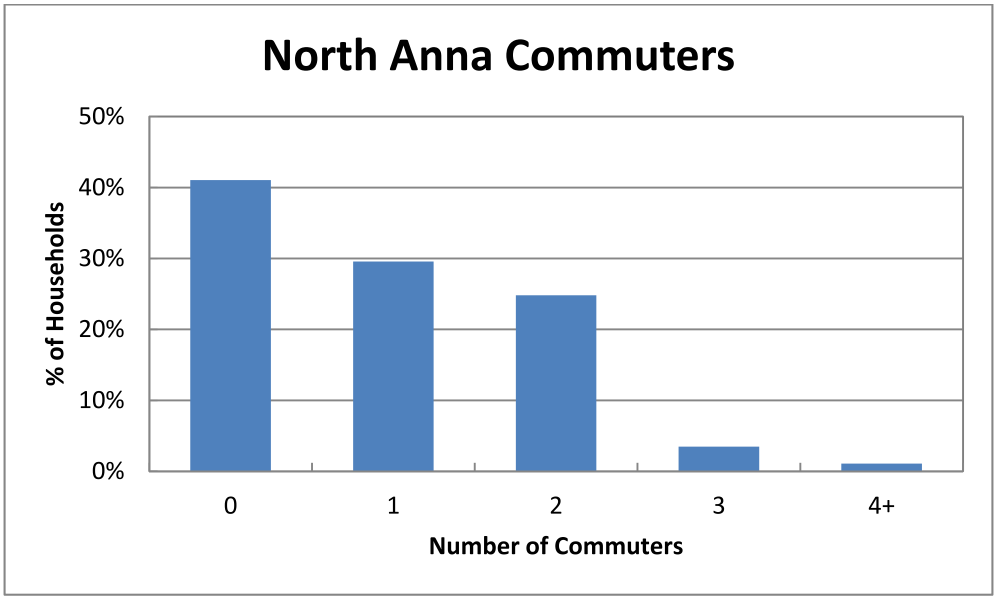


Figure F-6. Commuters in Households in the EPZ

Commuter Travel Modes

Figure F-7 presents the mode of travel that commuters use on a daily basis. The vast majority of commuters use their private automobiles to travel to work. The data shows an average of 1.04 employees per vehicle, assuming 2 people per vehicle – on average – for carpools.

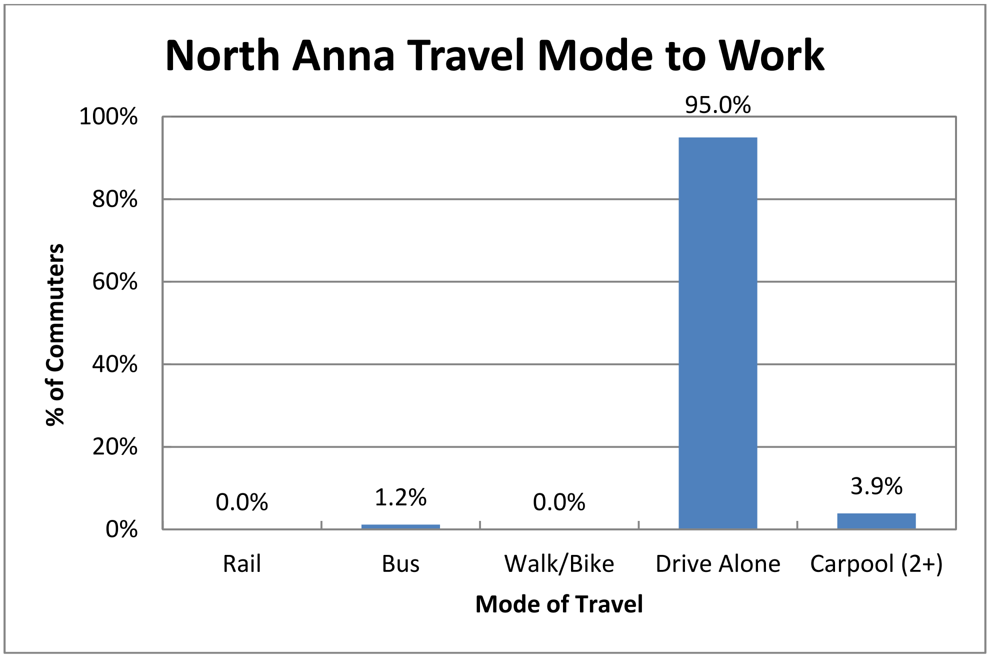


Figure F-7. Modes of Travel in the EPZ

F.3.2 Evacuation Response

Several questions were asked to gauge the population's response to an emergency. These are now discussed:

"How many of the vehicles would your household use during an evacuation?" The response is shown in Figure F-8. On average, evacuating households would use 1.42 vehicles.

"Would your family await the return of other family members prior to evacuating the area?" Of the survey participants who responded, 61 percent said they would await the return of other family members before evacuating and 39 percent indicated that they would not await the return of other family members.

"If you had a household pet, would you take your pet with you if you were asked to evacuate the area?" Based on the responses to the survey, 79 percent of households have a family pet. Of the households with pets, 83 percent of them indicated that they would take their pets with them, as shown in Figure F-9.

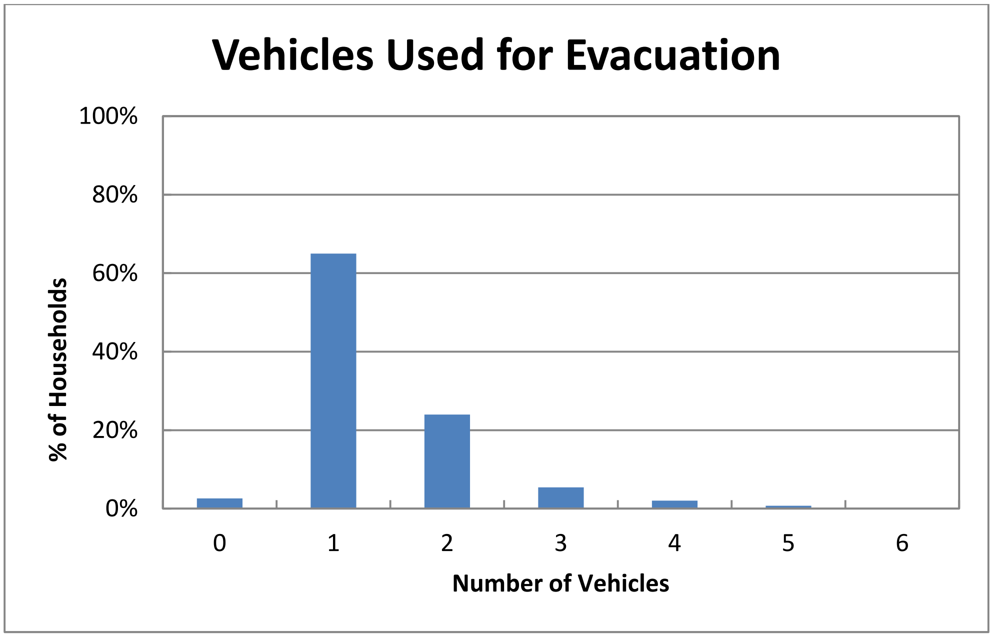


Figure F-8. Number of Vehicles Used for Evacuation

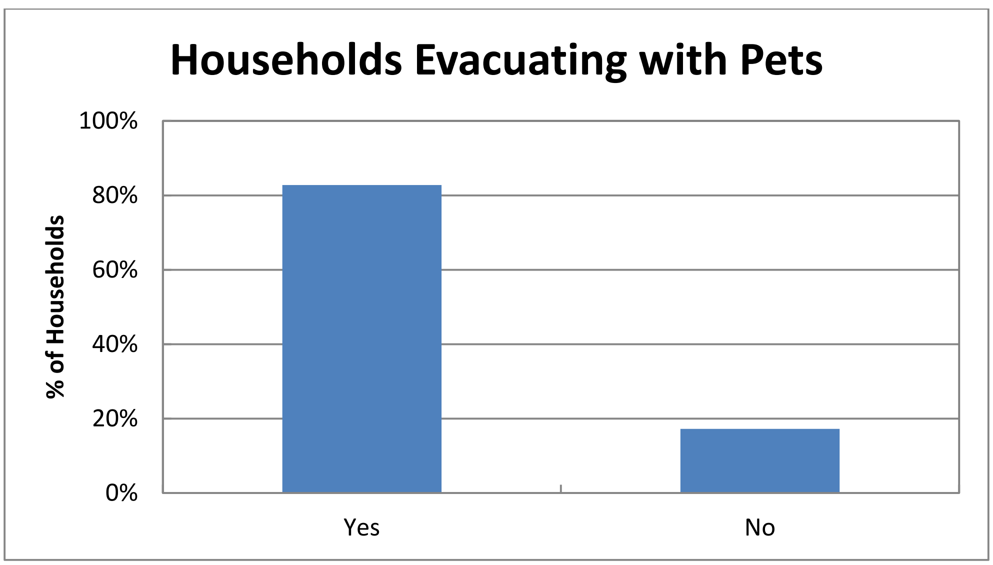


Figure F-9. Households Evacuating with Pets

"Emergency officials advise you to take shelter at home in an emergency. Would you?" This question is designed to elicit information regarding compliance with instructions to shelter in place. The results indicate that 81 percent of households who are advised to shelter in place would do so; the remaining 19 percent would choose to evacuate the area. Note the baseline ETE study assumes 20 percent of households will not comply with the shelter advisory, as per Section 2.5.2 of NUREG/CR-7002. Thus, the data obtained above is in good agreement with the federal guidance. The 2007 telephone survey did not include this question; these results are from the 2012 Surry Power Station telephone survey.

"Emergency officials advise you to take shelter at home now in an emergency and possibly evacuate later while people in other areas are advised to evacuate now. Would you?" This question is designed to elicit information specifically related to the possibility of a staged evacuation. That is, asking a population to shelter in place now and then to evacuate after a specified period of time. Results indicate that 74 percent of households would follow instructions and delay the start of evacuation until so advised, while the balance of 26 percent would choose to begin evacuating immediately. The 2007 telephone survey did not include this question; these results are from the 2012 Surry Power Station telephone survey.

F.3.3 Time Distribution Results

The survey asked several questions about the amount of time it takes to perform certain pre-evacuation activities. These activities involve actions taken by residents during the course of their day-to-day lives. Thus, the answers fall within the realm of the responder's experience.

The mobilization distributions provided below are the result of having applied the analysis described in Section 5.4.1 on the component activities of the mobilization.

"How long does it take the commuter to complete preparation for leaving work?" Figure F-10 presents the cumulative distribution; in all cases, the activity is completed by about 120 minutes. 86 percent can leave within 45 minutes.

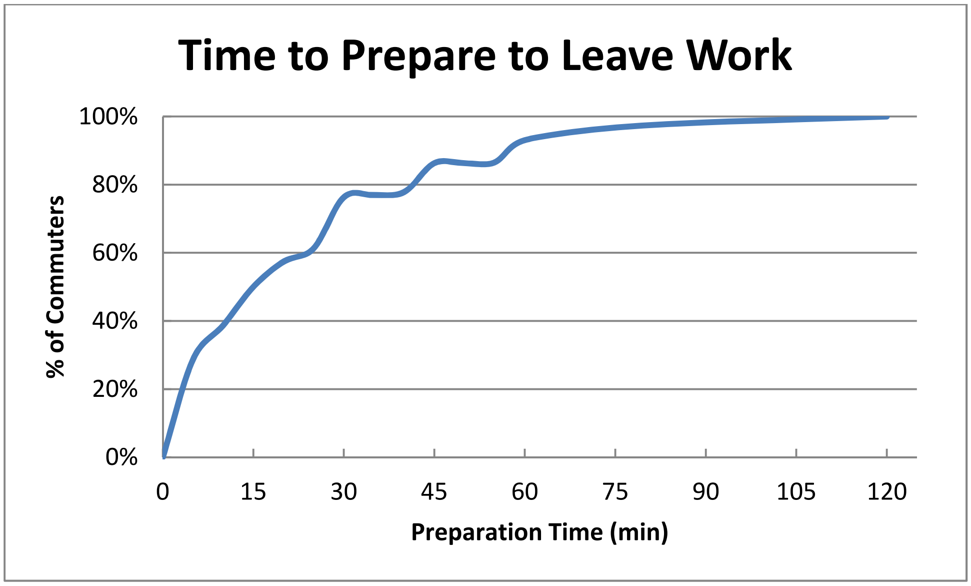


Figure F-10. Time Required to Prepare to Leave Work/School

"How long would it take the commuter to travel home?" Figure F-11 presents the work to home travel time for the EPZ. About 89 percent of commuters can arrive home within about 60 minutes of leaving work; all within 120 minutes.

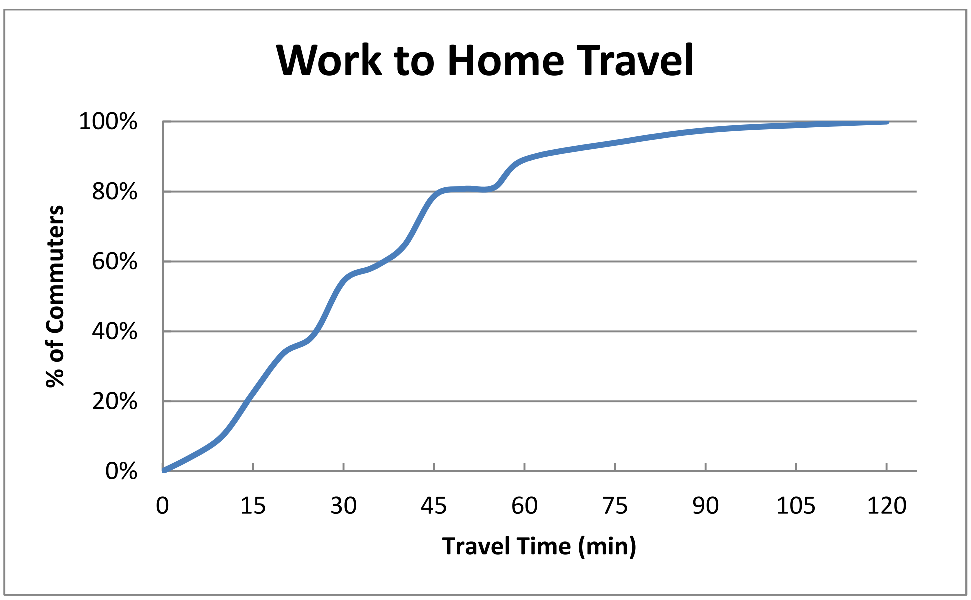


Figure F-11. Work to Home Travel Time

"How long would it take the family to pack clothing, secure the house, and load the car?" Figure F-12 presents the time required to prepare for leaving on an evacuation trip. In many ways this activity mimics a family's preparation for a short holiday or weekend away from home. Hence, the responses represent the experience of the responder in performing similar activities.

The distribution shown in Figure F-12 has a long "tail." About 91 percent of households can be ready to leave home within 75 minutes; the remaining households require up to an additional two hours.

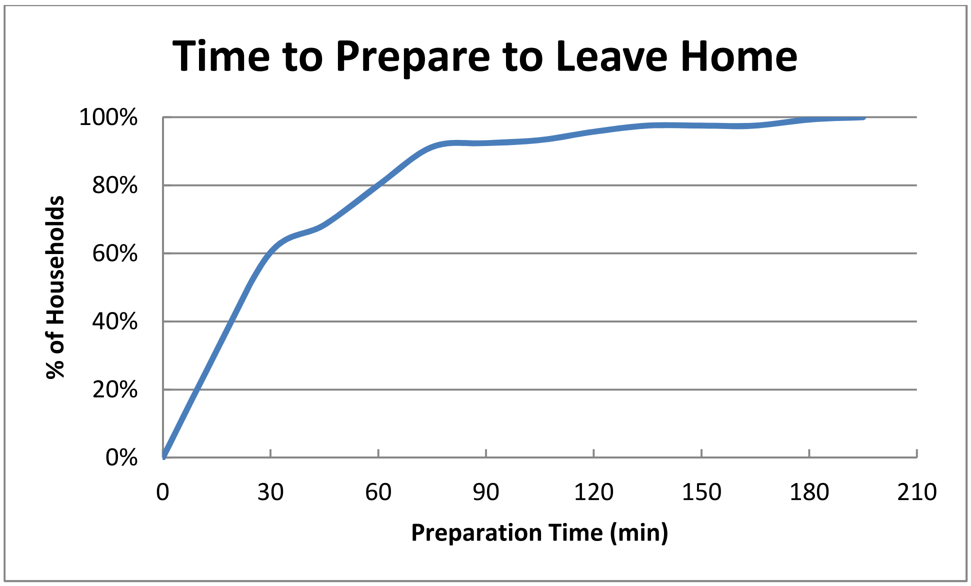


Figure F-12. Time to Prepare Home for Evacuation

"How long would it take you to clear 6 to 8 inches of snow from your driveway?" During adverse, snowy weather conditions, an additional activity must be performed before residents can depart on the evacuation trip. Although snow scenarios assume that the roads and highways have been plowed and are passable (albeit at lower speeds and capacities), it may be necessary to clear a private driveway prior to leaving the home so that the vehicle can access the street. Figure F-13 presents the time distribution for removing 6 to 8 inches of snow from a driveway. The time distribution for clearing the driveway has a long tail; about 91 percent of driveways are passable within 75 minutes. The last driveway is cleared three hours after the start of this activity. Note that those respondents (33%) who answered that they would not take time to clear their driveway were assumed to be ready immediately at the start of this activity. Essentially they would drive through the snow on the driveway to access the roadway and begin their evacuation trip.

The 2007 telephone survey did not include this question; these results are from the 2012 Surry Power Station telephone survey.

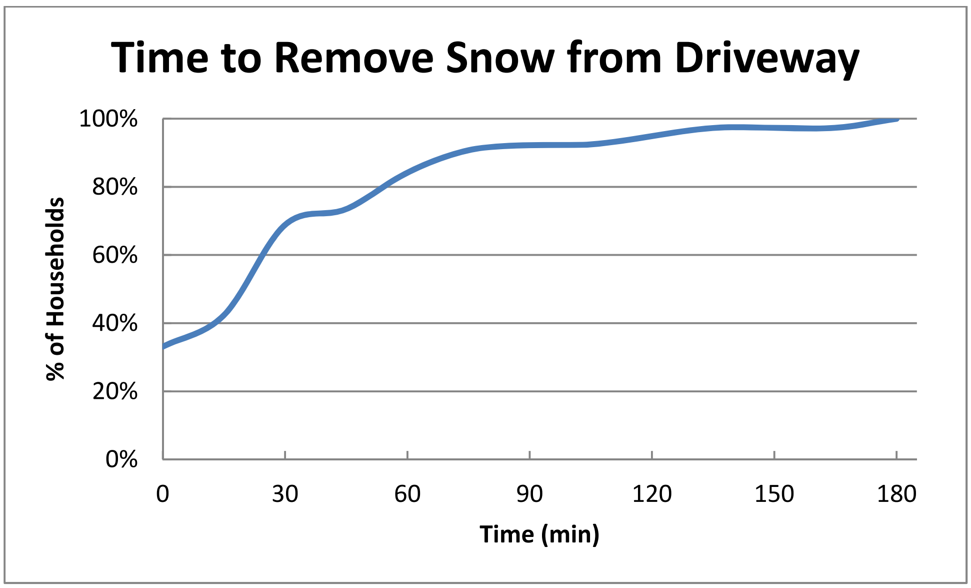


Figure F-13. Time to Clear Driveway of 6"-8" of Snow

F.4 Conclusions

The telephone survey provides valuable, relevant data associated with the EPZ population, which have been used to quantify demographics specific to the EPZ, and "mobilization time" which can influence evacuation time estimates.

ATTACHMENT A

Telephone Survey Instrument

Survey Instrument

Hello, my name is _______________ and I'm working on a survey being made for [insert marketing firm name] designed to identify local travel patterns in your area. The information obtained will be used in a traffic engineering study and in connection with an update of the county's emergency response plans. Your participation in this survey will greatly enhance the county's emergency preparedness program.

COL.1 Unused
COL.2 Unused
COL.3 Unused
COL.4 Unused
COL.5 Unused

Sex COL. 8
1 Male
2 Female

INTERVIEWER: ASK TO SPEAK TO THE HEAD OF HOUSEHOLD OR THE SPOUSE OF THE HEAD OF HOUSEHOLD. (Terminate call if not a residence)
IF ASKED FOR MORE INFORMATION ABOUT THE SURVEY, REFERENCE THE POSTCARD MAILED FROM KLD ASSOCIATES.

DO NOT ASK:

1. Record exchange number. To Be Determined

   COL. 9-11

---

2. In total, how many cars, or other vehicles are usually available to the household? (DO NOT READ ANSWERS.)

COL.12
1 ONE
2 TWO
3 THREE
4 FOUR
5 FIVE
6 SIX
7 SEVEN
8 EIGHT
9 NINE OR MORE
0 ZERO (NONE)
X REFUSED

---

3. How many people usually live in this household? (DO NOT READ ANSWERS.)

COL.13	COL.14
1 ONE	0 TEN
2 TWO	1 ELEVEN
3 THREE	2 TWELVE
4 FOUR	3 THIRTEEN
5 FIVE	4 FOURTEEN
6 SIX	5 FIFTEEN
7 SEVEN	6 SIXTEEN
8 EIGHT	7 SEVENTEEN
9 NINE	8 EIGHTEEN
	9 NINETEEN OR MORE
	X REFUSED

4. How many children living in this household go to local public, private, or parochial schools? (DO NOT READ ANSWERS.)

COL.15
0 ZERO
1 ONE
2 TWO
3 THREE
4 FOUR
5 FIVE
6 SIX
7 SEVEN
8 EIGHT
9 NINE OR MORE
X REFUSED

5. How many people in the household commute to a job, or to college, at least 4 times a week?

COL.16	SKIP TO
0 ZERO	Q. 11
1 ONE	Q. 6
2 TWO	Q. 6
3 THREE	Q. 6
4 FOUR OR MORE	Q. 6
5 DON'T KNOW/REFUSED	Q. 11

INTERVIEWER: For each person identified in Question 5, ask Questions 6, 7, 8, and 9.

6. Thinking about commuter #1, how does that person usually travel to work or college? (REPEAT QUESTION FOR EACH COMMUTER.)

	Commuter #1 COL.17	Commuter #2 COL.18	Commuter #3 COL.19	Commuter #4 COL.20
Rail	1	1	1	1
Bus	2	2	2	2
Walk/Bicycle	3	3	3	3
Driver Car/Van	4	4	4	4
Park & Ride (Car/Rail, Xpress_bus)	5	5	5	5
Driver Carpool-2 or more people	6	6	6	6
Passenger Carpool-2 or more people	7	7	7	7
Taxi	8	8	8	8
Refused	9	9	9	9

7. What is the name of the city, town or community in which Commuter #1 works or attends school? (REPEAT QUESTION FOR EACH COMMUTER.) (FILL IN ANSWER.)

COMMUTER #1			COMMUTER #2			COMMUTER #3			COMMUTER #4		
City/Town		State	City/Town		State	City/Town		State	City/Town		State
COL.21	COL.22	COL.23	COL.24	COL.25	COL.26	COL.27	COL.28	COL.29	COL.30	COL.31	COL.32
0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1
2	2	2	2	2	2	2	2	2	2	2	2
3	3	3	3	3	3	3	3	3	3	3	3
4	4	4	4	4	4	4	4	4	4	4	4
5	5	5	5	5	5	5	5	5	5	5	5
6	6	6	6	6	6	6	6	6	6	6	6
7	7	7	7	7	7	7	7	7	7	7	7
8	8	8	8	8	8	8	8	8	8	8	8
9	9	9	9	9	9	9	9	9	9	9	9

8. How long would it take Commuter #1 to travel home from work or college? (REPEAT QUESTION FOR EACH COMMUTER.) (DO NOT READ ANSWERS.)

COMMUTER #1

COL.33
1 5 MINUTES OR LESS
2 6-10 MINUTES
3 11-15 MINUTES
4 16-20 MINUTES
5 21-25 MINUTES
6 26-30 MINUTES
7 31-35 MINUTES
8 36-40 MINUTES
9 41-45 MINUTES

COL.34
1 46-50 MINUTES
2 51-55 MINUTES
3 56 - 1 HOUR
4 OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5 BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6 BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7 BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8 OVER 2 HOURS (SPECIFY _____)
9
0
X DON'T KNOW/REFUSED

COMMUTER #2

COL.35
1 5 MINUTES OR LESS
2 6-10 MINUTES
3 11-15 MINUTES
4 16-20 MINUTES
5 21-25 MINUTES
6 26-30 MINUTES
7 31-35 MINUTES
8 36-40 MINUTES
9 41-45 MINUTES

COL.36
1 46-50 MINUTES
2 51-55 MINUTES
3 56 - 1 HOUR
4 OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5 BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6 BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7 BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8 OVER 2 HOURS (SPECIFY _____)
9
0
X DON'T KNOW/REFUSED

COMMUTER #3

COL.37
1 5 MINUTES OR LESS
2 6-10 MINUTES
3 11-15 MINUTES
4 16-20 MINUTES
5 21-25 MINUTES
6 26-30 MINUTES
7 31-35 MINUTES
8 36-40 MINUTES
9 41-45 MINUTES

COL.38
1 46-50 MINUTES
2 51-55 MINUTES
3 56 - 1 HOUR
4 OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5 BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6 BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7 BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8 OVER 2 HOURS (SPECIFY _____)
9
0
X DON'T KNOW/REFUSED

COMMUTER #4

COL.39
1 5 MINUTES OR LESS
2 6-10 MINUTES
3 11-15 MINUTES
4 16-20 MINUTES
5 21-25 MINUTES
6 26-30 MINUTES
7 31-35 MINUTES
8 36-40 MINUTES
9 41-45 MINUTES

COL.40
1 46-50 MINUTES
2 51-55 MINUTES
3 56 - 1 HOUR
4 OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5 BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6 BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7 BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8 OVER 2 HOURS (SPECIFY _____)
9
0
X DON'T KNOW/REFUSED

9. Approximately how long does it take Commuter #1 to complete preparation for leaving work or college prior to starting the trip home? (REPEAT QUESTION FOR EACH COMMUTER.)
(DO NOT READ ANSWERS.)

COMMUTER #1

COL. 41		COL. 42	
1	5 MINUTES OR LESS	1	46-50 MINUTES
2	6-10 MINUTES	2	51-55 MINUTES
3	11-15 MINUTES	3	56 - 1 HOUR
4	16-20 MINUTES	4	OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5	21-25 MINUTES	5	BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6	26-30 MINUTES	6	BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7	31-35 MINUTES	7	BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8	36-40 MINUTES	8	OVER 2 HOURS (SPECIFY _____)
9	41-45 MINUTES	9	
		0	
		X	DON'T KNOW/REFUSED

COMMUTER #2

COL. 43		COL. 44	
1	5 MINUTES OR LESS	1	46-50 MINUTES
2	6-10 MINUTES	2	51-55 MINUTES
3	11-15 MINUTES	3	56 - 1 HOUR
4	16-20 MINUTES	4	OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5	21-25 MINUTES	5	BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6	26-30 MINUTES	6	BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7	31-35 MINUTES	7	BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8	36-40 MINUTES	8	OVER 2 HOURS (SPECIFY _____)
9	41-45 MINUTES	9	
		0	
		X	DON'T KNOW/REFUSED

COMMUTER #3

COL. 45		COL. 46	
1	5 MINUTES OR LESS	1	46-50 MINUTES
2	6-10 MINUTES	2	51-55 MINUTES
3	11-15 MINUTES	3	56 - 1 HOUR
4	16-20 MINUTES	4	OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5	21-25 MINUTES	5	BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6	26-30 MINUTES	6	BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7	31-35 MINUTES	7	BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8	36-40 MINUTES	8	OVER 2 HOURS (SPECIFY _____)
9	41-45 MINUTES	9	
		0	
		X	DON'T KNOW/REFUSED

COMMUTER #4

COL. 47		COL. 48	
1	5 MINUTES OR LESS	1	46-50 MINUTES
2	6-10 MINUTES	2	51-55 MINUTES
3	11-15 MINUTES	3	56 - 1 HOUR
4	16-20 MINUTES	4	OVER 1 HOUR, BUT LESS THAN 1 HOUR 15 MINUTES
5	21-25 MINUTES	5	BETWEEN 1 HOUR 16 MINUTES AND 1 HOUR 30 MINUTES
6	26-30 MINUTES	6	BETWEEN 1 HOUR 31 MINUTES AND 1 HOUR 45 MINUTES
7	31-35 MINUTES	7	BETWEEN 1 HOUR 46 MINUTES AND 2 HOURS
8	36-40 MINUTES	8	OVER 2 HOURS (SPECIFY _____)
9	41-45 MINUTES	9	
		0	
		X	DON'T KNOW/REFUSED

10. When the commuters are away from home, is there a vehicle at home that is available for evacuation during any emergency?

Col. 49
1 Yes
2 No
3 Don't Know/Refused

11. Would you await the return of family members prior to evacuating the area?

Col. 50
1 Yes
2 No
3 Don't Know/Refused

12. How many of the vehicles that are usually available to the household would your family use during an evacuation? (DO NOT READ ANSWERS.)

COL.51
1 ONE
2 TWO
3 THREE
4 FOUR
5 FIVE
6 SIX
7 SEVEN
8 EIGHT
9 NINE OR MORE
0 ZERO (NONE)
X REFUSED

13. How long would it take the family to pack clothing, secure the house, load the car, and complete preparations prior to evacuating the area? (DO NOT READ ANSWERS.)

COL.52
1 LESS THAN 15 MINUTES
2 15-30 MINUTES
3 31-45 MINUTES
4 46 MINUTES - 1 HOUR
5 1 HOUR TO 1 HOUR 15 MINUTES
6 1 HOUR 16 MINUTES TO 1 HOUR 30 MINUTES
7 1 HOUR 31 MINUTES TO 1 HOUR 45 MINUTES
8 1 HOUR 46 MINUTES TO 2 HOURS
9 2 HOURS TO 2 HOURS 15 MINUTES
0 2 HOURS 16 MINUTES TO 2 HOURS 30 MINUTES
X 2 HOURS 31 MINUTES TO 2 HOURS 45 MINUTES
Y 2 HOURS 46 MINUTES TO 3 HOURS

COL.53
1 3 HOURS TO 3 HOURS 15 MINUTES
2 3 HOURS 16 MINUTES TO 3 HOURS 30 MINUTES
3 3 HOURS 31 MINUTES TO 3 HOURS 45 MINUTES
4 3 HOURS 46 MINUTES TO 4 HOURS
5 4 HOURS TO 4 HOURS 15 MINUTES
6 4 HOURS 16 MINUTES TO 4 HOURS 30 MINUTES
7 4 HOURS 31 MINUTES TO 4 HOURS 45 MINUTES
8 4 HOURS 46 MINUTES TO 5 HOURS
9 5 HOURS TO 5 HOURS 15 MINUTES
0 5 HOURS 16 MINUTES TO 5 HOURS 30 MINUTES
X 5 HOURS 31 MINUTES TO 5 HOURS 45 MINUTES
Y 5 HOURS 46 MINUTES TO 6 HOURS

COL.54
1 DON'T KNOW

14. Would you take household pets with you if you were asked to evacuate the area?

Col. 58	
1	Yes
2	No
3	Don't Know/Refused

Thank you very much. ____
(TELEPHONE NUMBER CALLED)

For Additional information: If requested, **ask what county they reside in** and provide the appropriate number from the list below:

Contact your County Emergency Management Office:

COUNTY	**PHONE NUMBER**
Caroline	(804)633-4357
Hanover	(804)365-6140
Louisa	(540)967-1234
Orange	(540)672-1235
Spotsylvania	(540)582-7115

APPENDIX G

Traffic Management Plan

G. TRAFFIC MANAGEMENT PLAN

NUREG/CR-7002 indicates that the existing traffic control points (TCP) and access control points (ACP) identified by the offsite agencies should be used in the evacuation simulation modeling. The traffic and access control plans for the EPZ were provided by each county.

These plans were reviewed and the TCP were modeled accordingly.

G.1 Traffic Control Points

As discussed in Section 9, traffic control points at intersections (which are controlled) are modeled as actuated signals. If an intersection has a pre-timed signal, stop, or yield control, and the intersection is identified as a traffic control point, the control type was changed to an actuated signal in the DYNEV II system. Table K-2 provides the control type and node number for those nodes which are controlled. If the existing control was changed due to the point being a Traffic Control Point, the control type is indicated as a TCP in Table K-2.

Figure G-1 maps the TCP identified in the county emergency plans for a full EPZ evacuation. Theses TCP would be manned during evacuation by traffic guides who would direct evacuees in the proper direction and facilitate the flow of traffic through the intersections.

G.2 Access Control Points

It is assumed that ACP will be established within 2 hours of the advisory to evacuate to discourage through travelers from using major through routes which traverse the study area. As discussed in Section 3.7, external traffic was only considered on three routes which traverse the study area – Interstate-95, Interstate-64 and US-1 – in this analysis. The generation of these external trips ceased at 2 hours after the advisory to evacuate in the simulation.

Figure G-2 maps the ACP identified in the county emergency plans which would be in affect during the evacuation of the full EPZ. These ACP are concentrated on roadways giving access to the EPZ. Theses ACP would be manned during an evacuation by traffic guides who would direct evacuees in the proper direction away from NAPS and facilitate the flow of traffic through the intersections.

This study did not identify any additional intersections that should be identified as TCP or ACP.

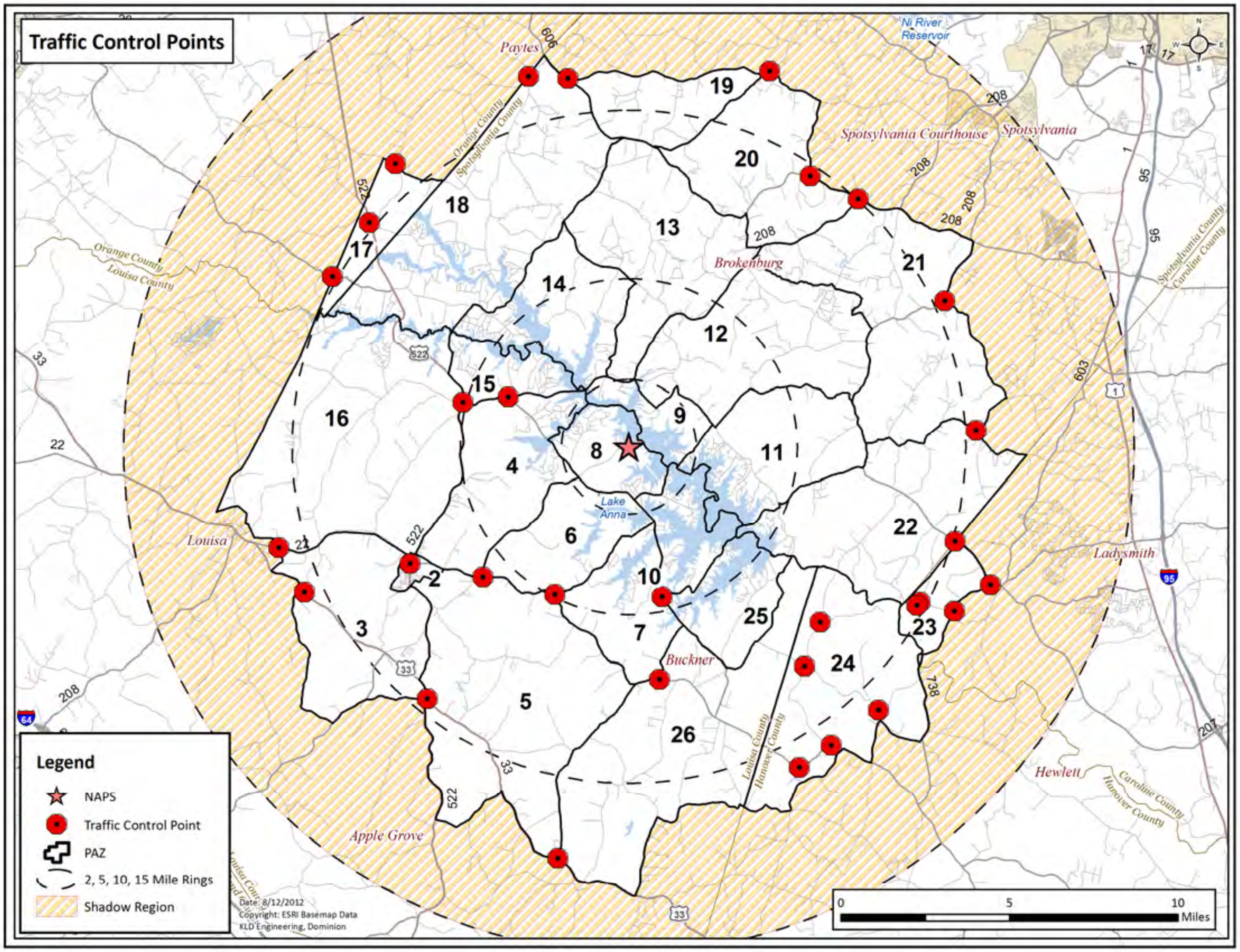


Figure G-1. Traffic Control Points for the NAPS Site

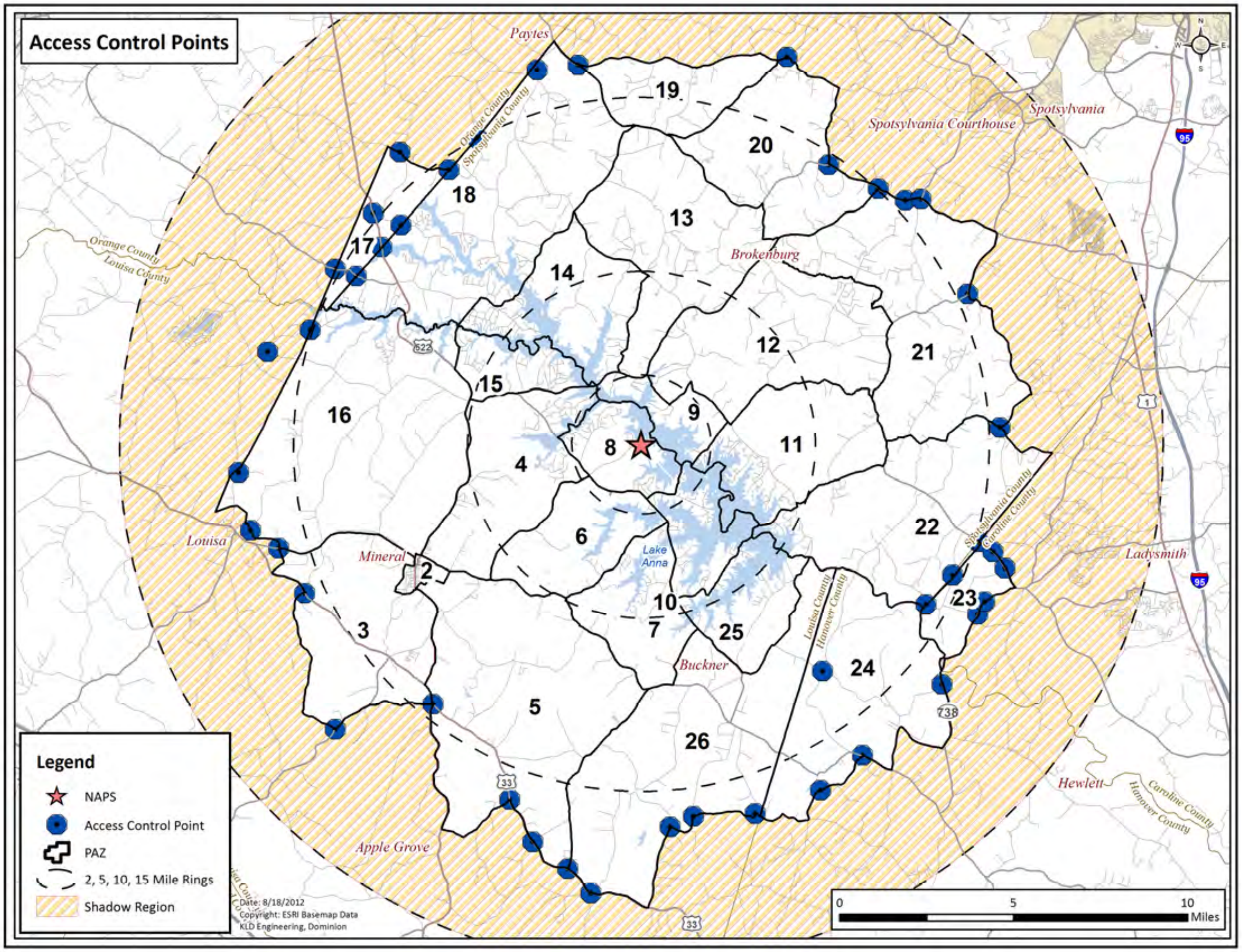


Figure G-2. Access Control Points for the NAPS Site

APPENDIX H

Evacuation Regions

H EVACUATION REGIONS

This appendix presents the evacuation percentages for each Evacuation Region (Table H-1) and maps of all Evacuation Regions. The percentages presented in Table H-1 are based on the methodology discussed in assumption 5 of Section 2.2 and shown in Figure 2-1.

Note the baseline ETE study assumes 20 percent of households will not comply with the shelter advisory, as per Section 2.5.2 of NUREG/CR-7002.

Table H-1. Percent of PAZ Population Evacuating for Each Region

Basic Regions

Region	Description	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R01	2-Mile Radius	2-Mile Radius	20%	20%	20%	20%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R02	5-Mile Radius	5-Mile Radius	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R03	Full EPZ	Full EPZ	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Evacuate 2-Mile Radius and Downwind to 5 Miles

Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R04	N, NNE	349° - 33°	20%	20%	20%	20%	100%	20%	100%	100%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R05	NE	34° - 56°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R06	ENE, E	57° - 101°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R07	ESE	102° - 123°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R08	SE	124° - 146°	20%	20%	20%	20%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R09	SSE, S	147° - 191°	20%	20%	20%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R10	SSW	192° - 213°	20%	20%	20%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R11	SW	214° - 236°	20%	20%	100%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R12	WSW	237° - 258°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R13	W	259°- 281°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	20%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R14	WNW, NW	282° - 326°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R15	NNW	327° - 349°	20%	20%	20%	20%	100%	20%	100%	100%	100%	20%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%

Evacuate 5-Mile Radius and Downwind to the EPZ Boundary

Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R16	N	349° - 11°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	100%	100%	100%	20%	20%	20%	20%	100%	20%
R17	NNE	12° - 33°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	100%	100%	100%	100%	20%	20%	20%	100%	20%
R18	NE	34° - 56°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	100%	100%	100%	20%	20%	20%	100%	20%
R19	ENE	57° - 78°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	100%	100%	100%	20%	20%	100%	20%
R20	E	79° - 101°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	100%	100%	100%	20%	100%	20%
R21	ESE	102° - 123°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	100%	100%	100%	100%	100%	100%
R22	SE	124° - 146°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	100%	100%	100%	100%	100%
R23	SSE, S	147° - 191°	20%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	100%	100%	100%
R24	SSW	192° - 213°	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	100%
R25	SW, WSW	214° - 258°	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R26	W	259° - 281°	100%	100%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	100%	20%
R27	WNW, NW	282° - 326°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	100%	20%
R28	NNW	327° - 349°	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	100%	20%

Table H-2. Percent of PAZ Population Evacuating for Each Staged Region

Staged Evacuation - 2-Mile Radius Evacuates, then Evacuate Downwind to 5 Miles																											
Region	Wind Direction Toward:	Site PAR Description	Protection Action Zone (PAZ)																								
			2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
R29	-	5-Mile Radius	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R30	N, NNE	349° - 33°	20%	20%	20%	20%	100%	20%	100%	100%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R31	NE	34° - 56°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R32	ENE, E	57° - 101°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R33	ESE	102° - 123°	20%	20%	20%	20%	100%	20%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R34	SE	124° - 146°	20%	20%	20%	20%	100%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R35	SSE, S	147° - 191°	20%	20%	20%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	100%	20%
R36	SSW	192° - 213°	20%	20%	20%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R37	SW	214° - 236°	20%	20%	100%	20%	100%	100%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R38	WSW	237° - 258°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R39	W	259°- 281°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	20%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R40	WNW, NW	282° - 326°	20%	20%	100%	20%	100%	20%	100%	100%	100%	20%	20%	20%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
R41	NNW	327° - 349°	20%	20%	20%	20%	100%	20%	100%	100%	100%	20%	20%	100%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Shelter-in-Place until 90% ETE for R01, then Evacuate[1]					PAZ(s) Shelter-in-Place												PAZ(s) Evacuate										

[1] 20% of population in these PAZ will not comply with the shelter advisory, as per Section 2.5.2 of NUREG/CR-7002. Once 90% of the 2-Mile Region has evacuated, the remaining population in these PAZ will evacuate.

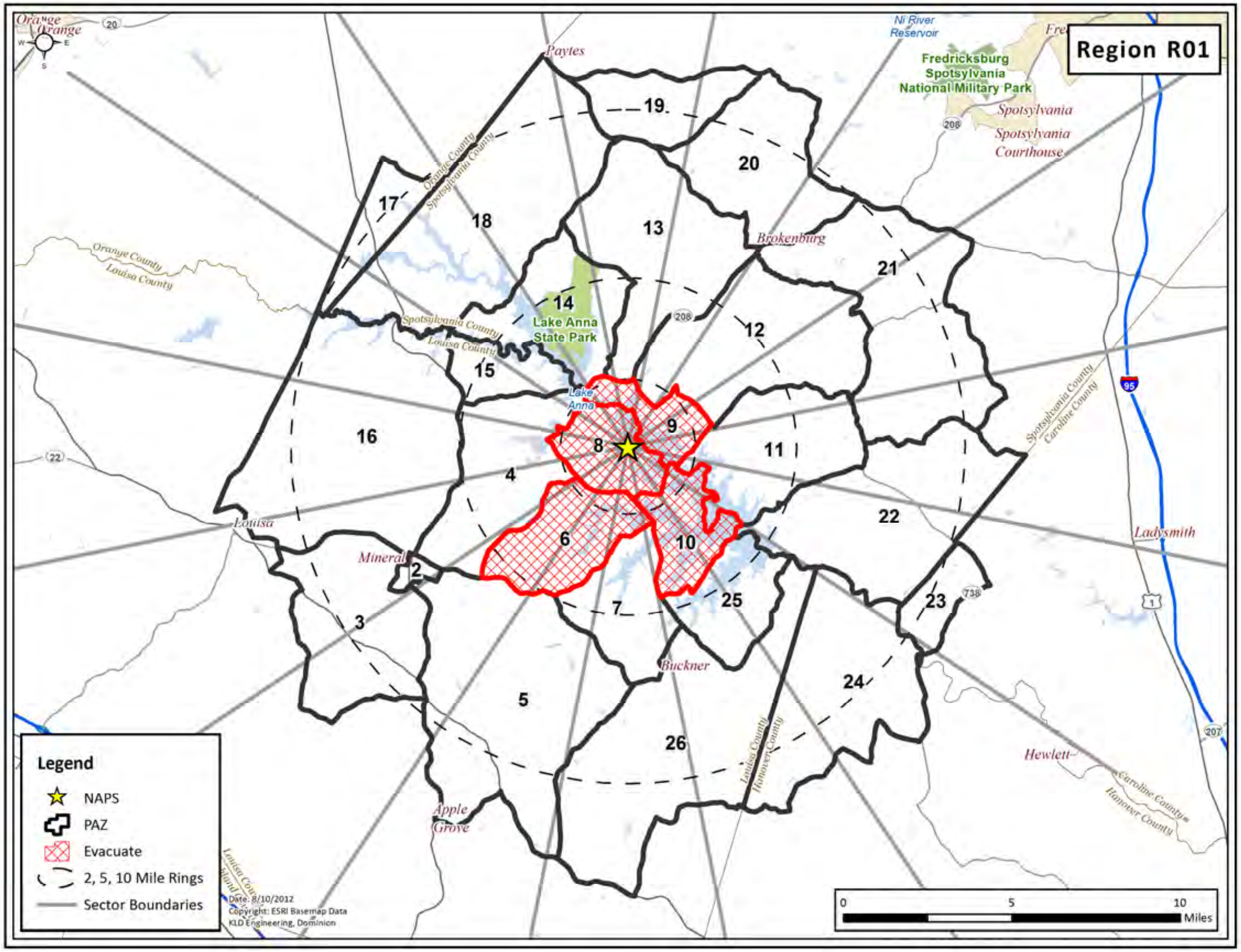


Figure H-1. Region R01

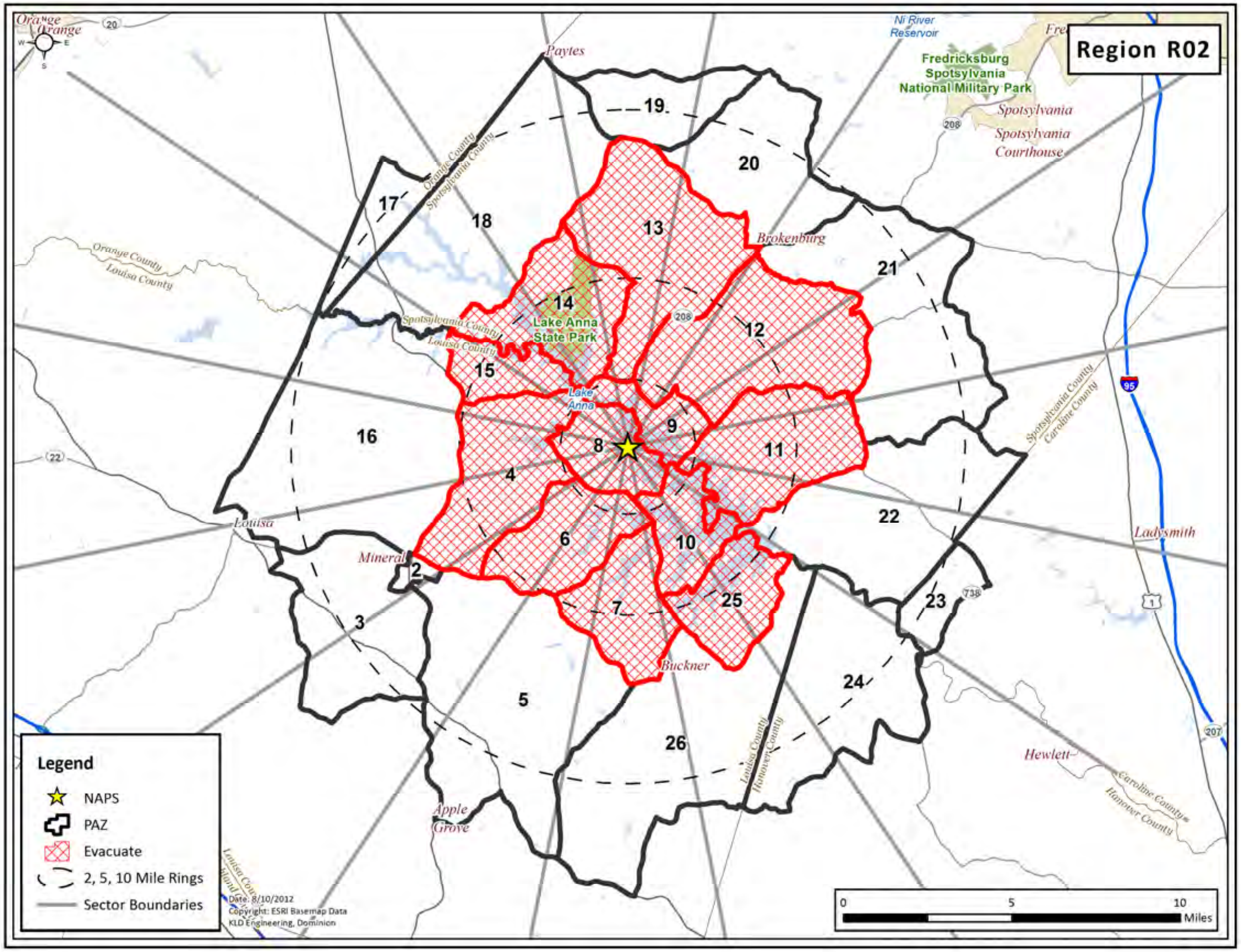


Figure H-2. Region R02

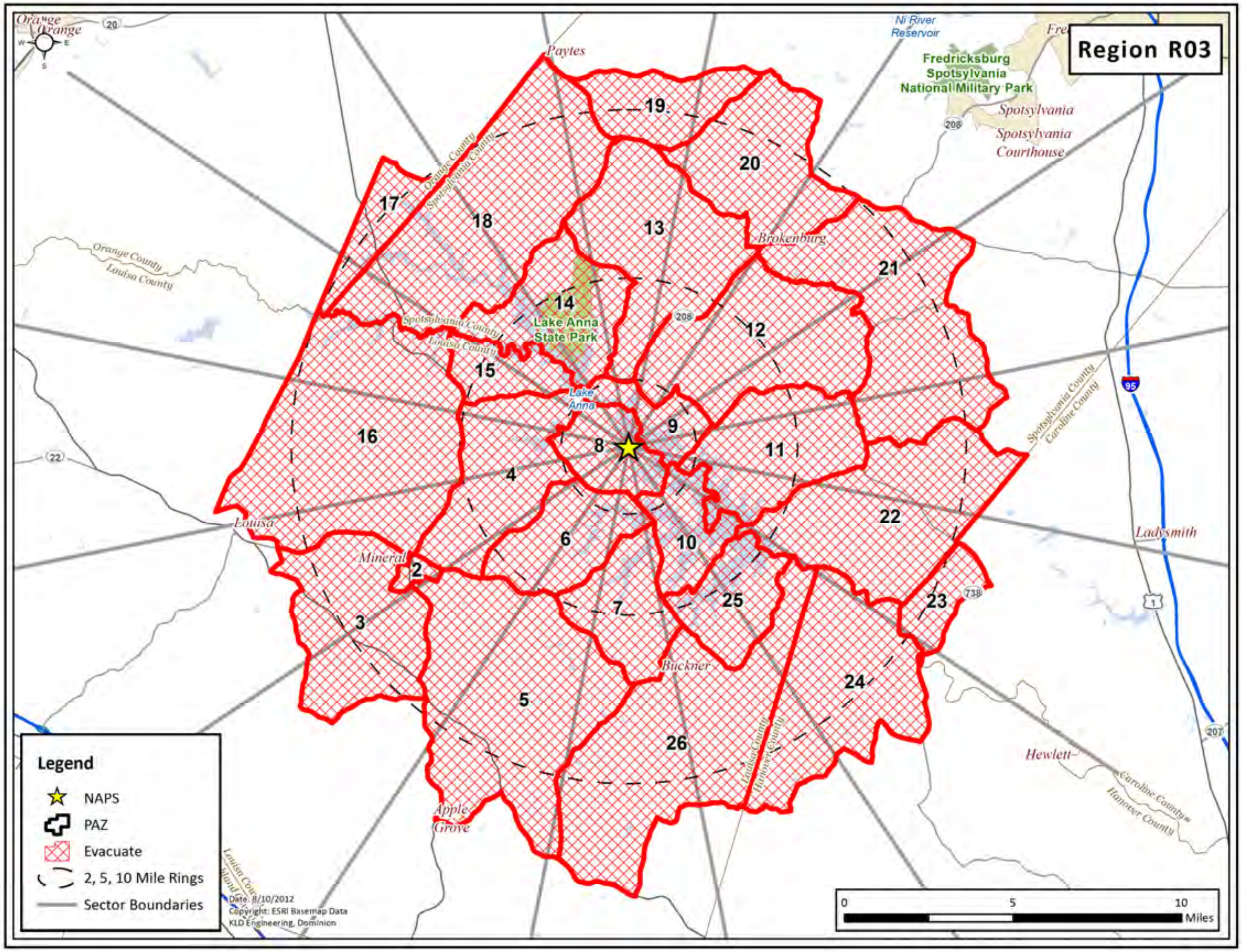


Figure H-3. Region R03

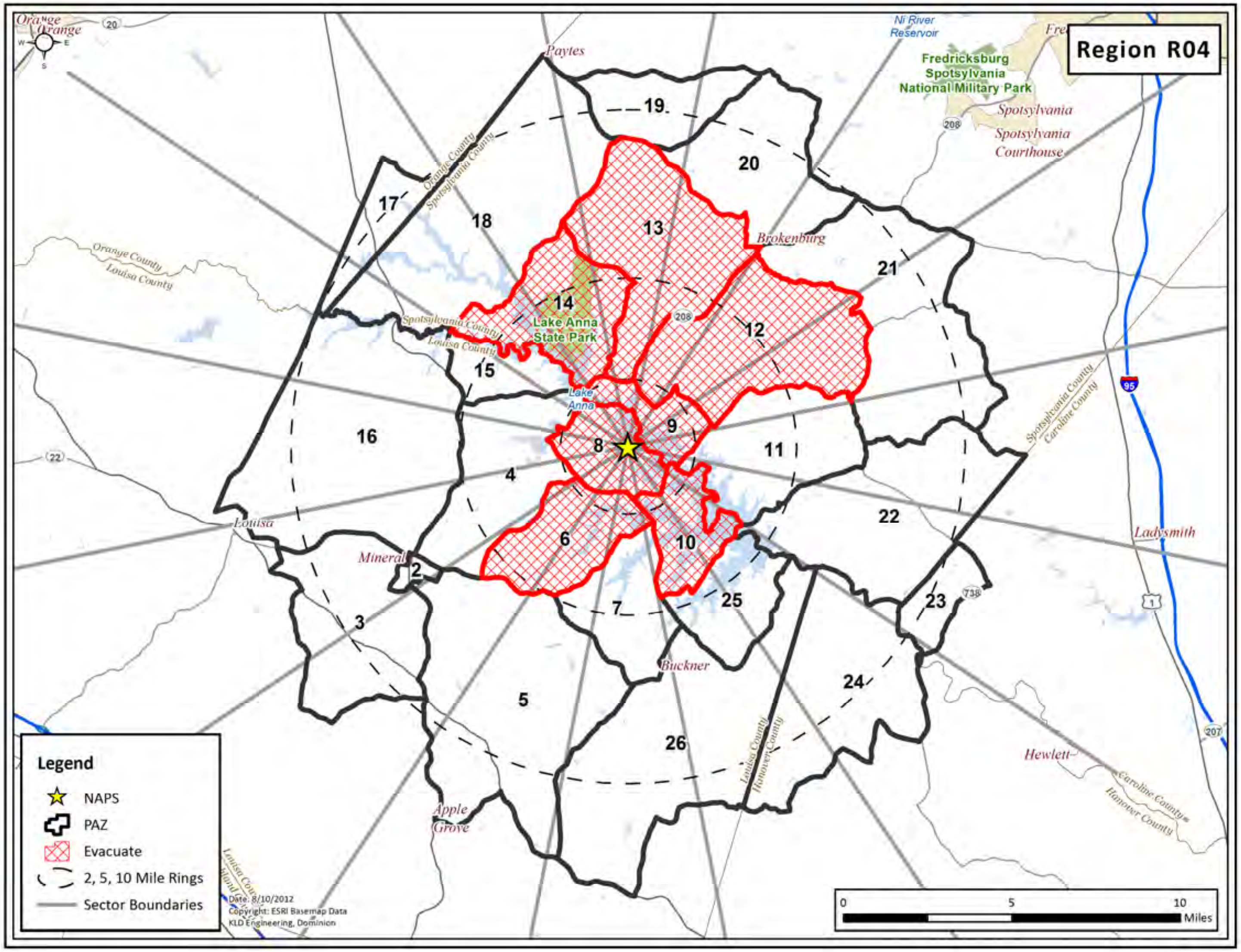


Figure H-4. Region R04

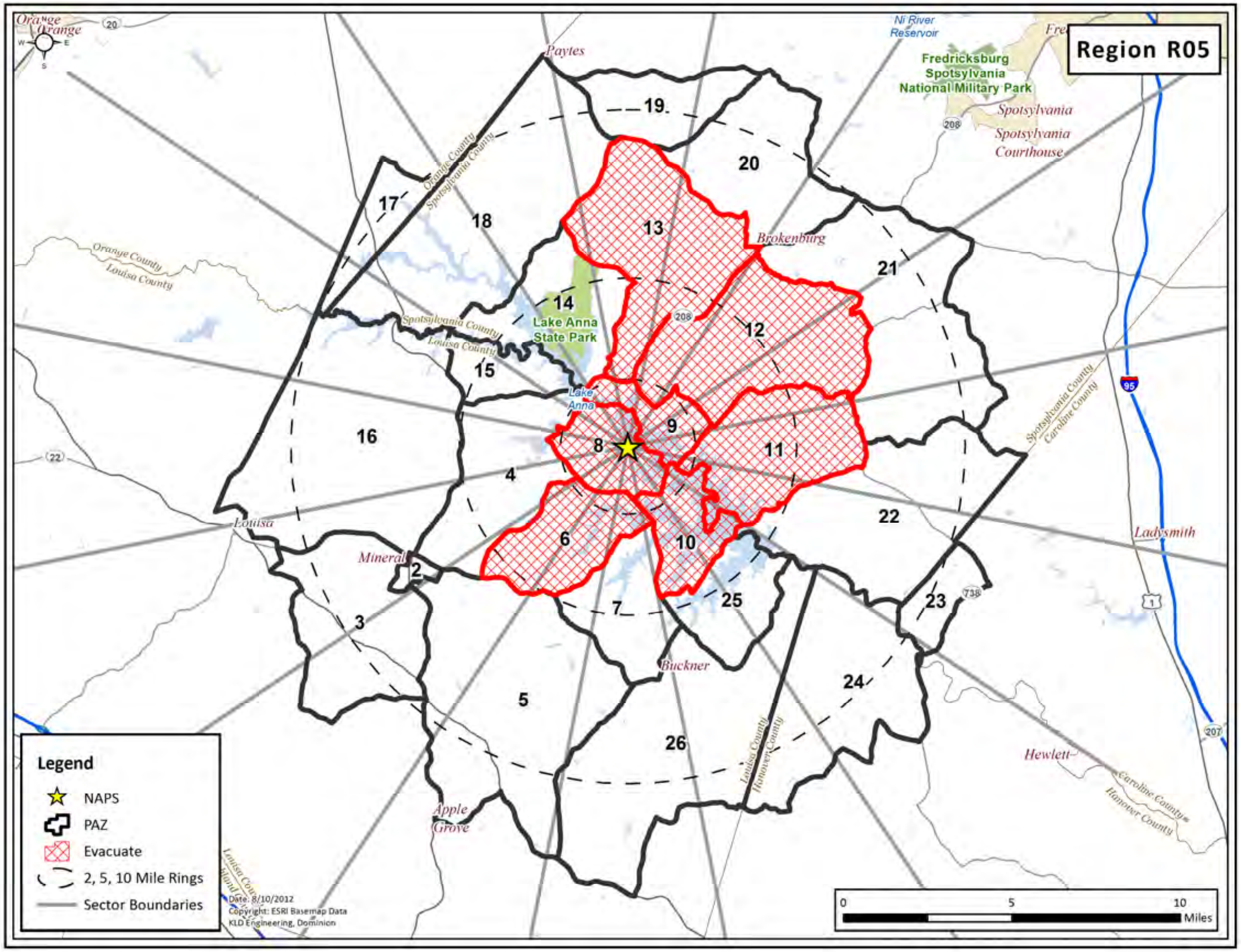


Figure H-5. Region R05

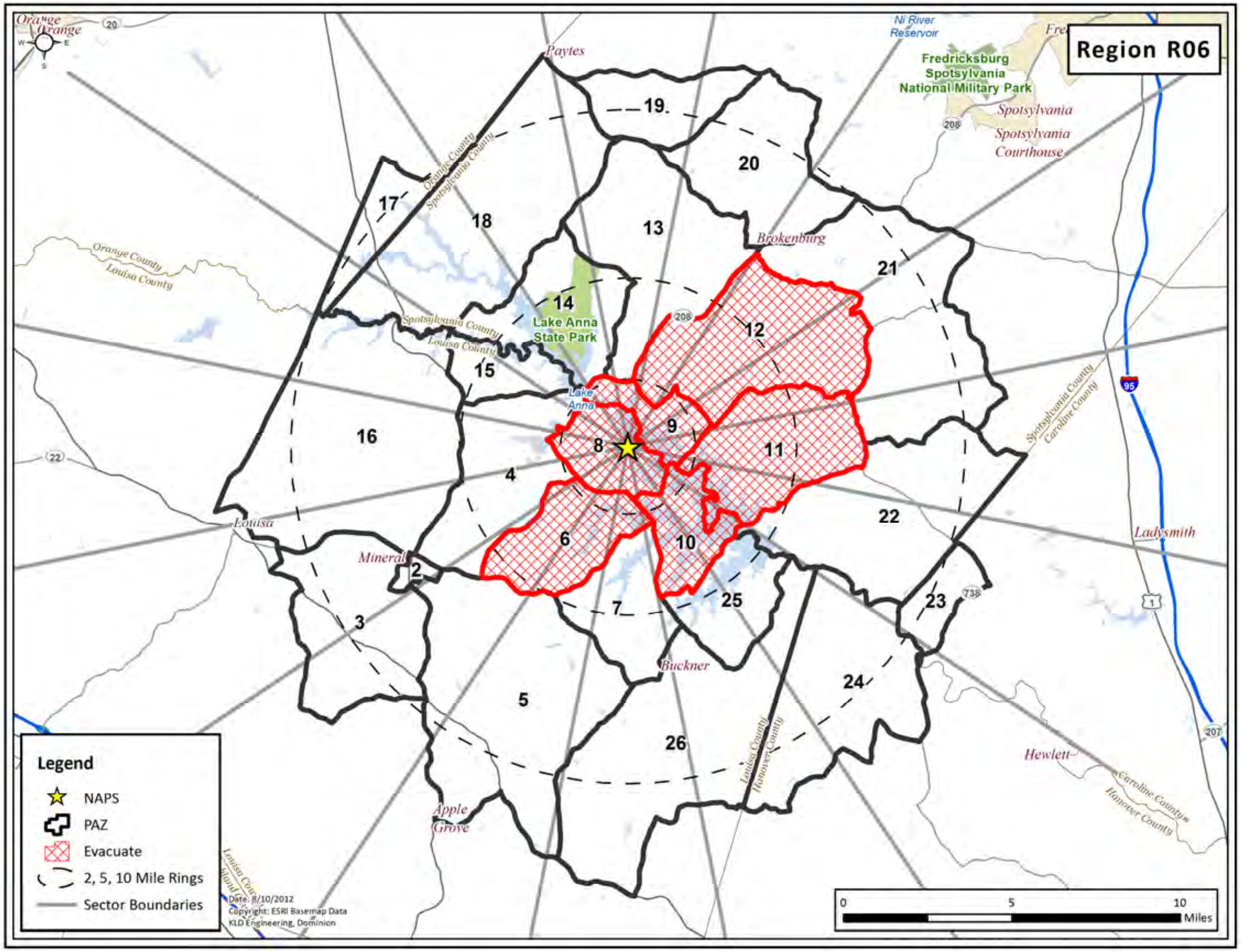


Figure H-6. Region R06

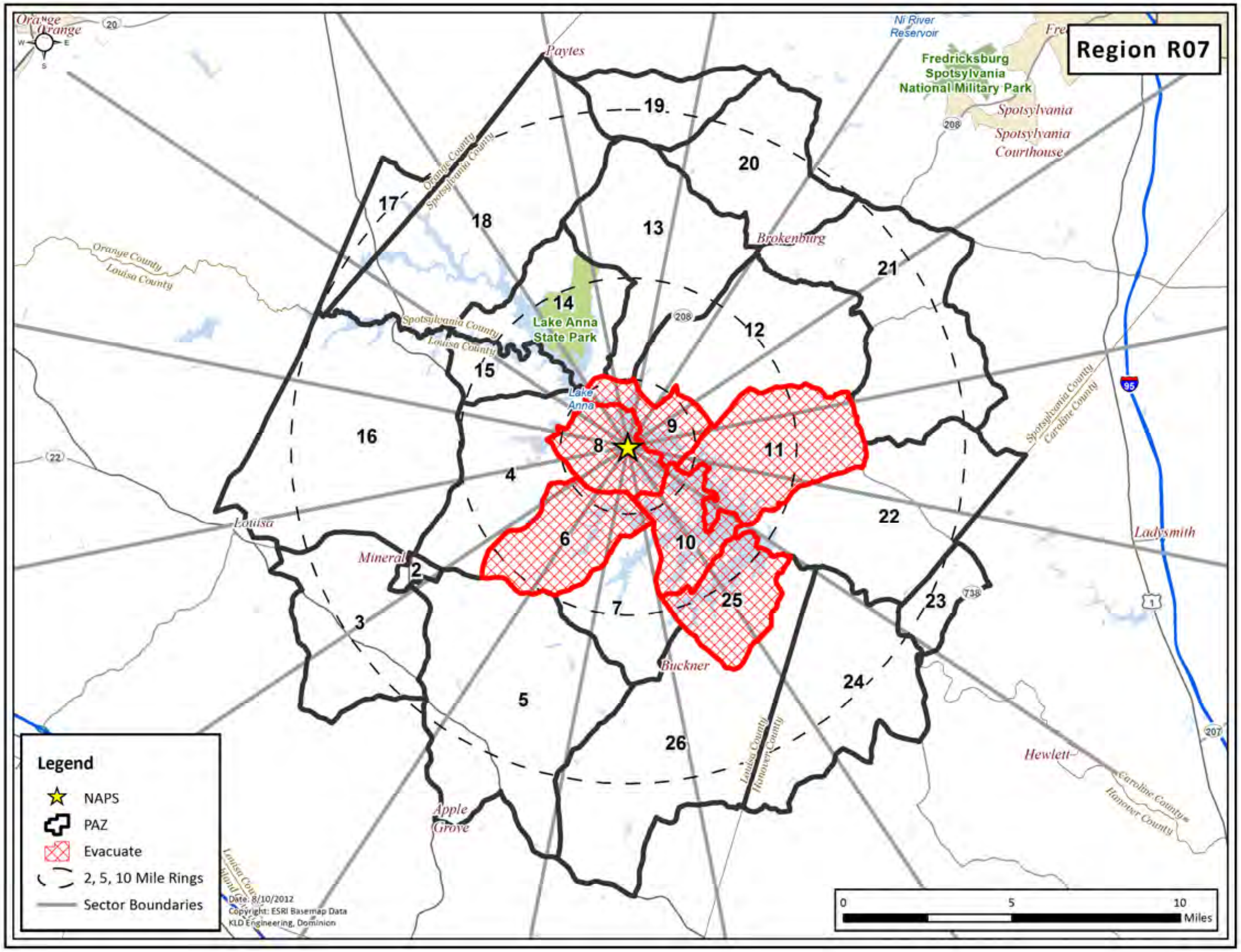


Figure H-7. Region R07

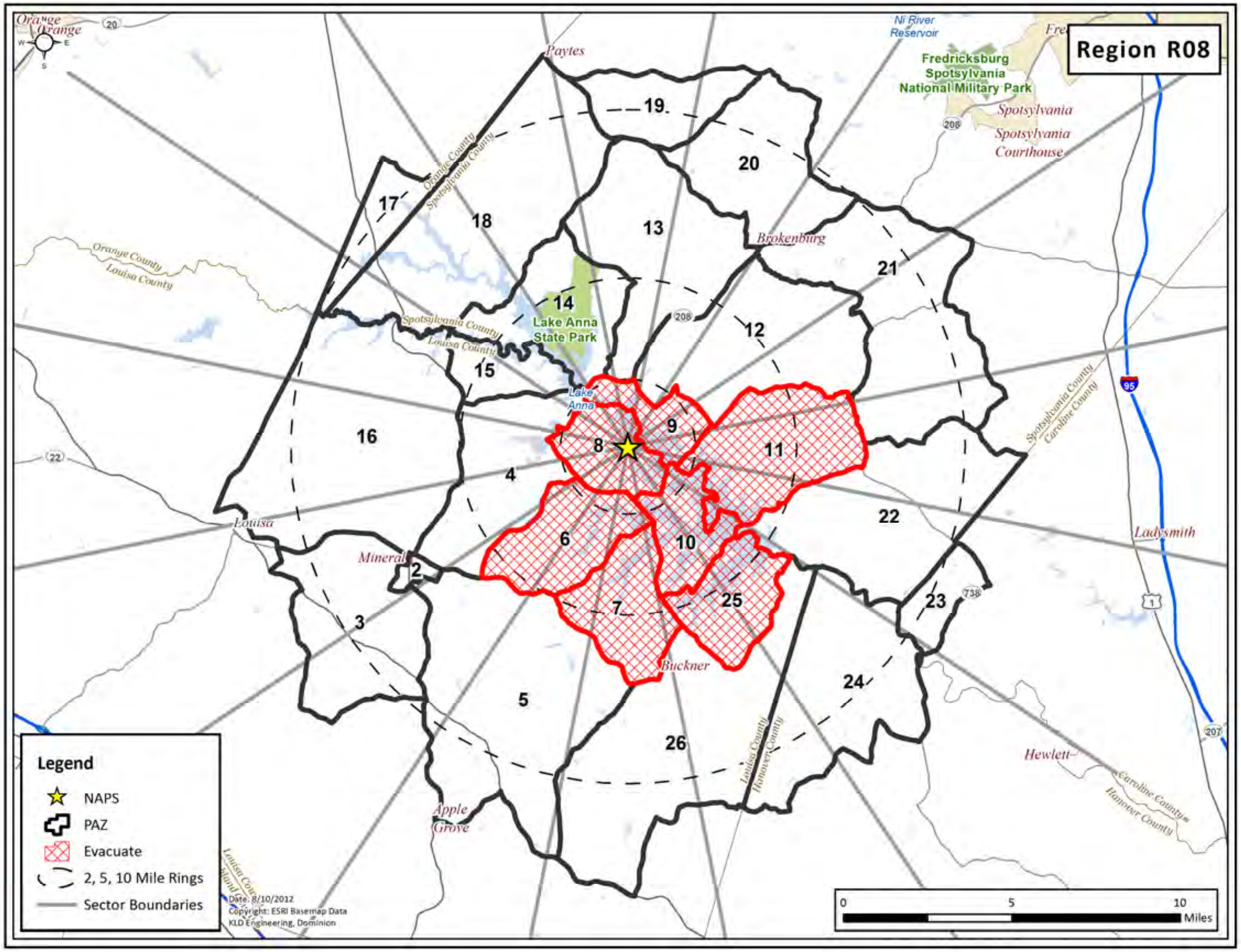


Figure H-8. Region R08

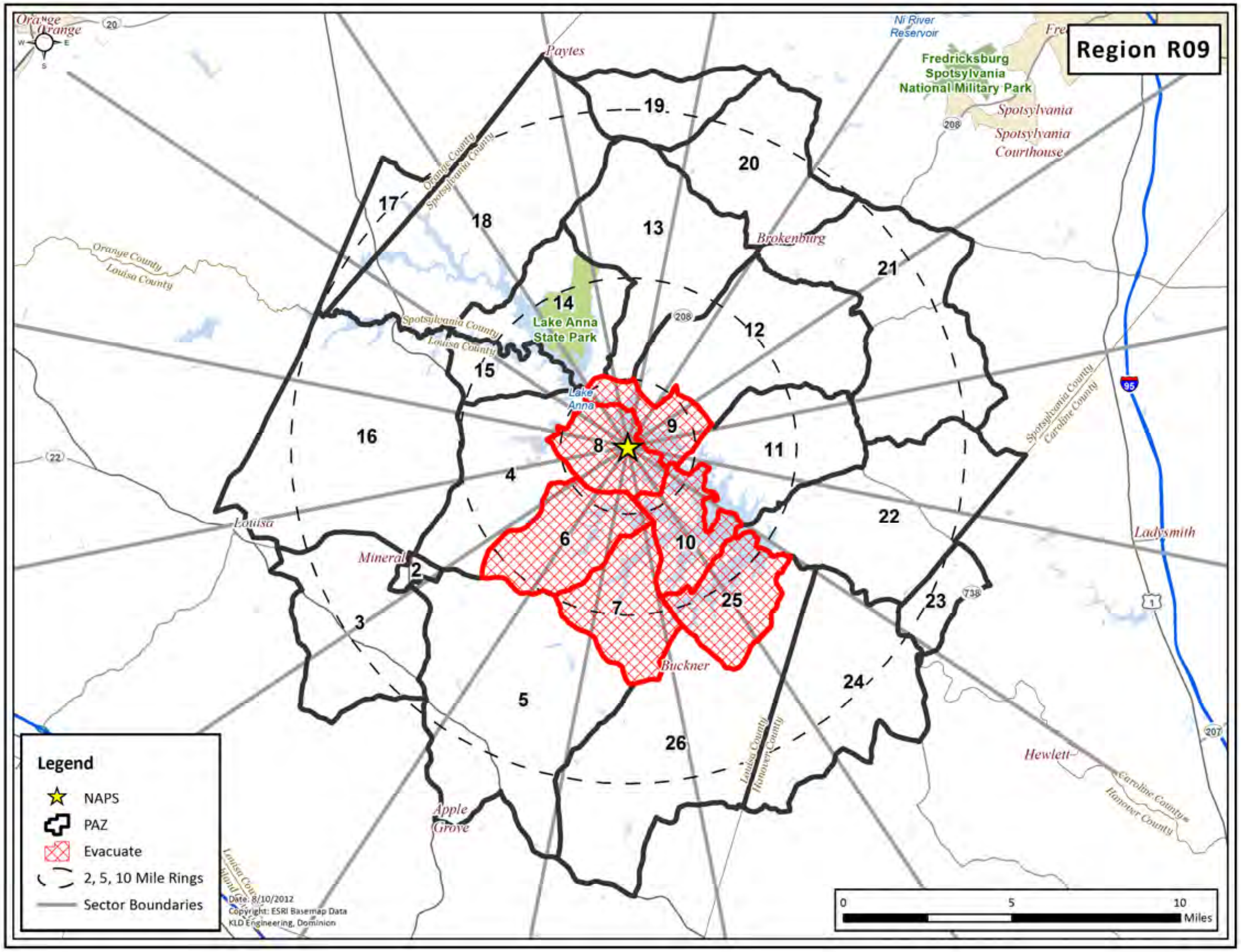


Figure H-9. Region R09

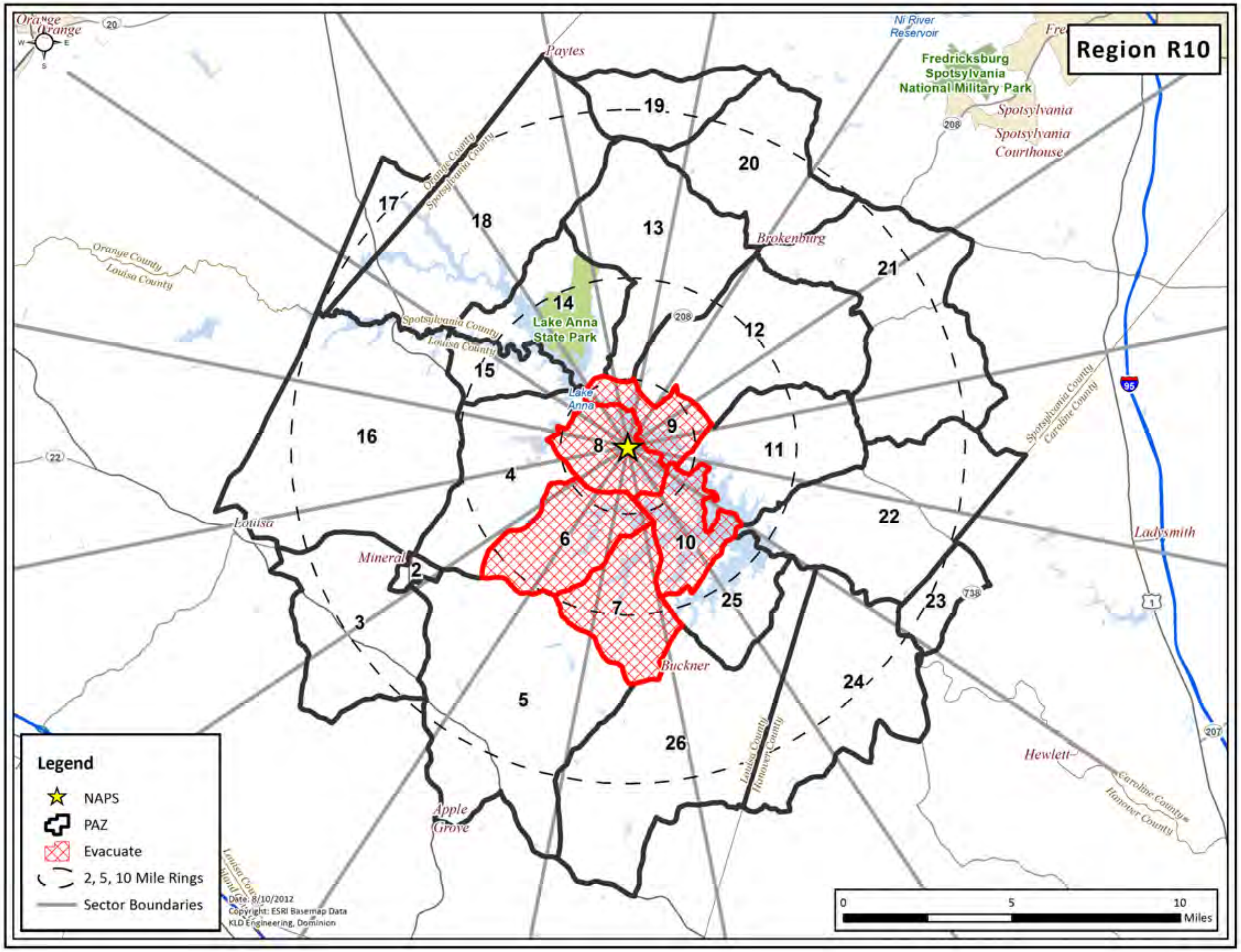


Figure H-10. Region R10

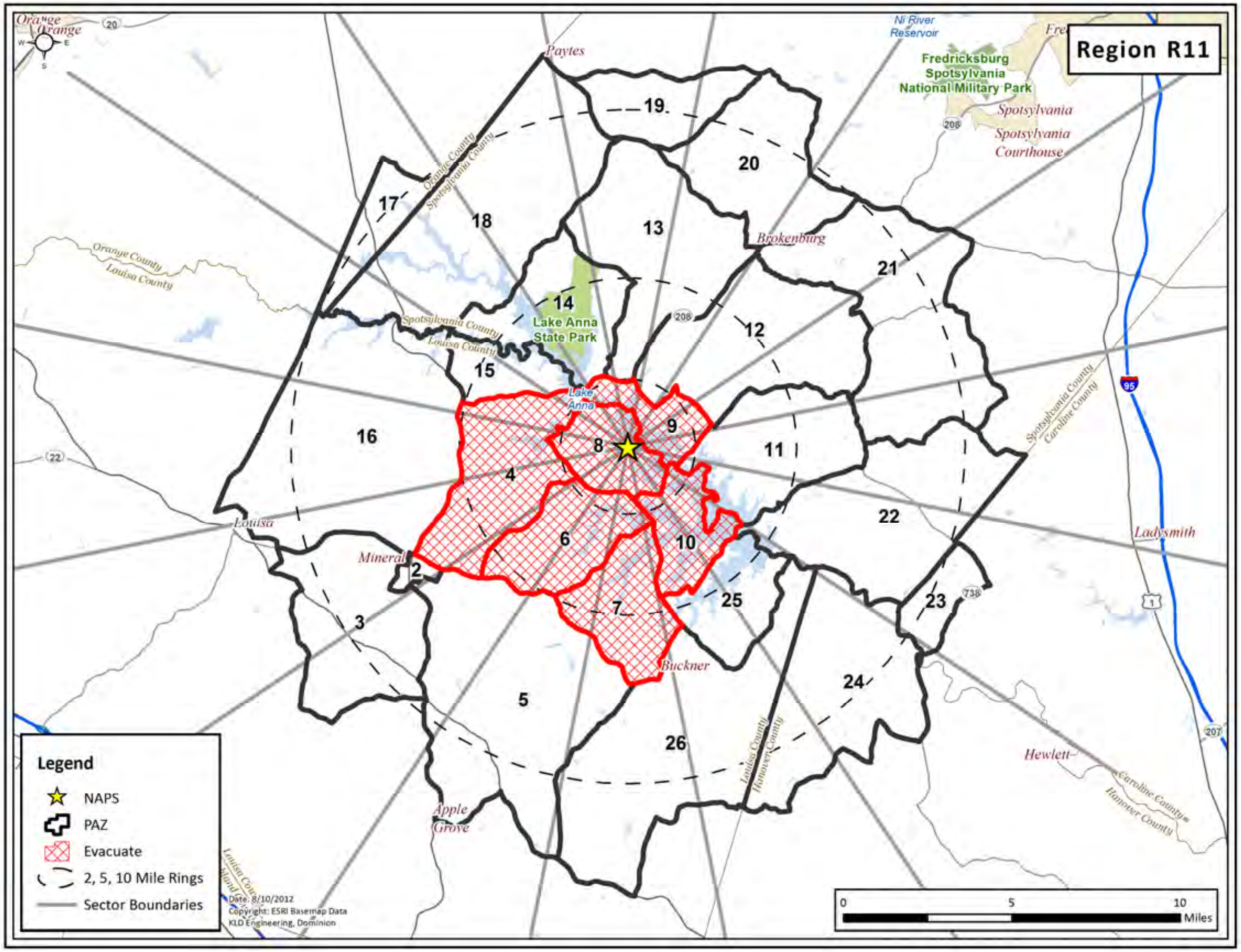


Figure H-11. Region R11

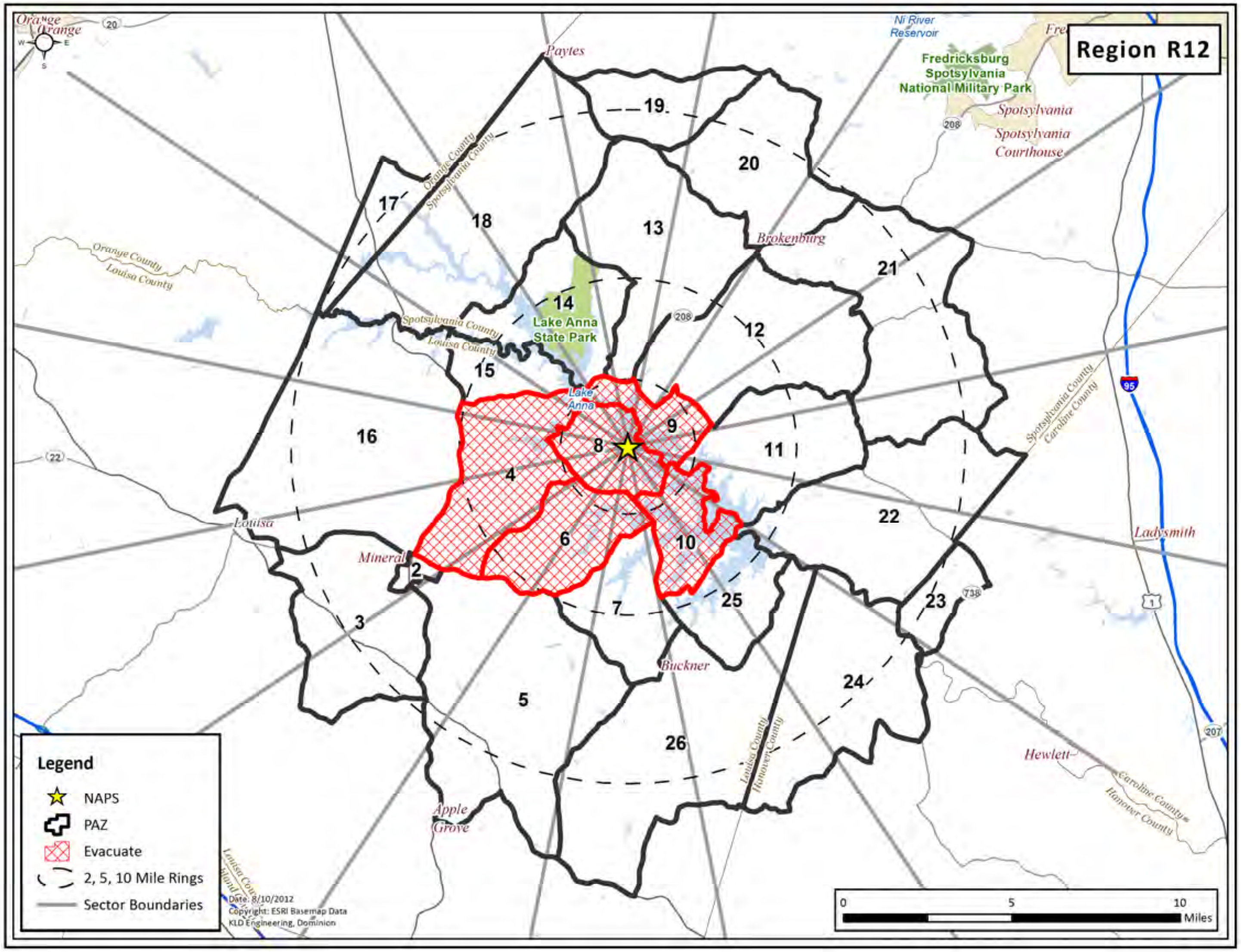


Figure H-12. Region R12

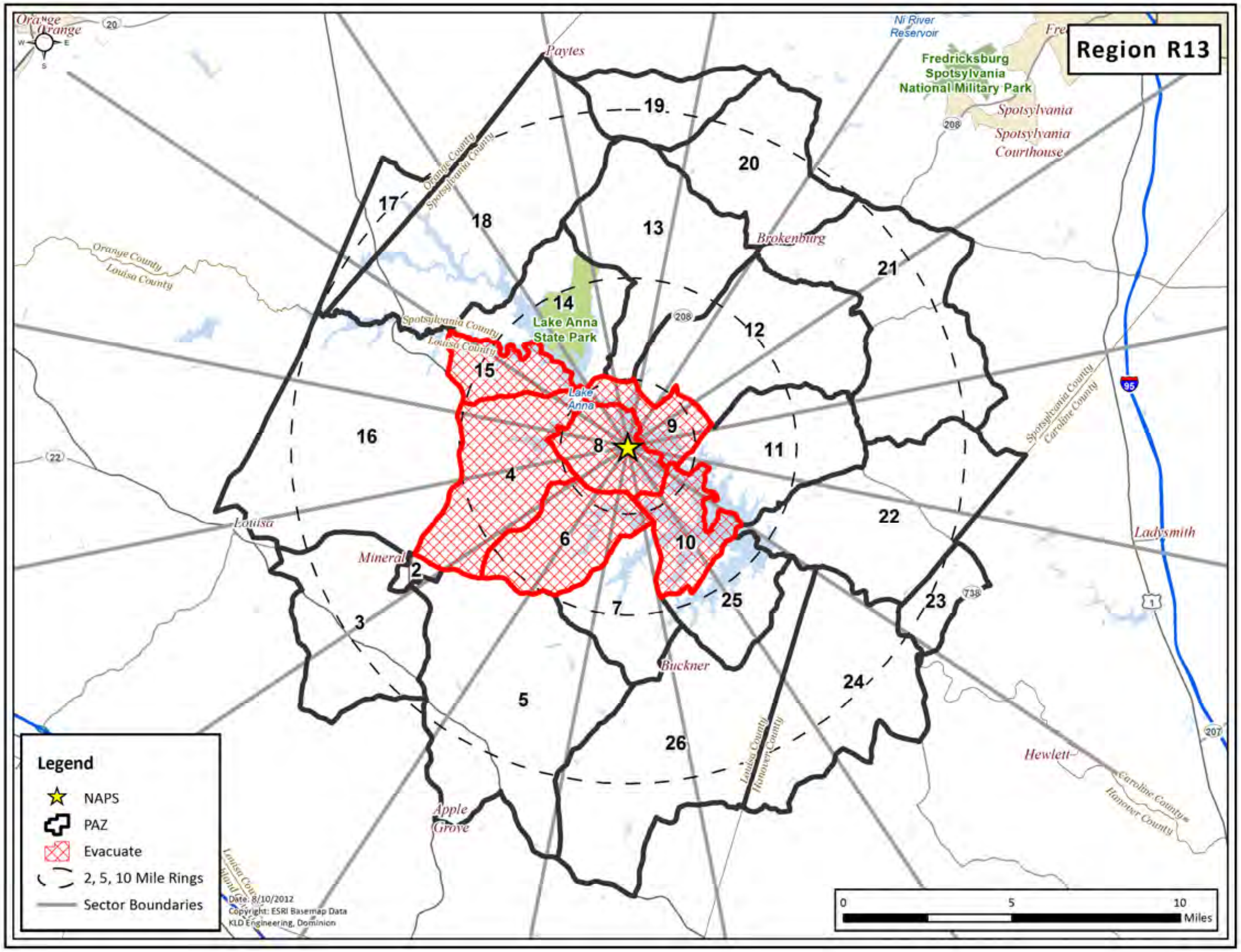


Figure H-13. Region R13

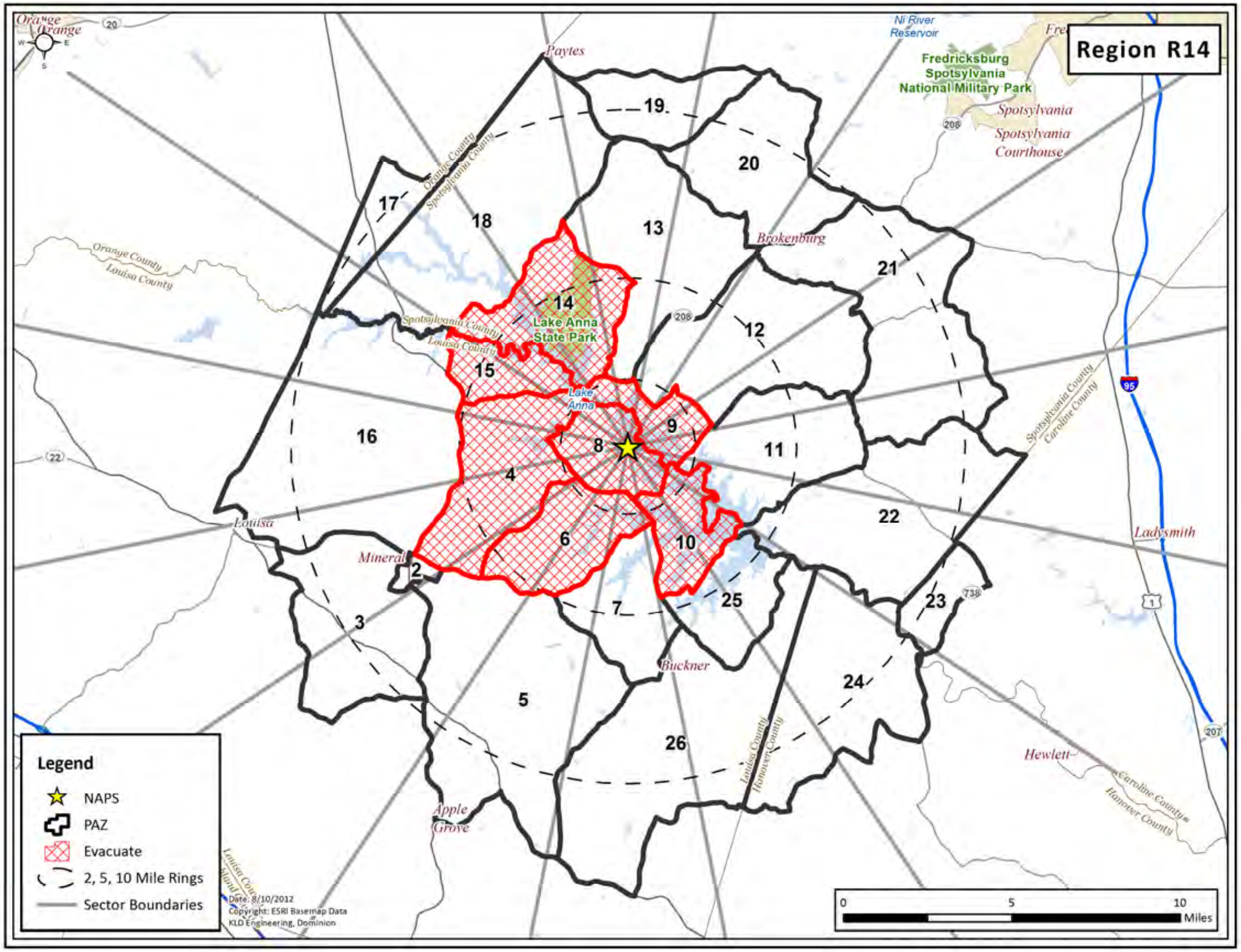


Figure H-14. Region R14

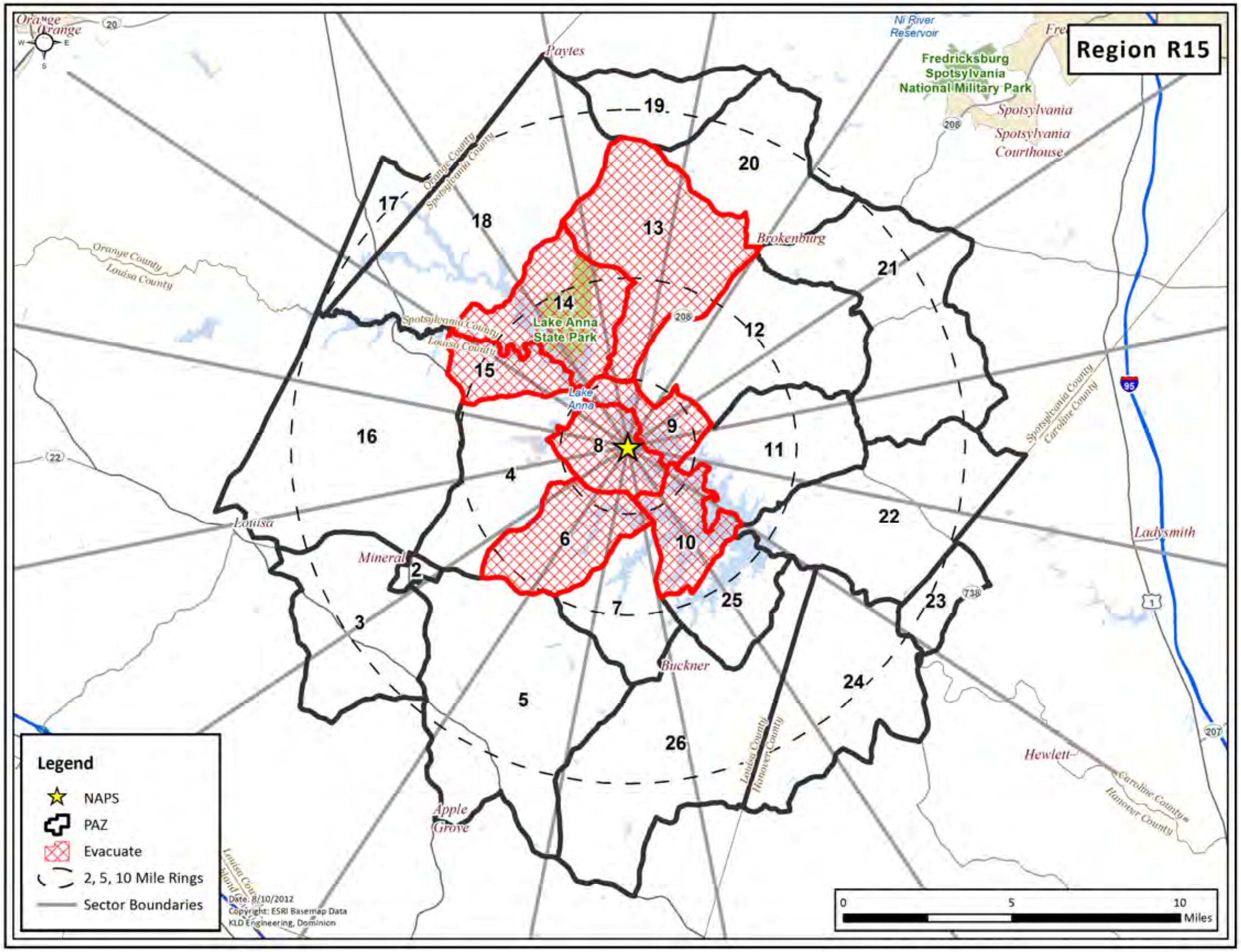


Figure H-15. Region R15

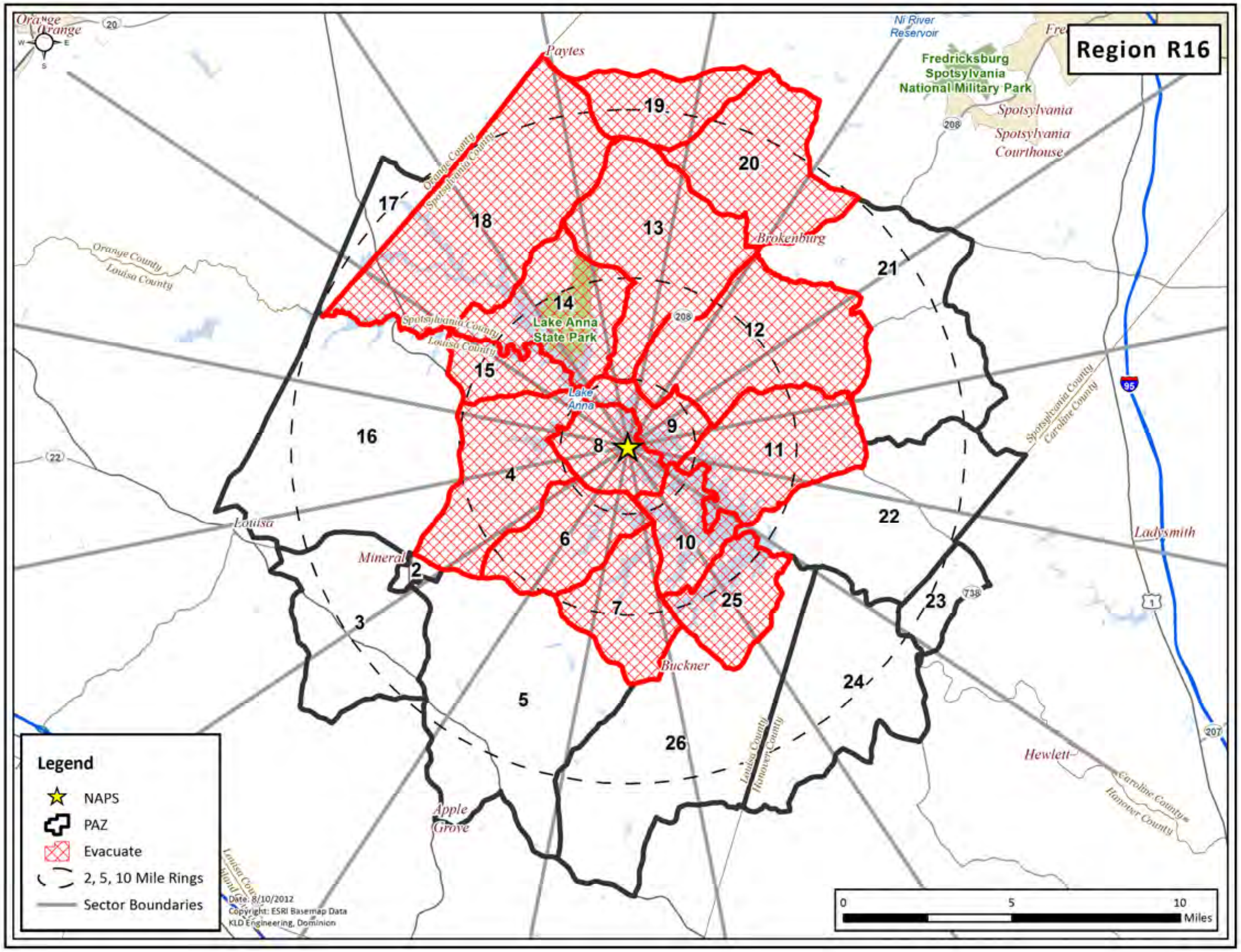


Figure H-16. Region R16

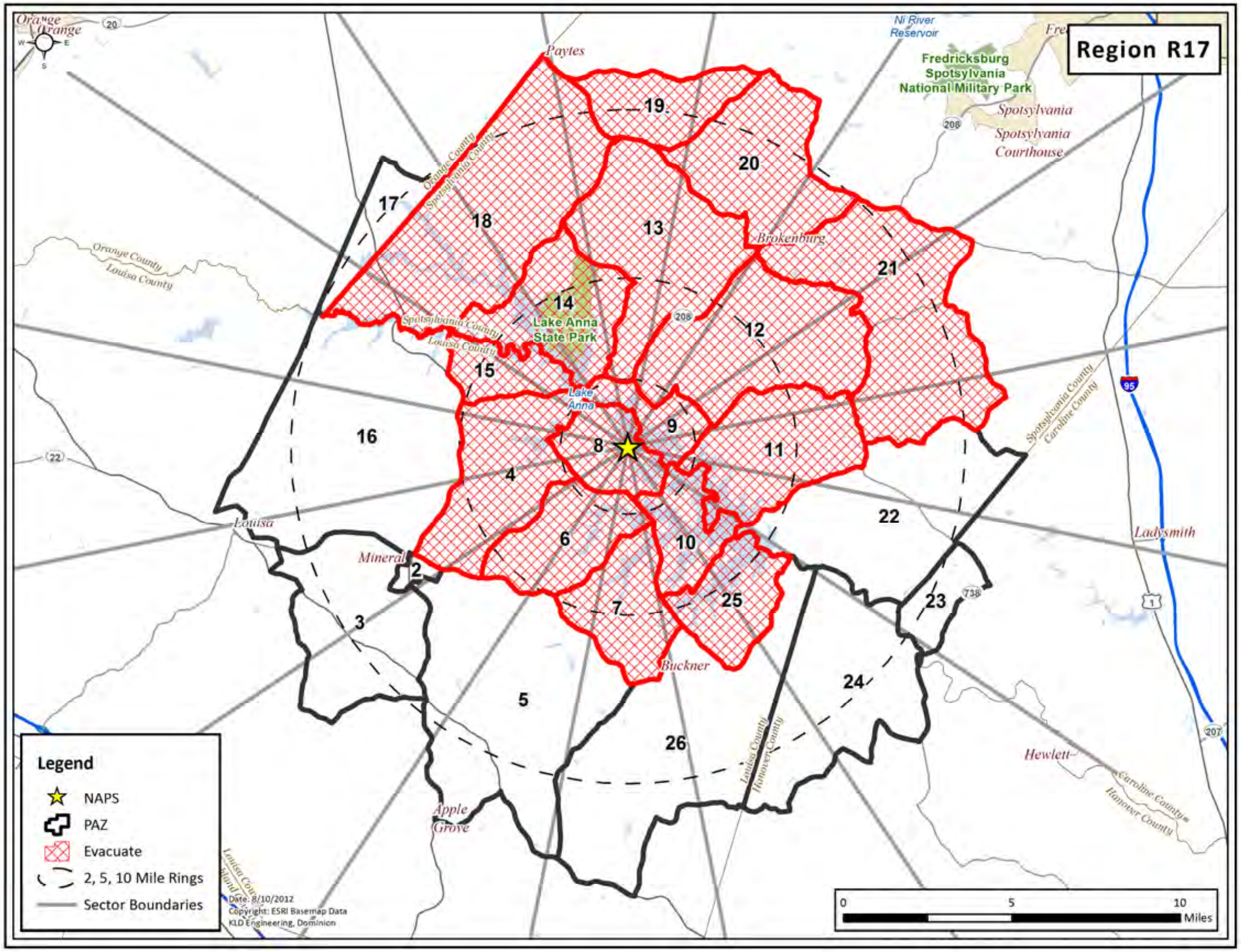


Figure H-17. Region R17

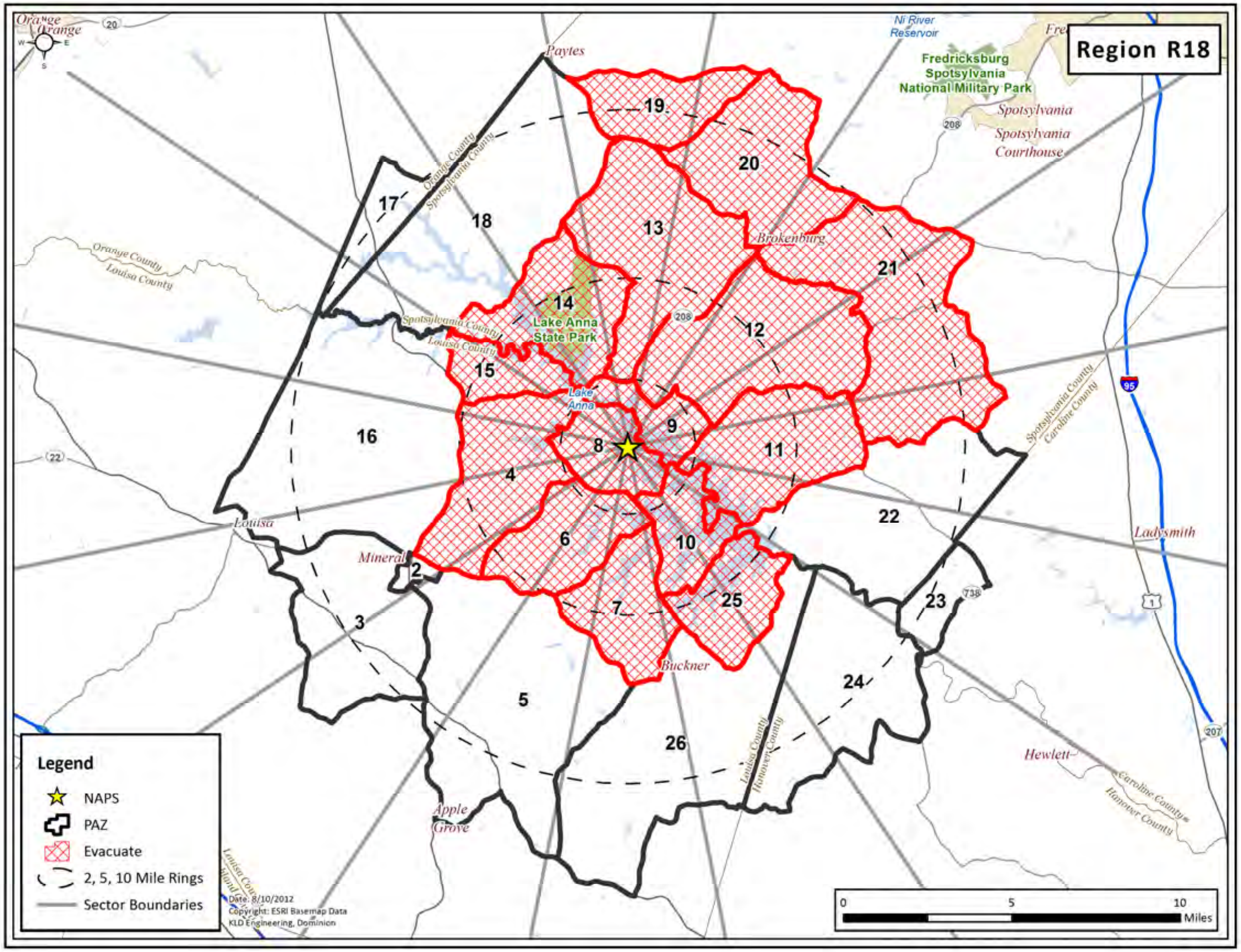


Figure H-18. Region R18

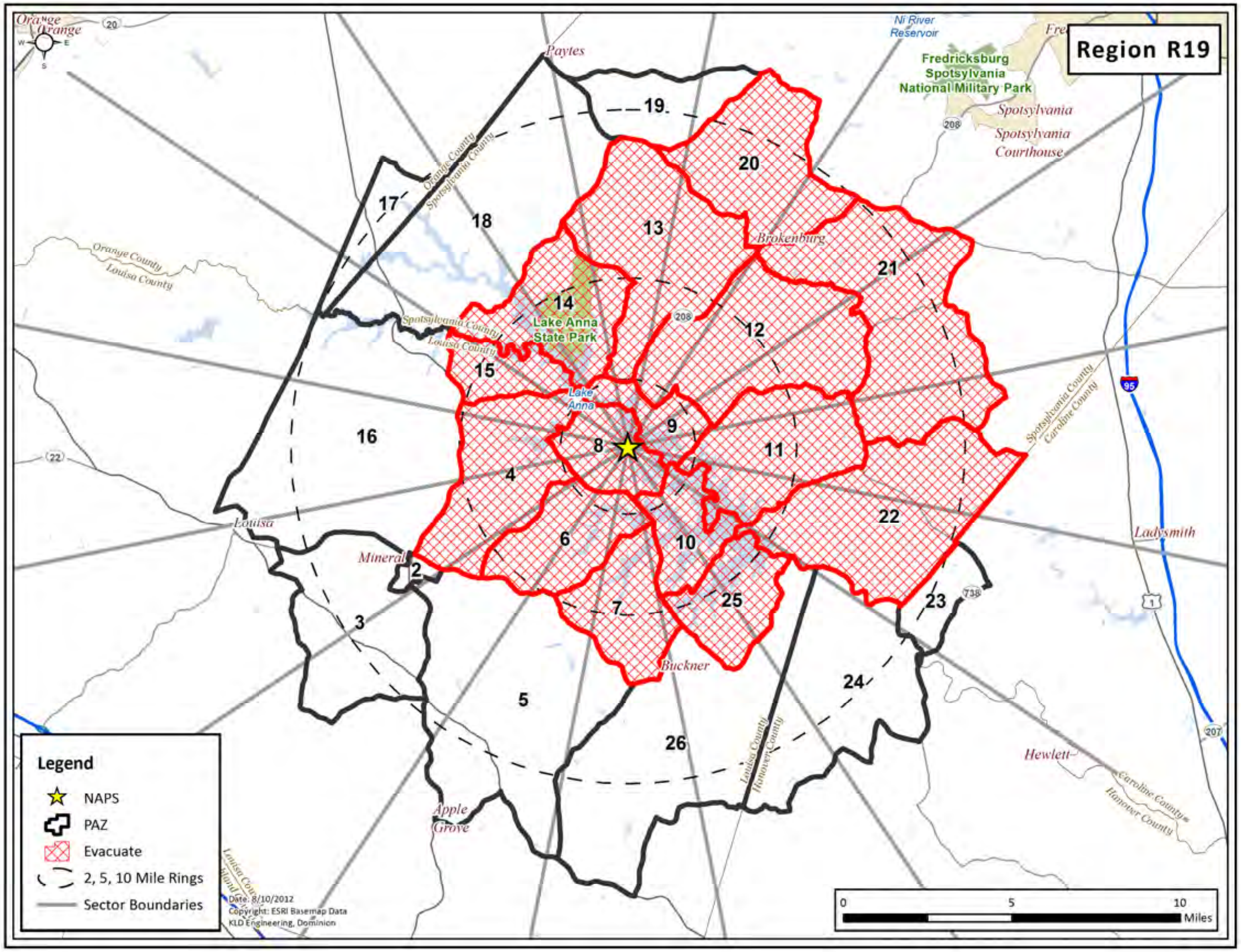


Figure H-19. Region R19

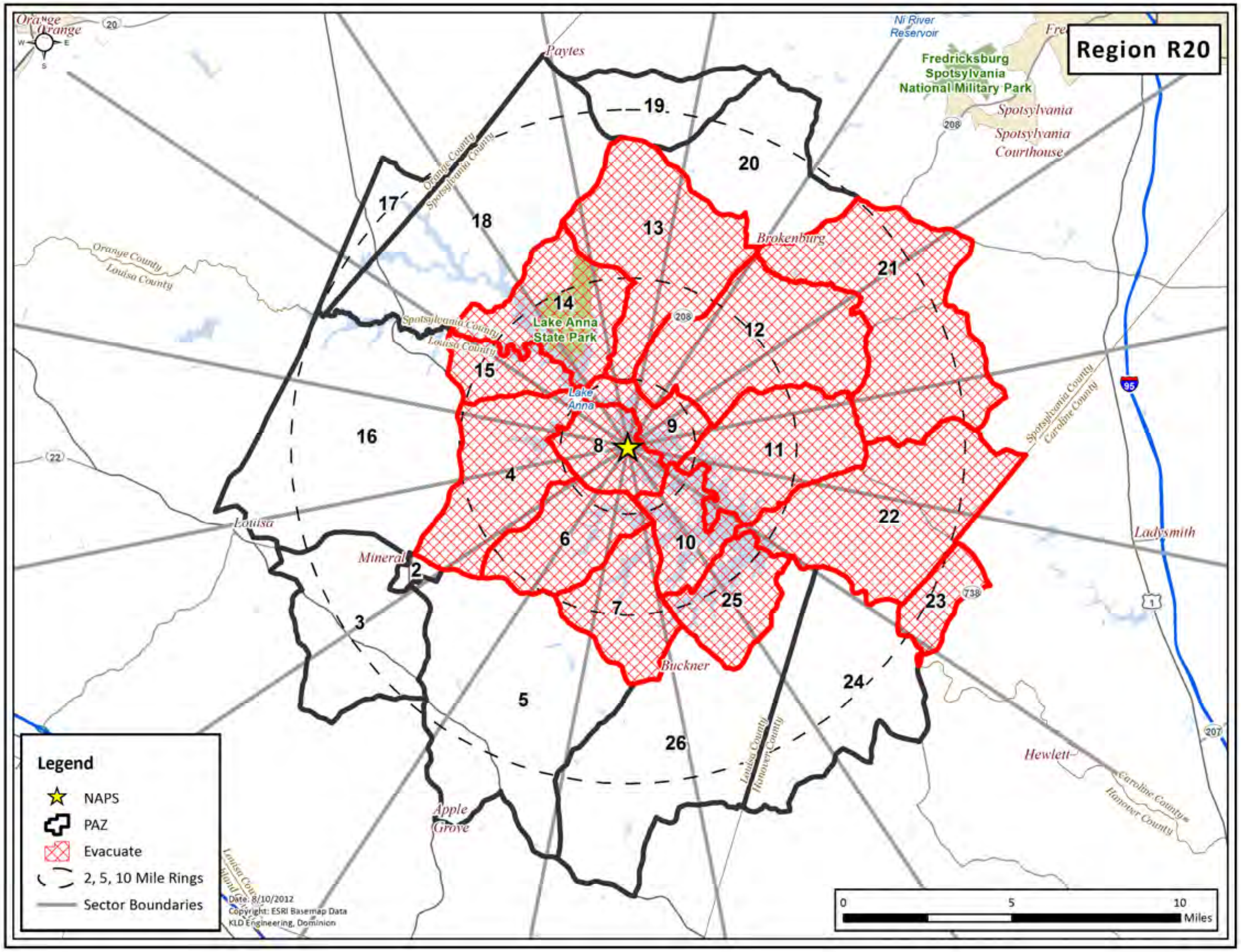


Figure H-20. Region R20

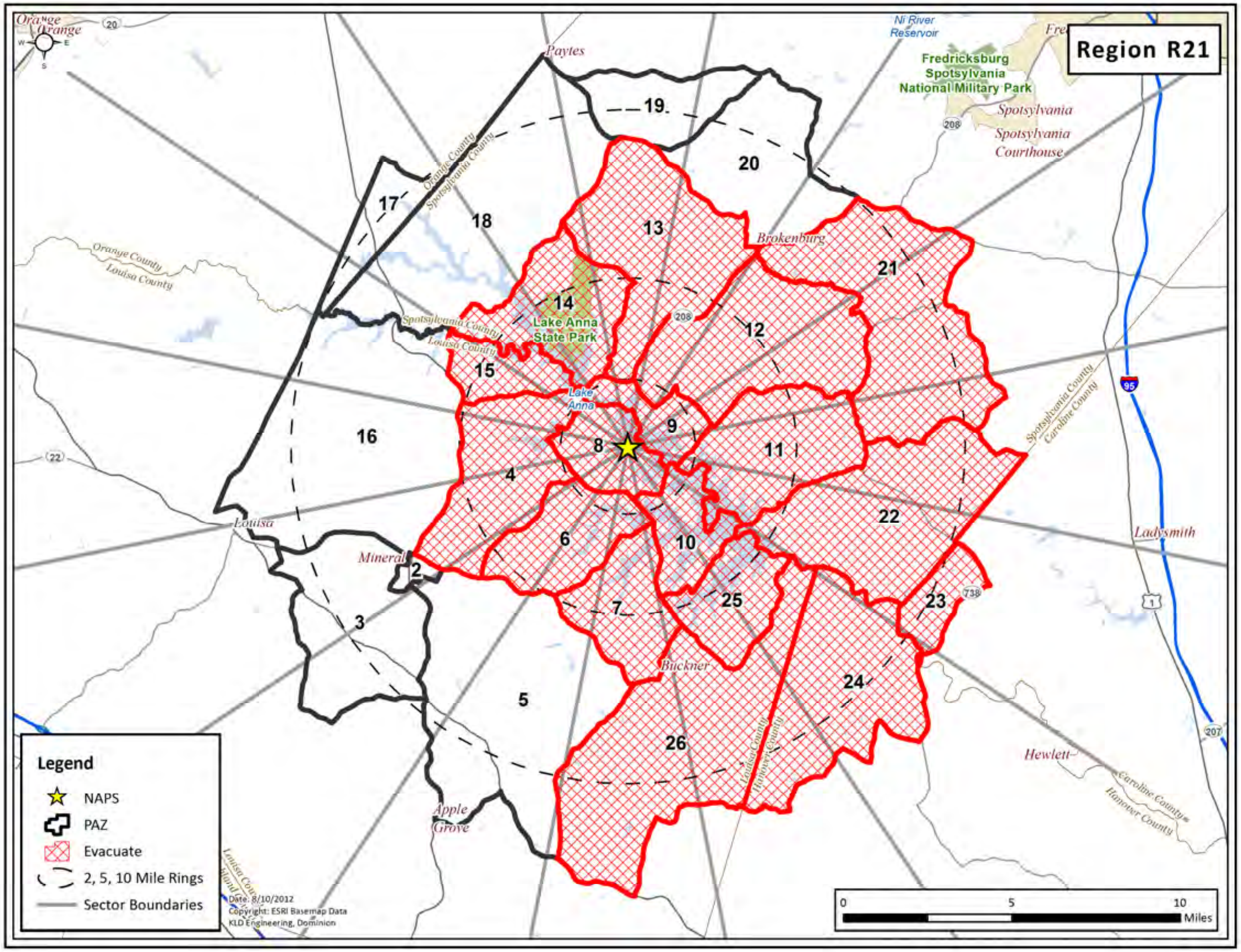


Figure H-21. Region R21

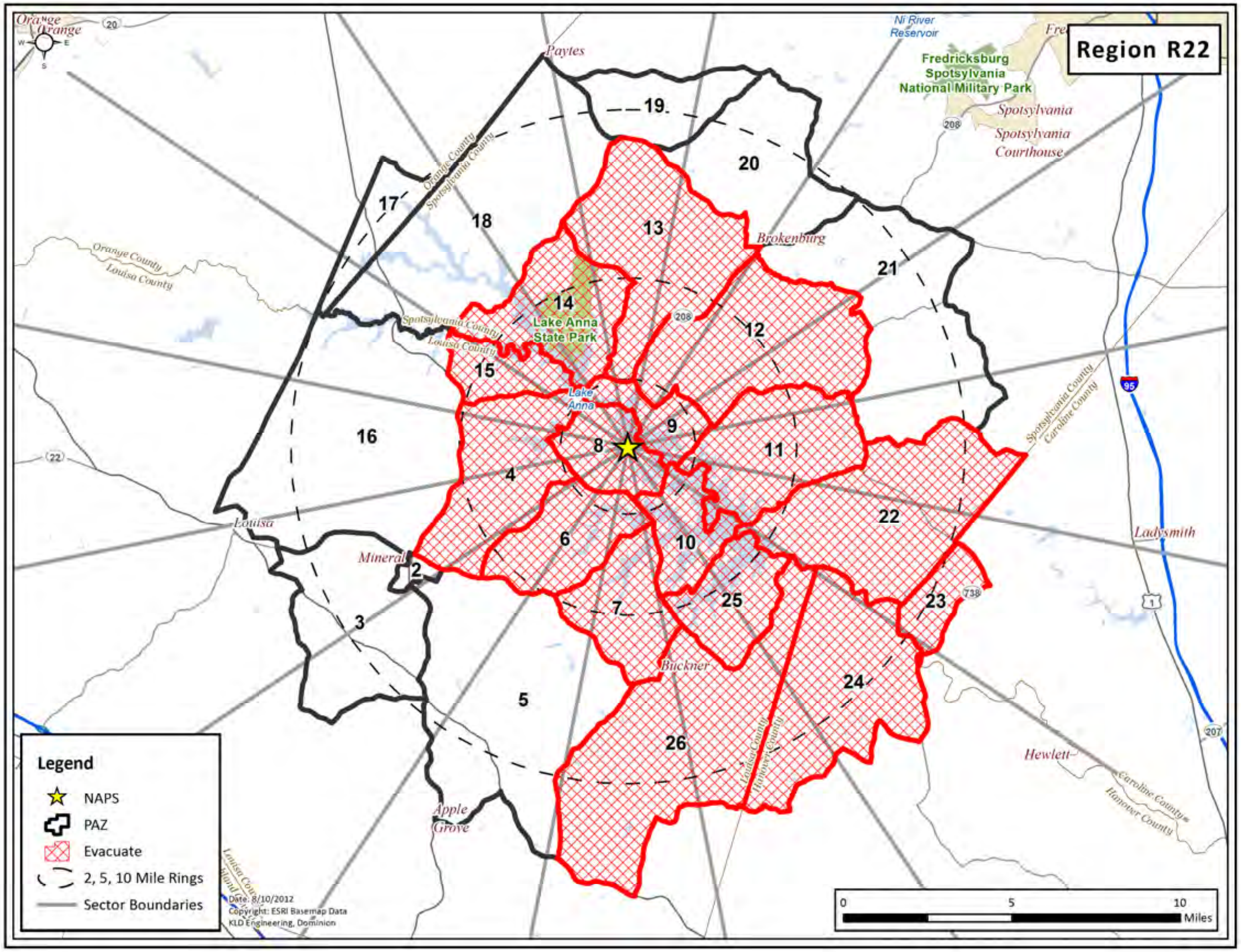


Figure H-22. Region R22

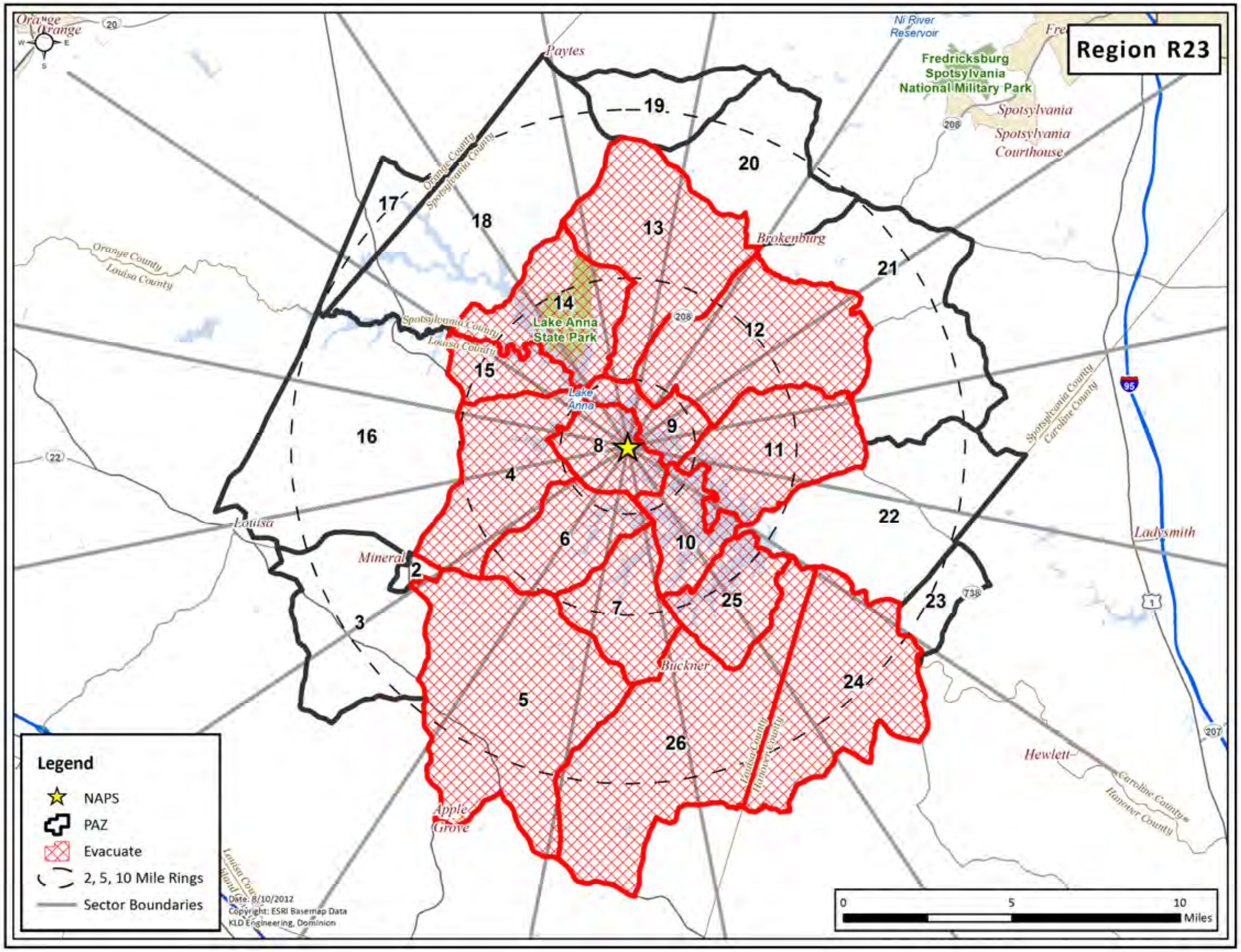


Figure H-23. Region R23

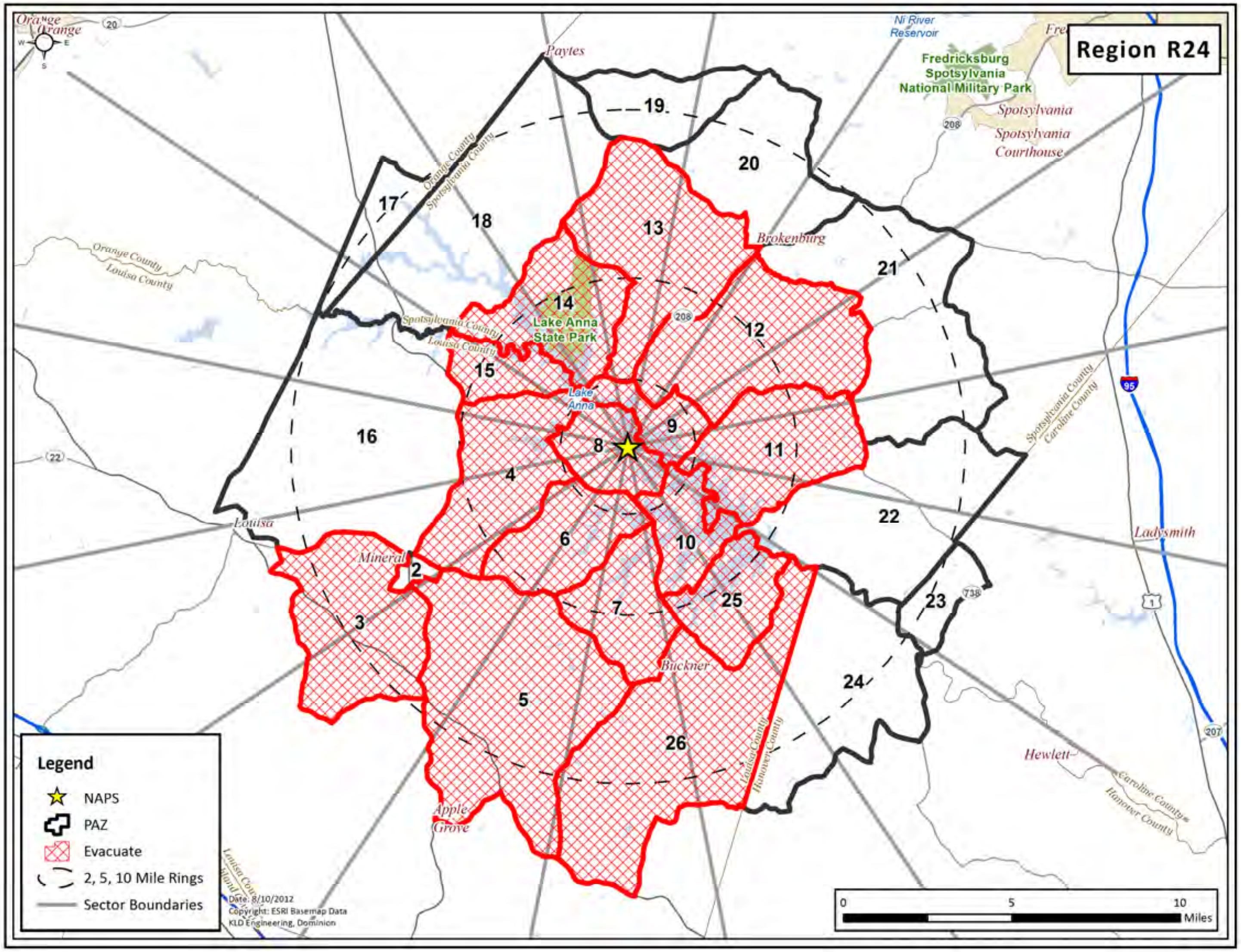


Figure H-24. Region R24

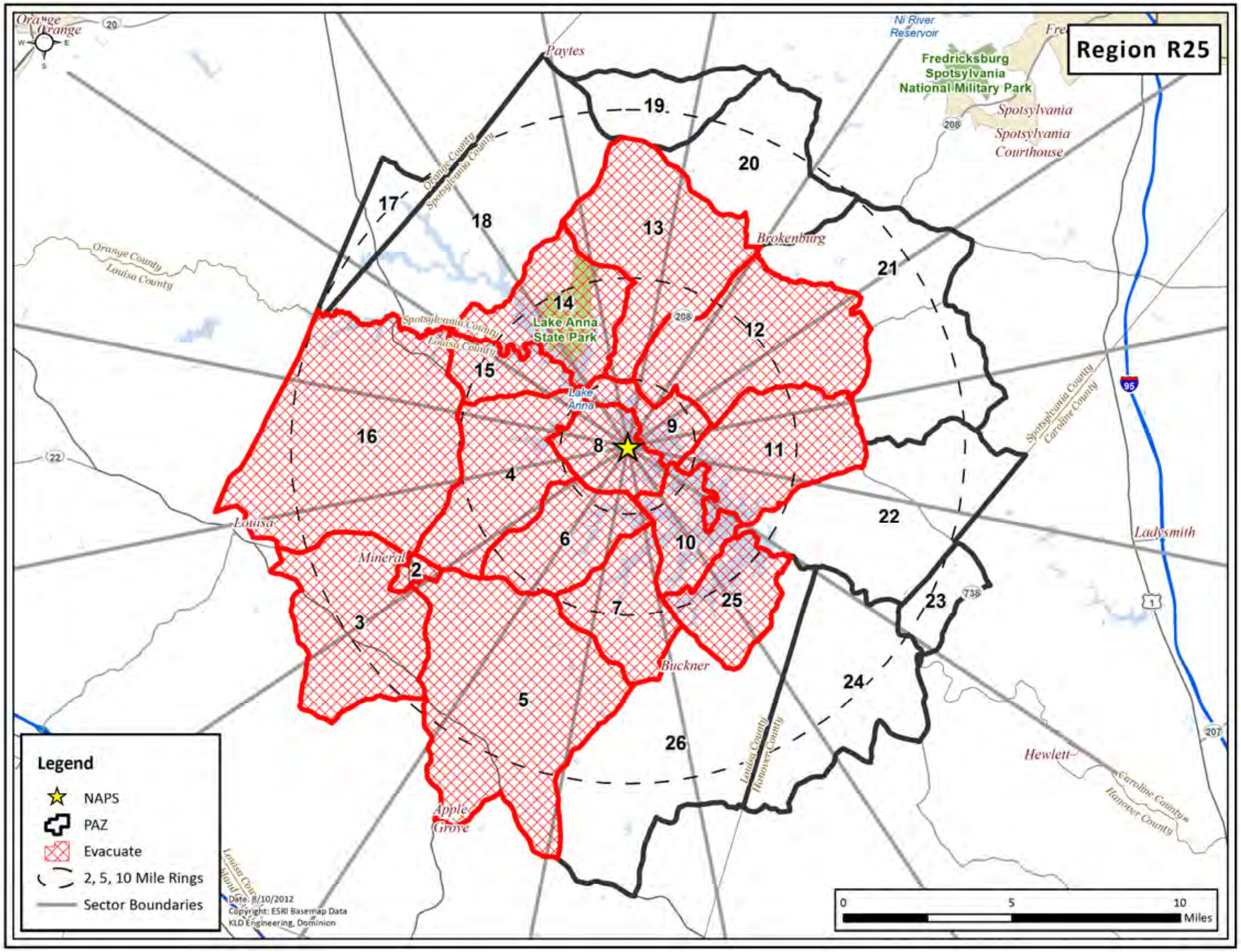


Figure H-25. Region R25

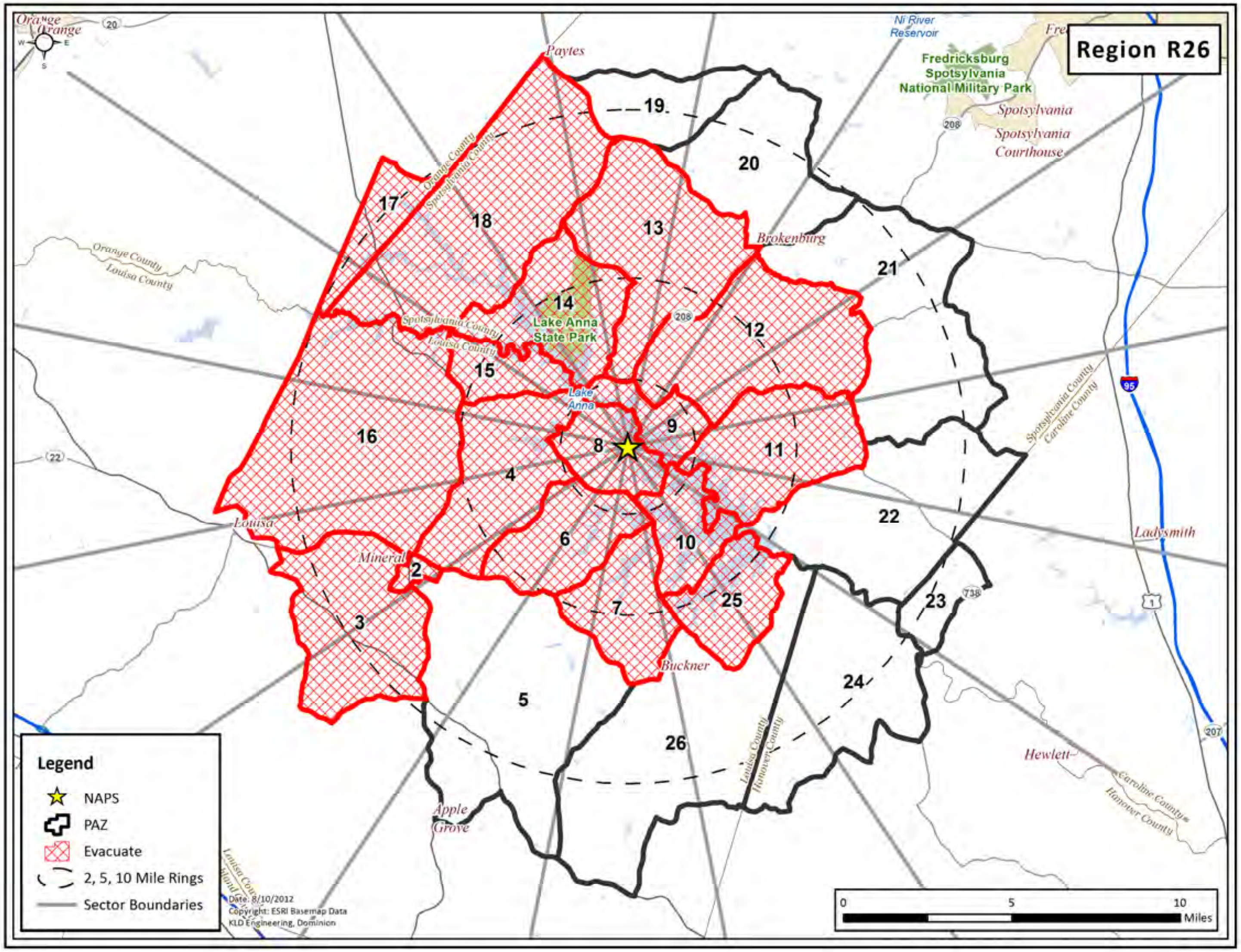


Figure H-26. Region R26

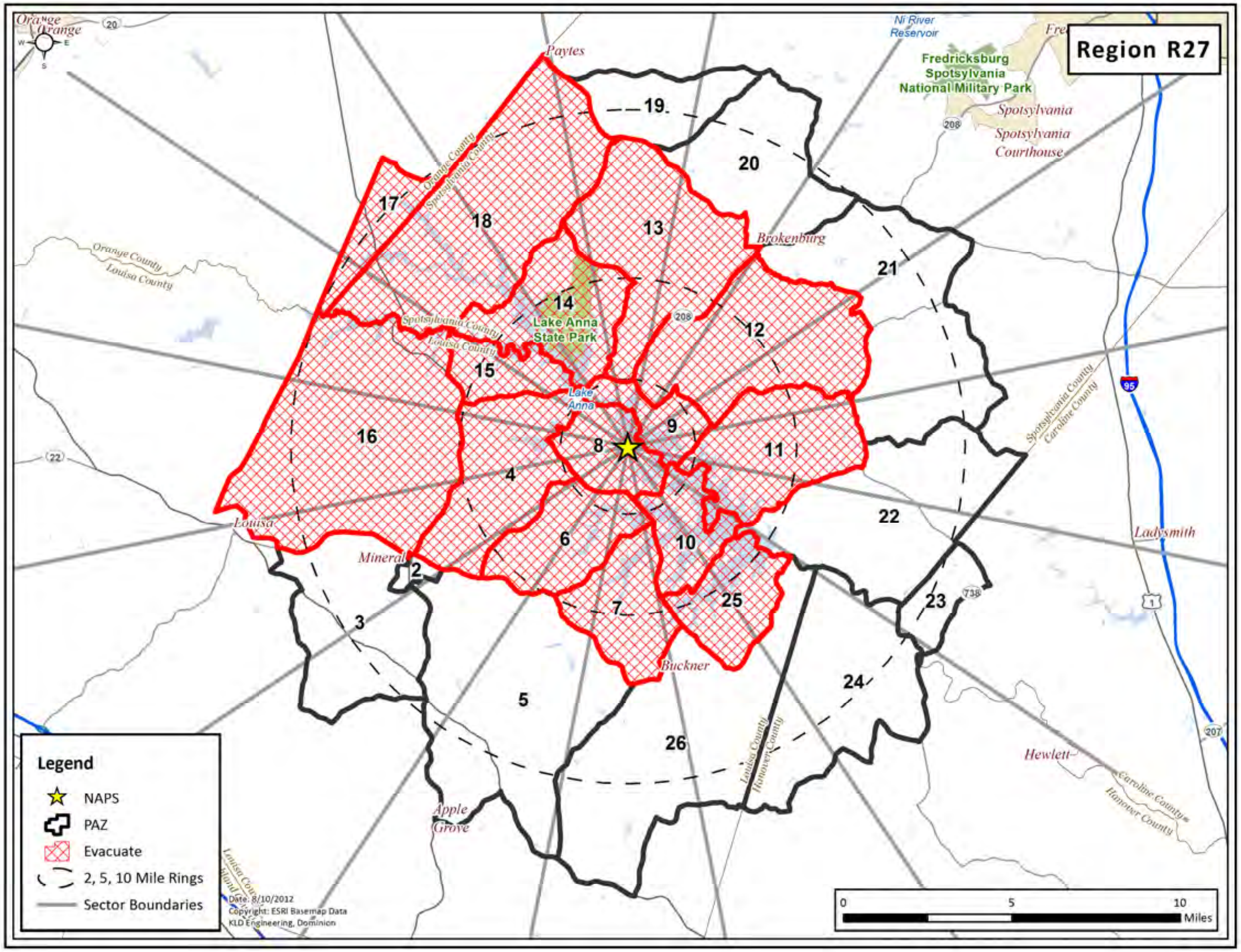


Figure H-27. Region R27

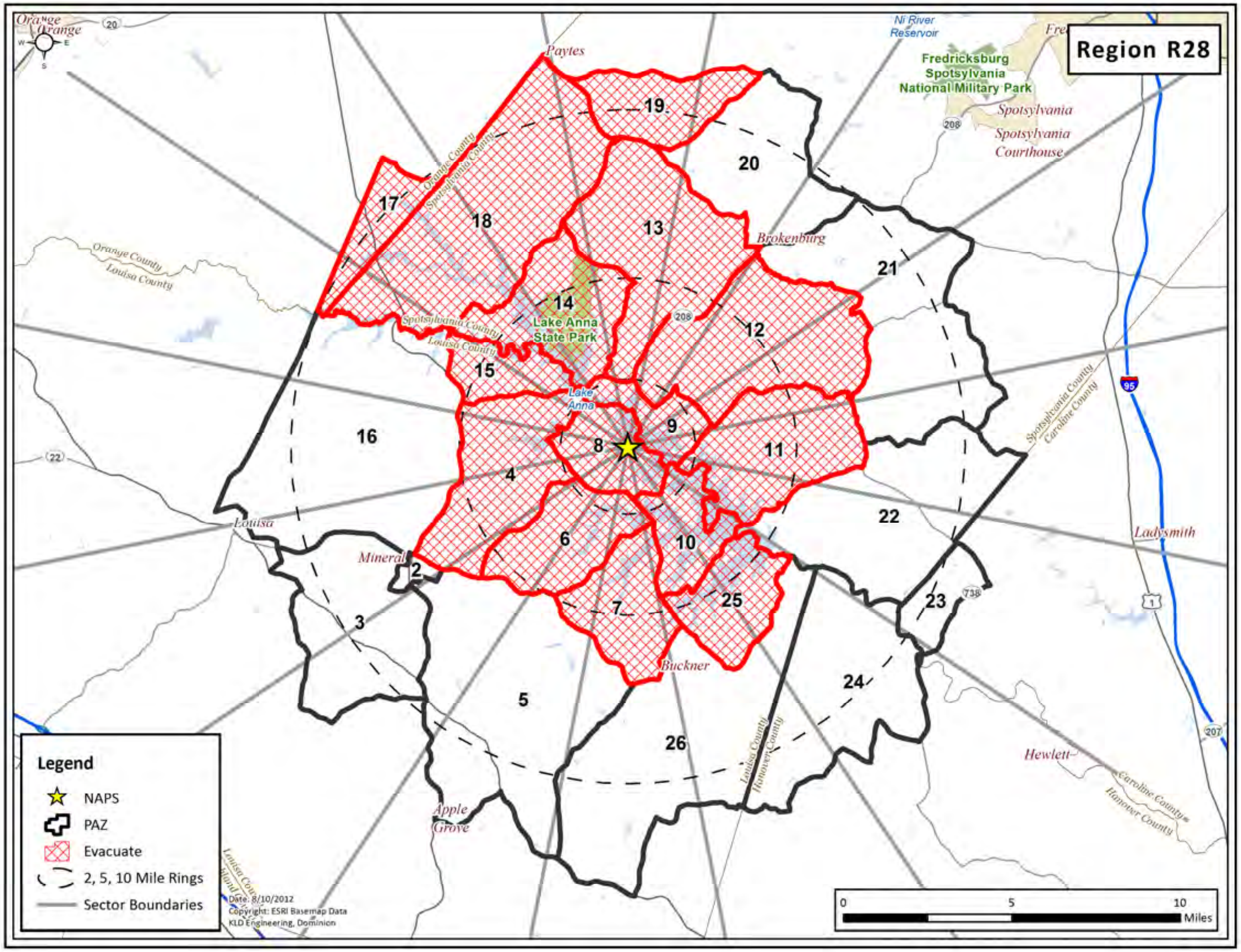


Figure H-28. Region R28

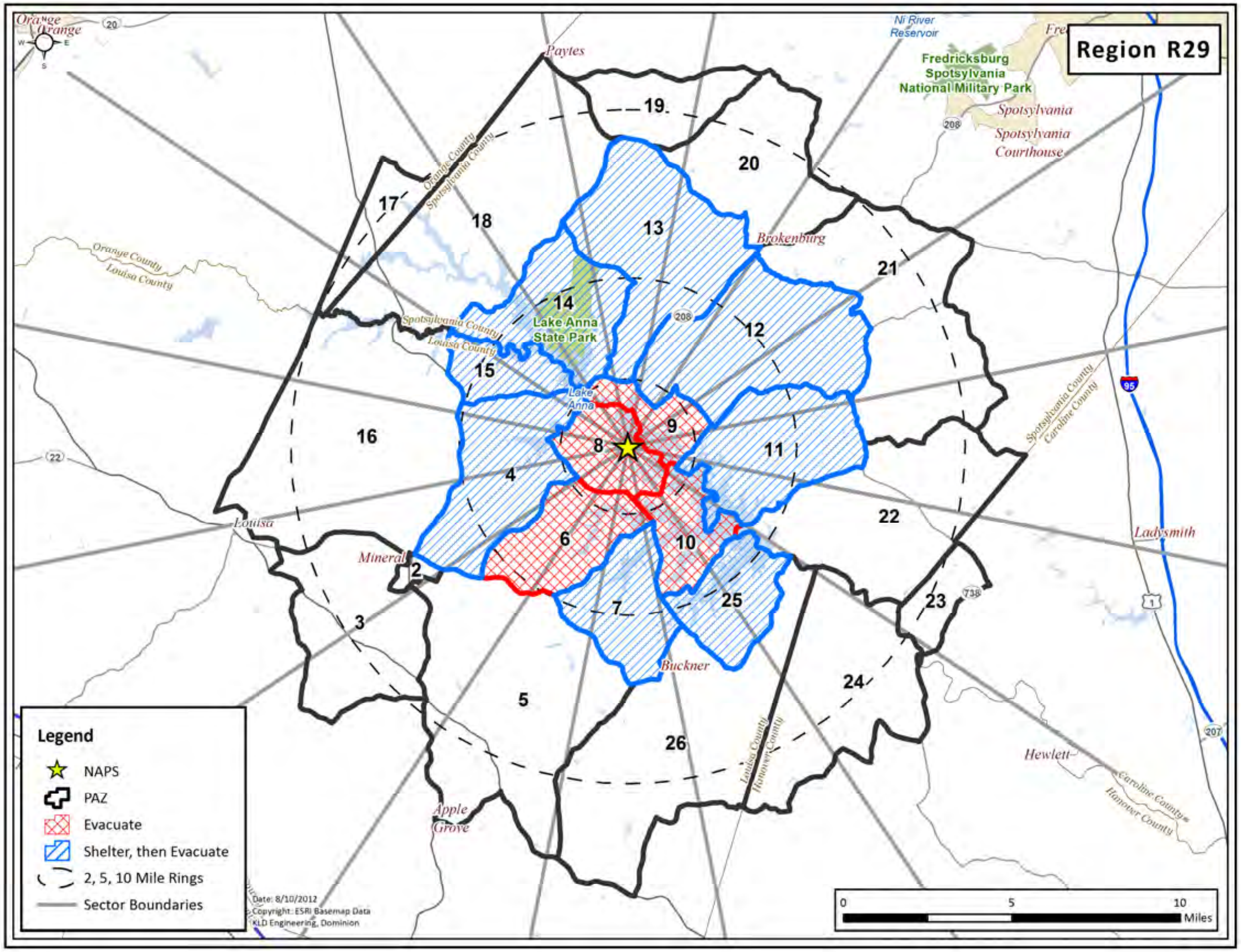


Figure H-29. Region R29

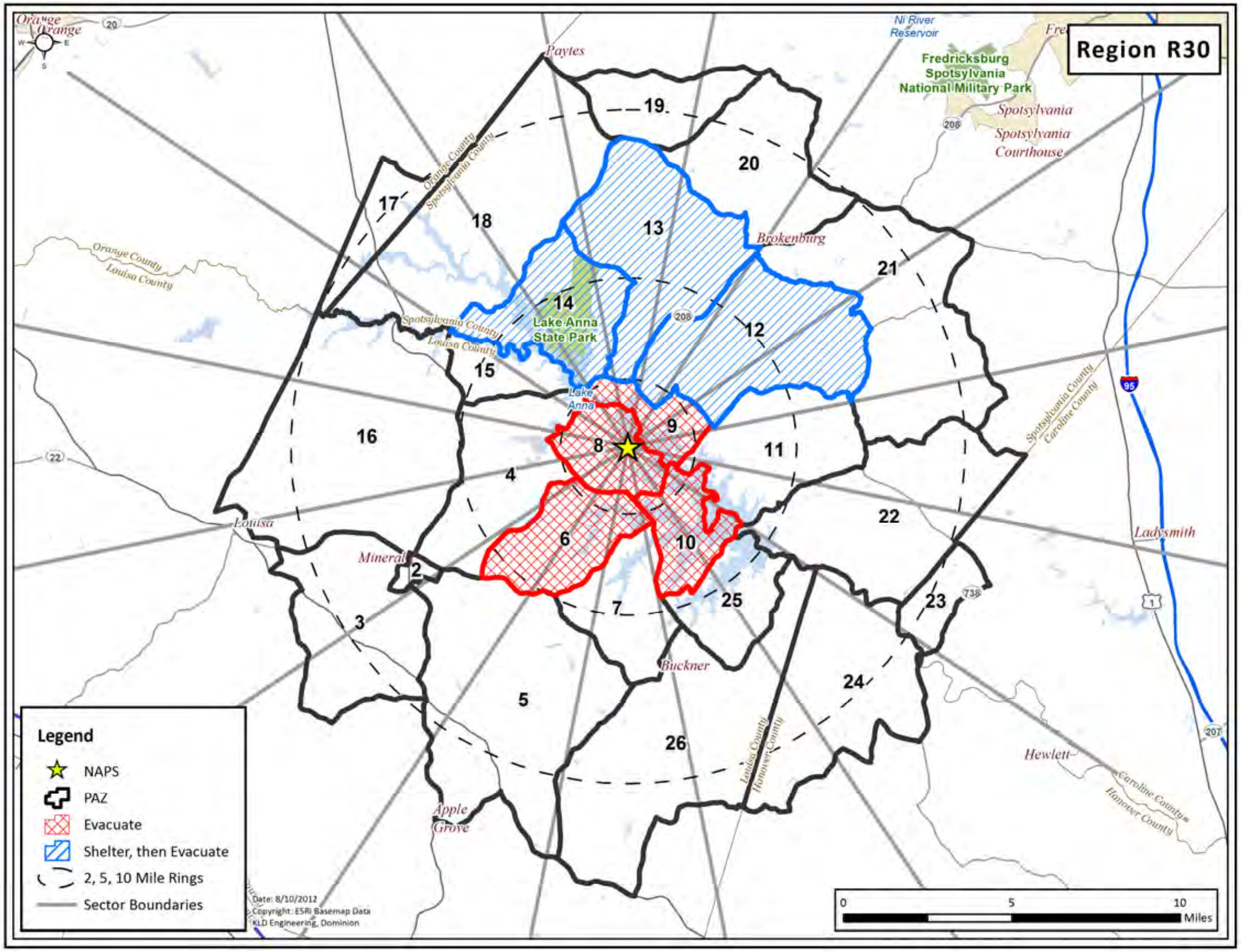


Figure H-30. Region R30

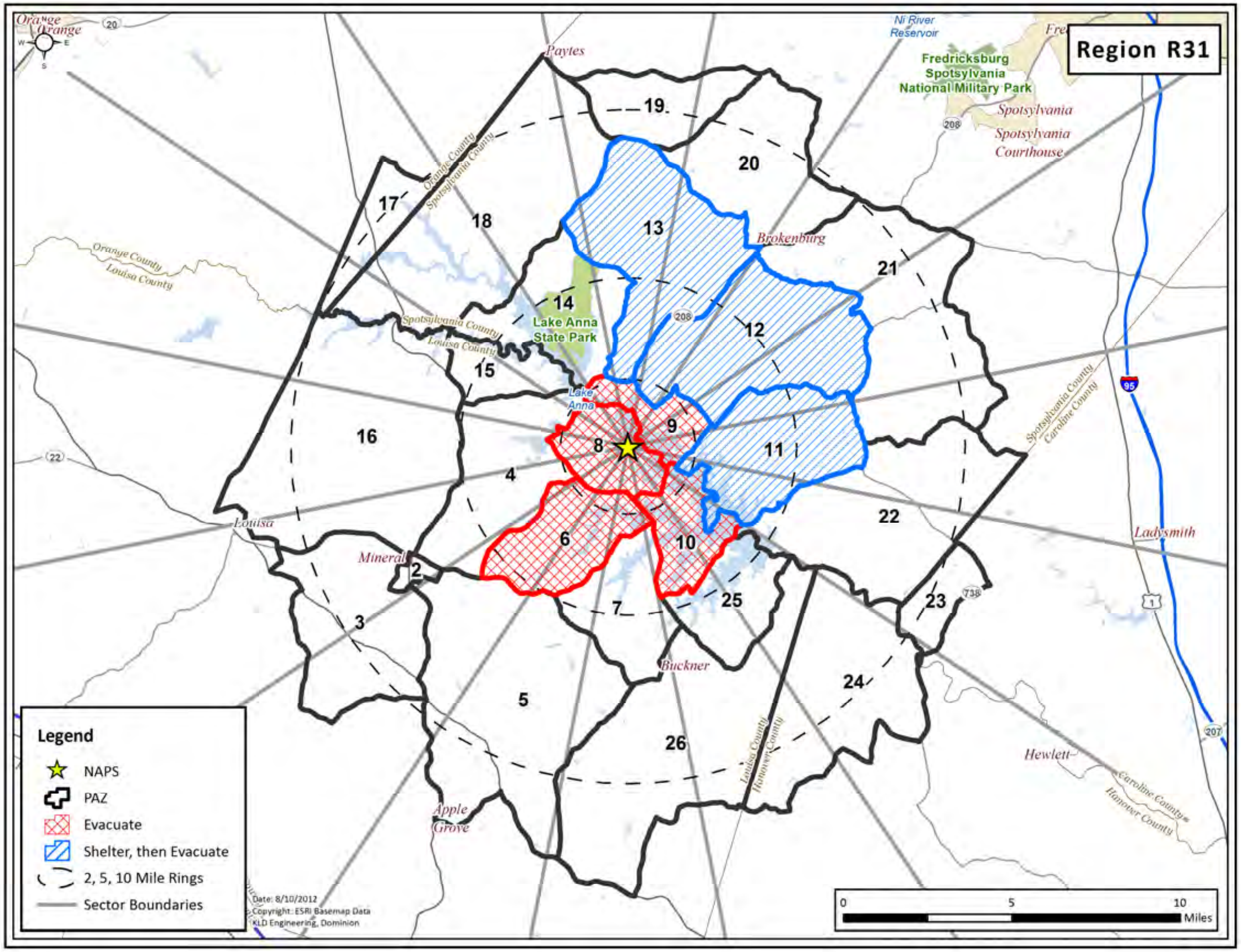


Figure H-31. Region R31

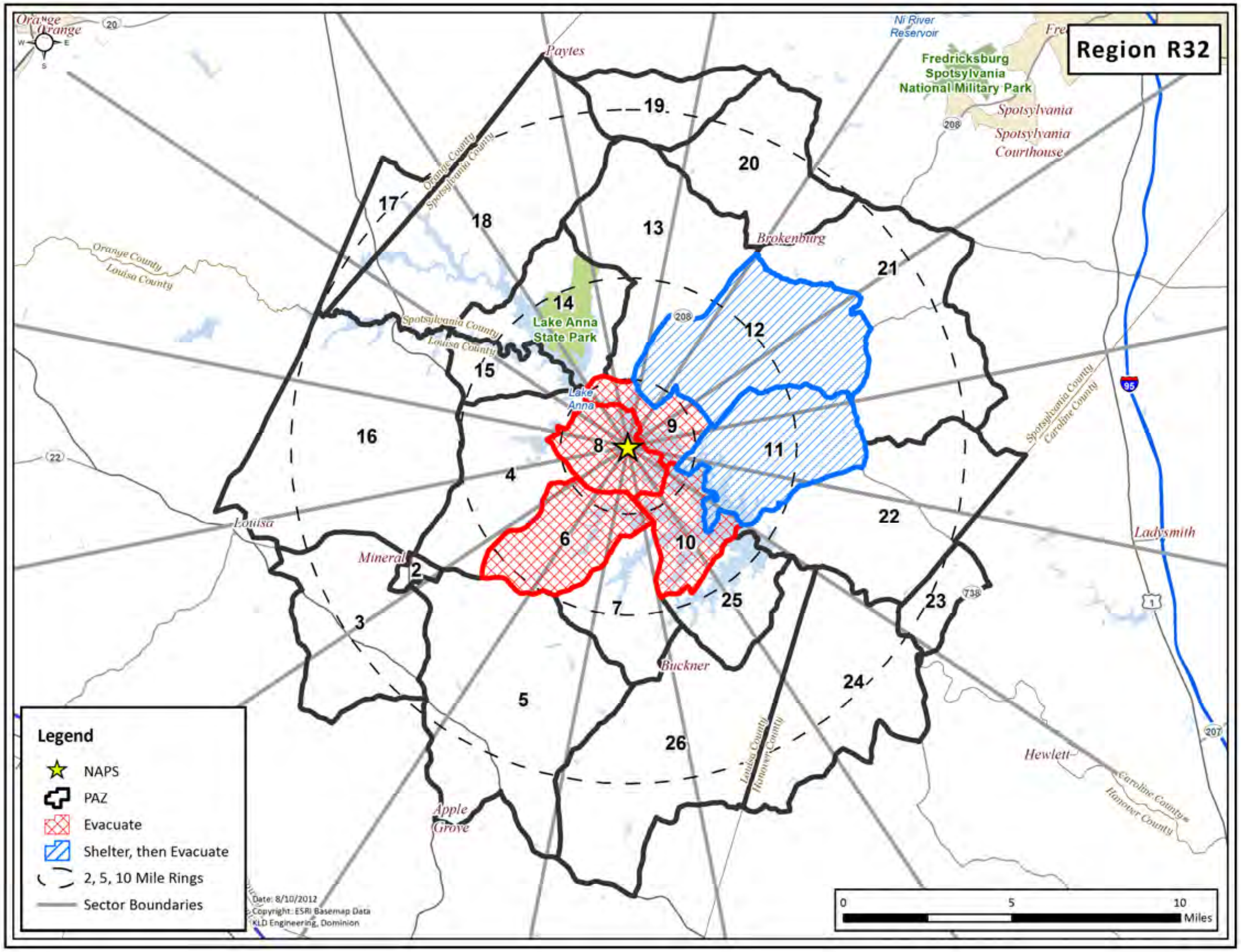


Figure H-32. Region R32

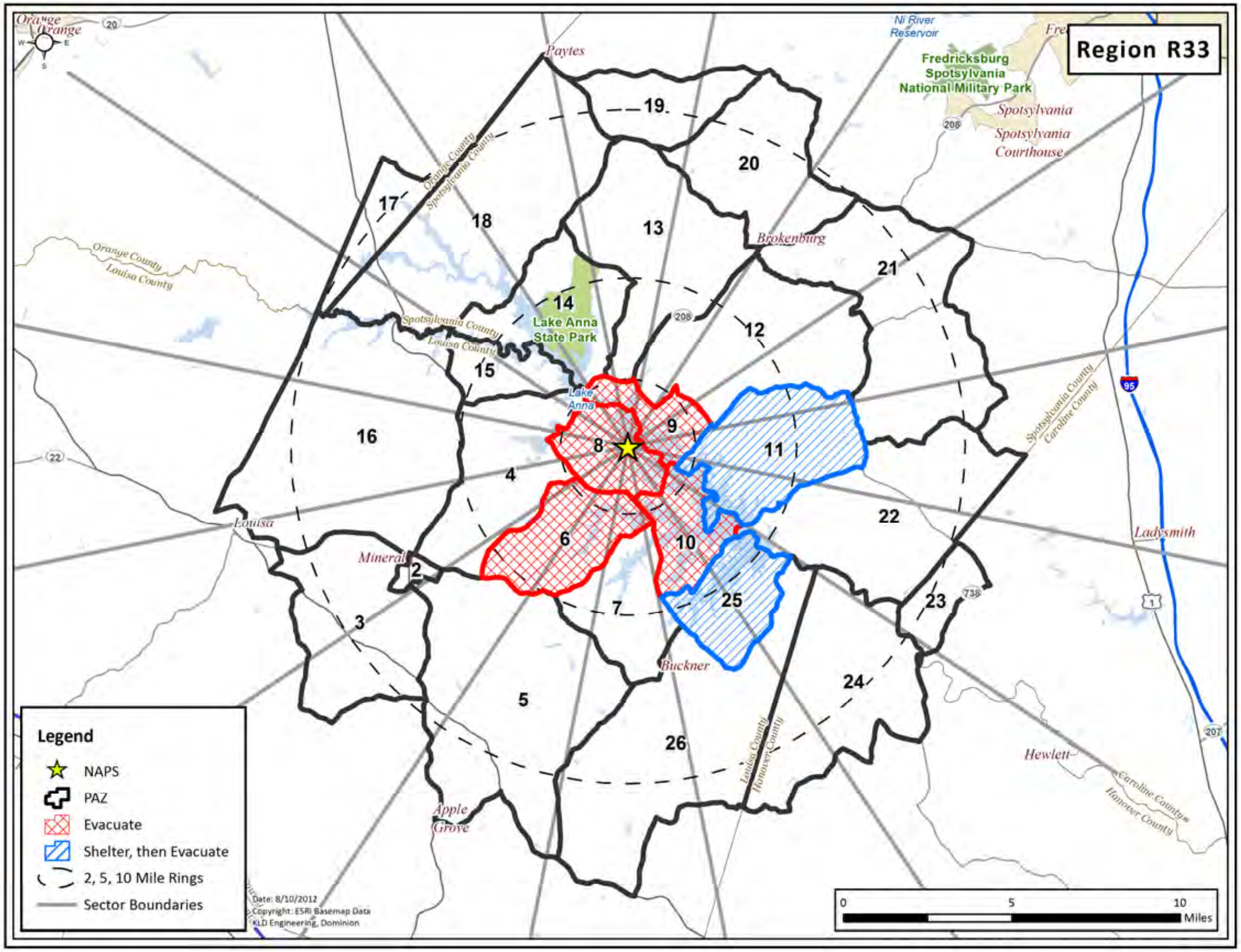


Figure H-33. Region R33

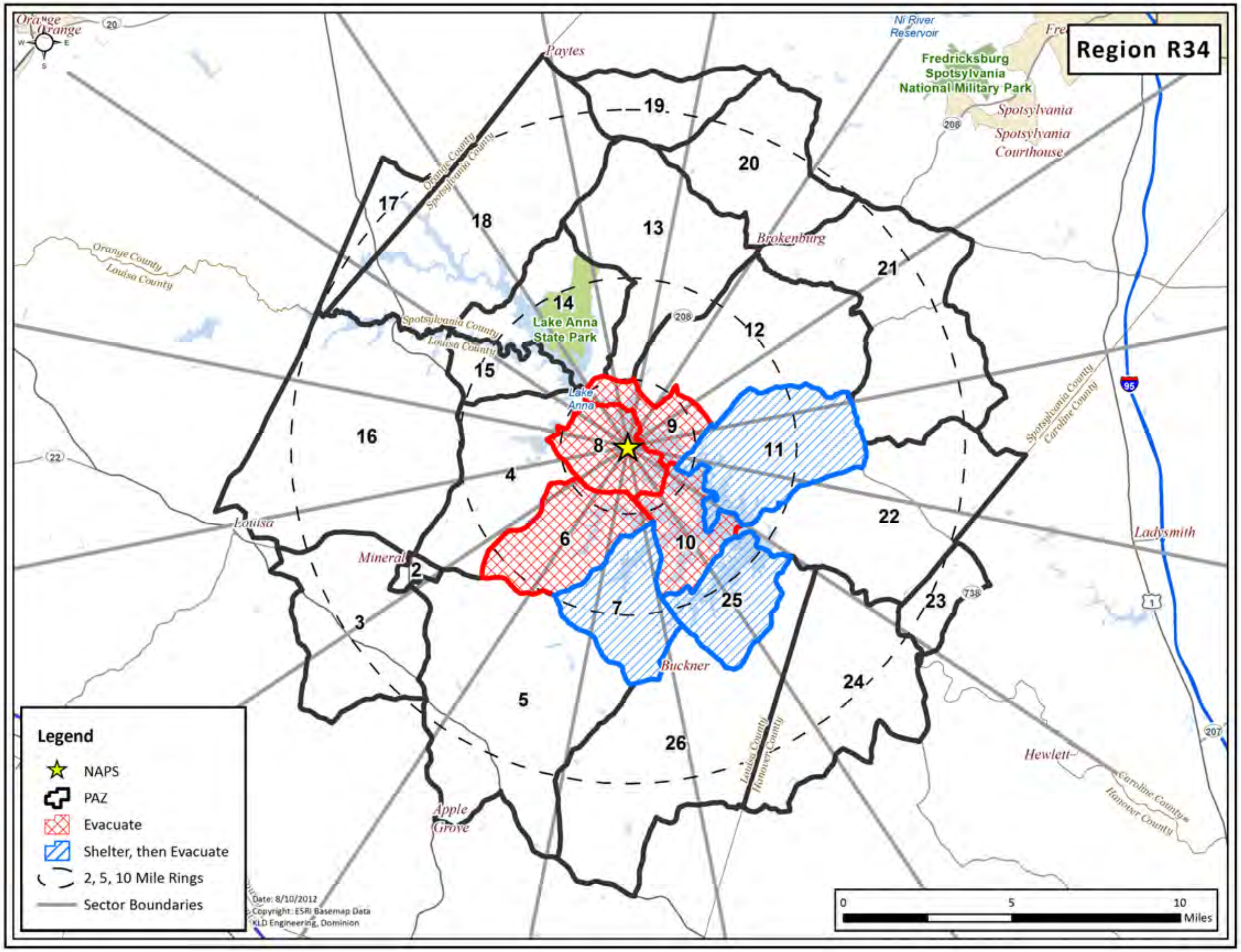


Figure H-34. Region R34

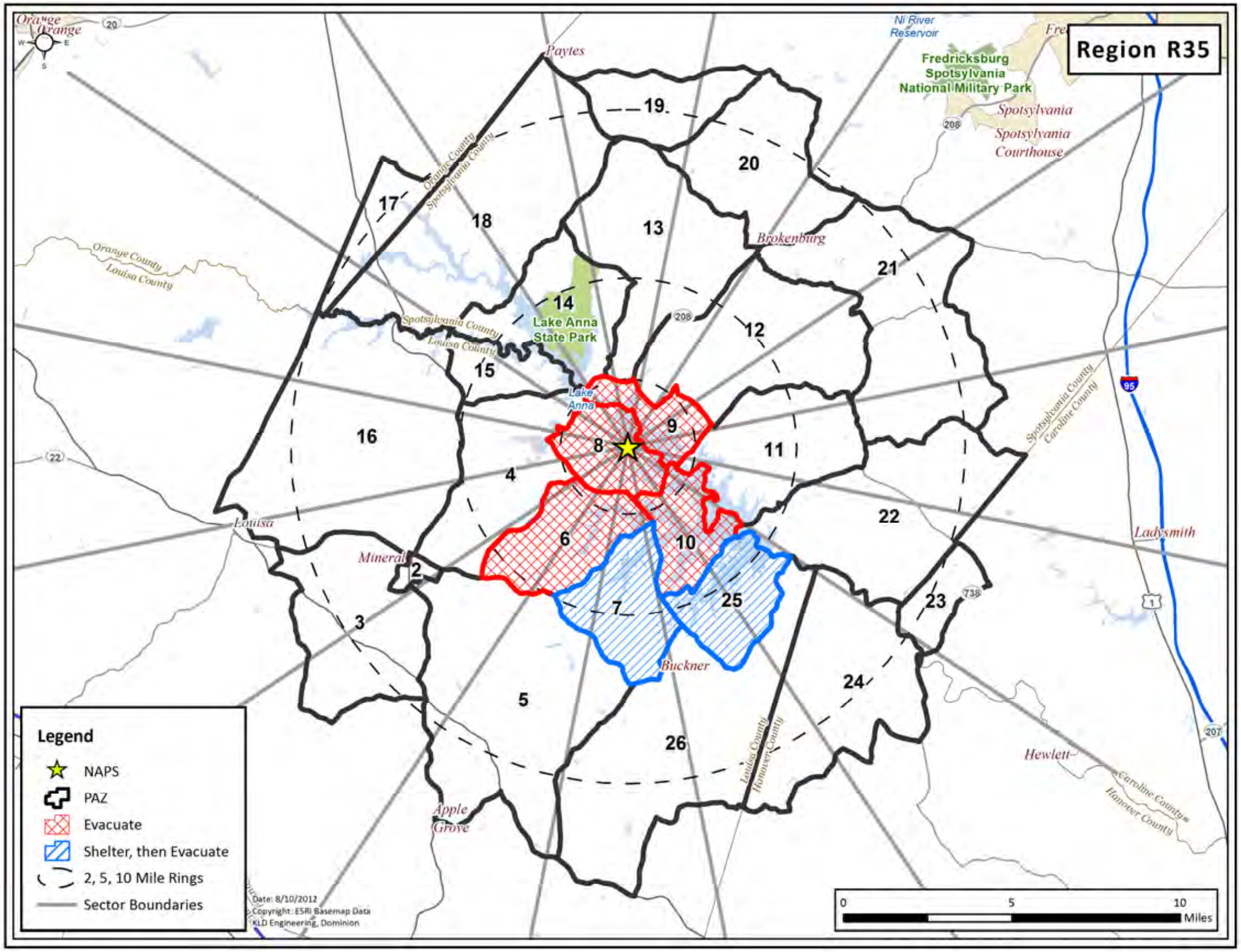


Figure H-35. Region R35

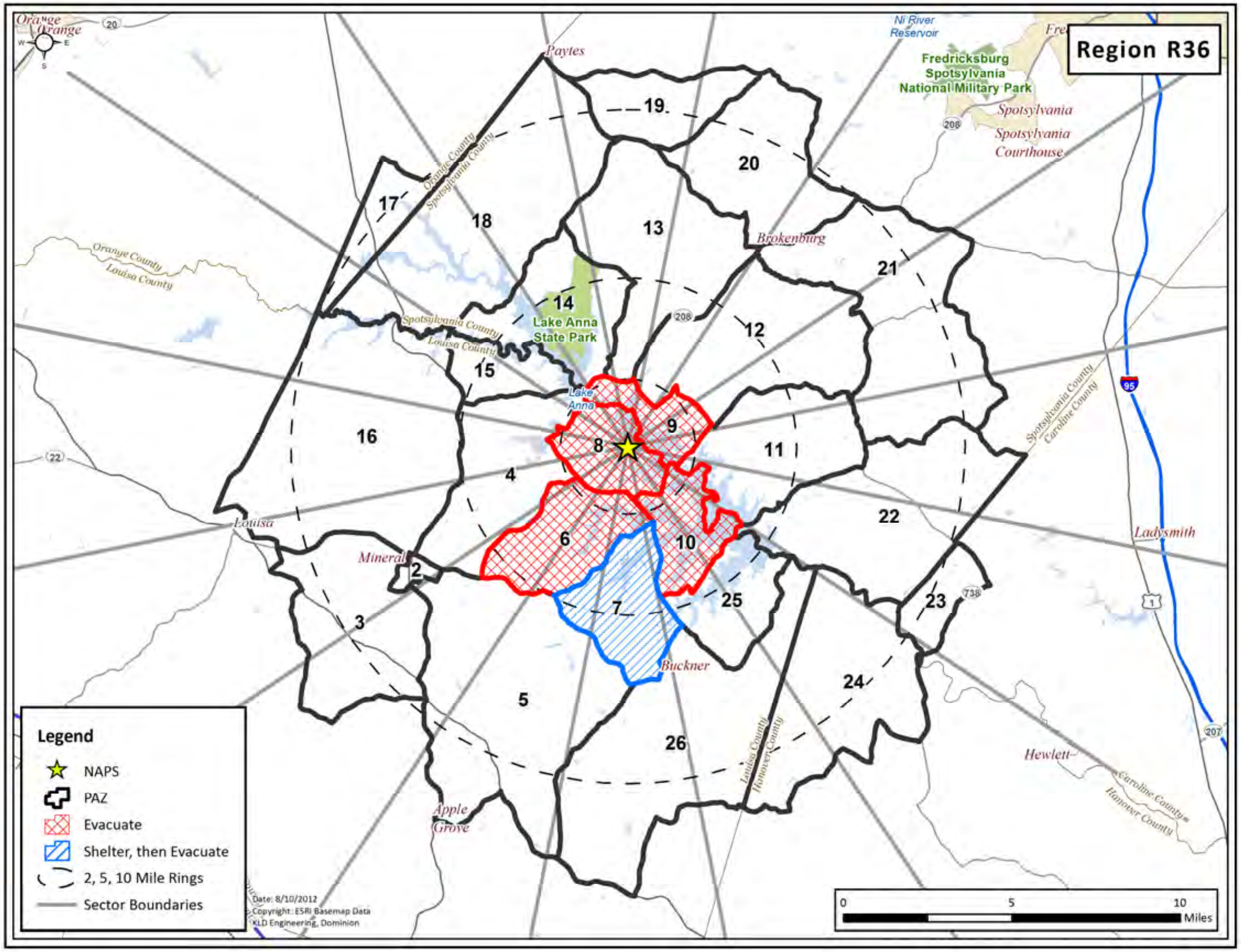


Figure H-36. Region R36

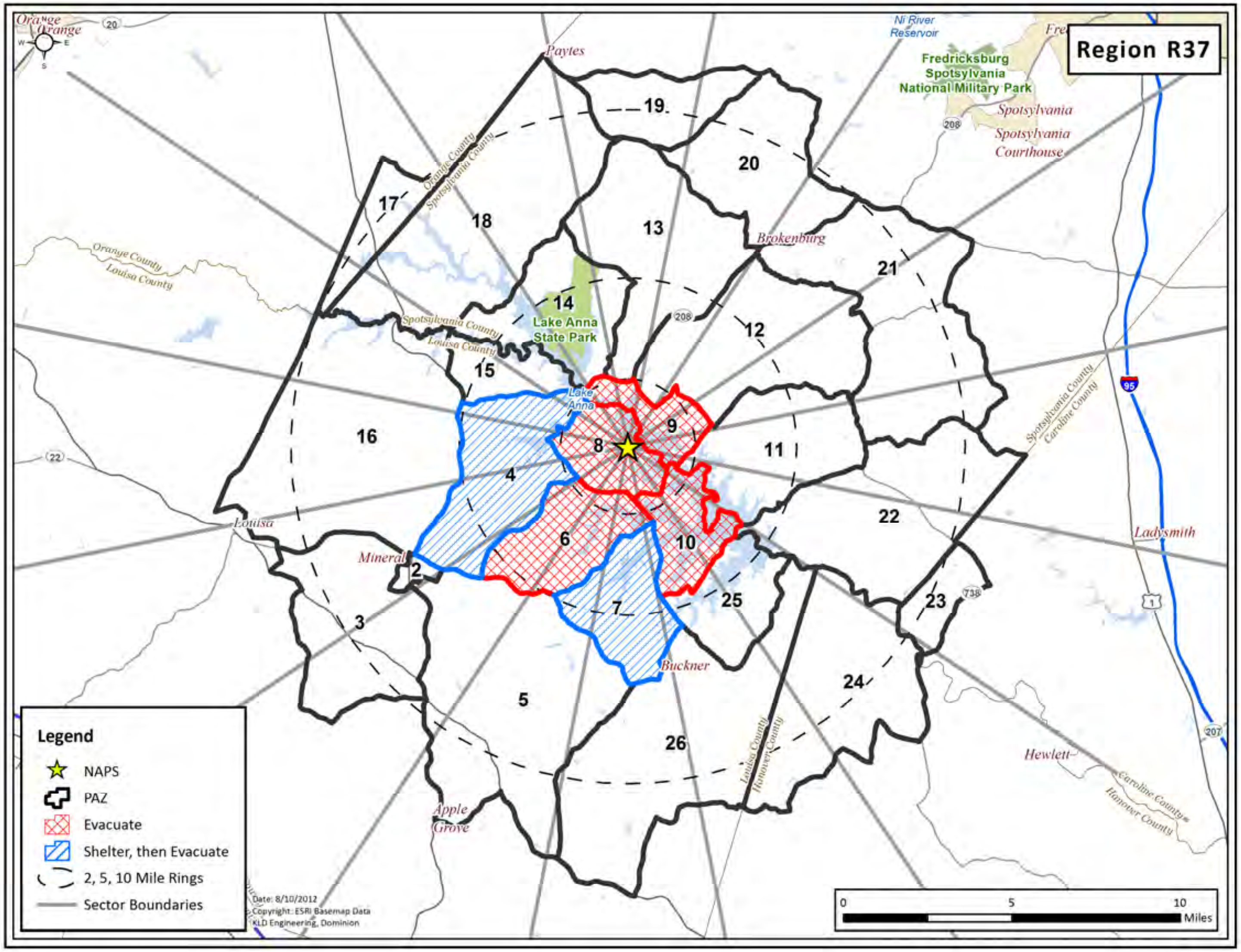


Figure H-37. Region R37

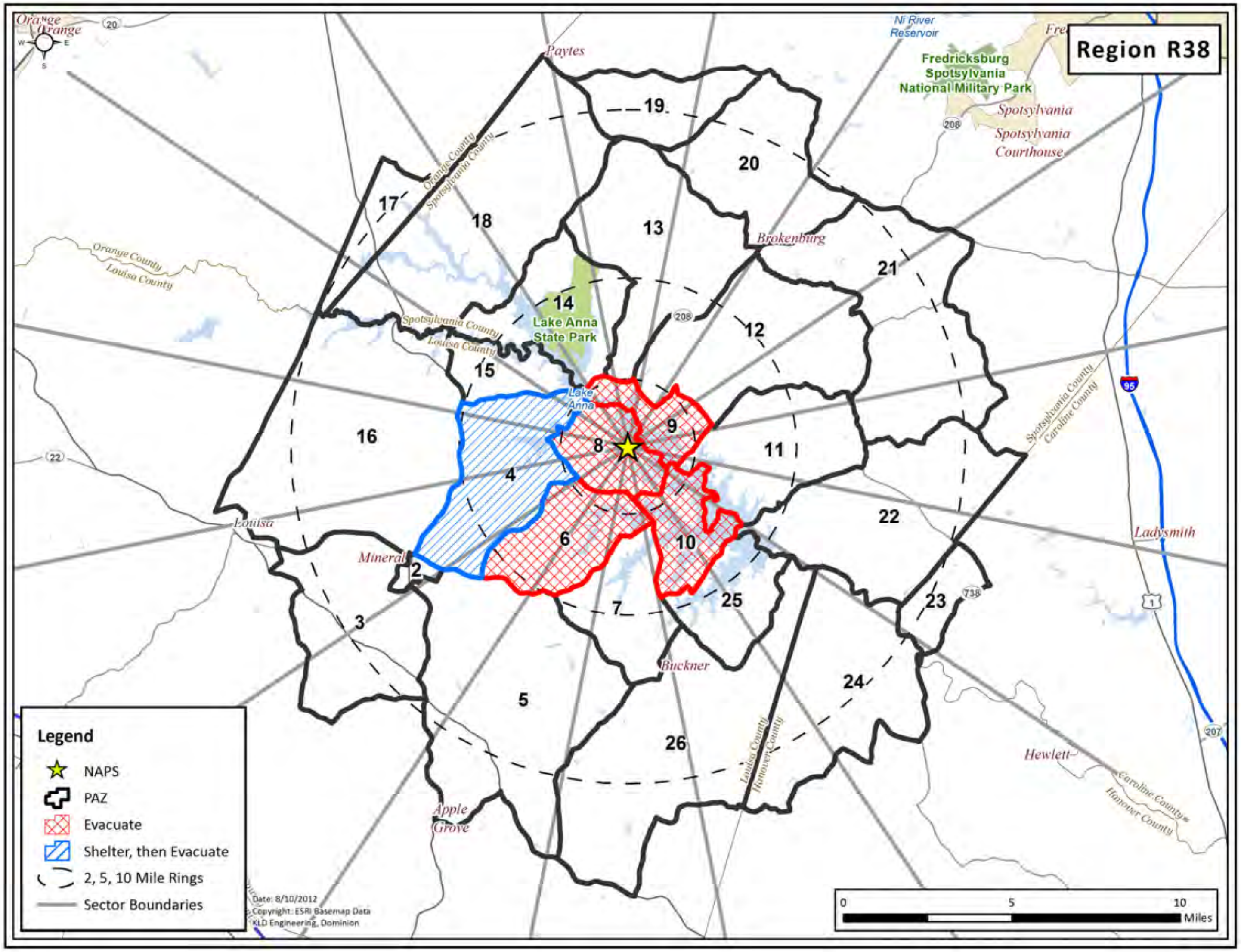


Figure H-38. Region R38

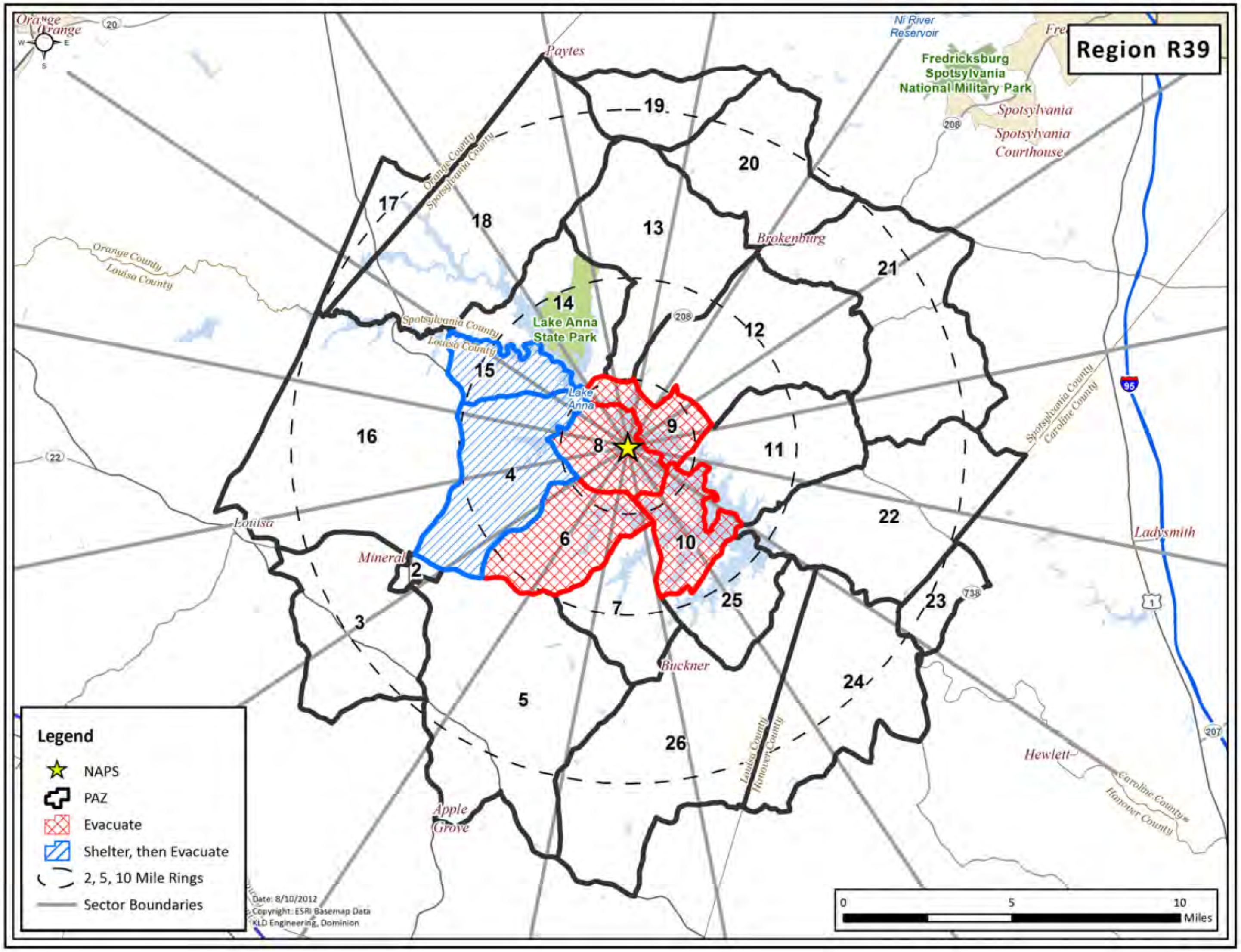


Figure H-39. Region R39

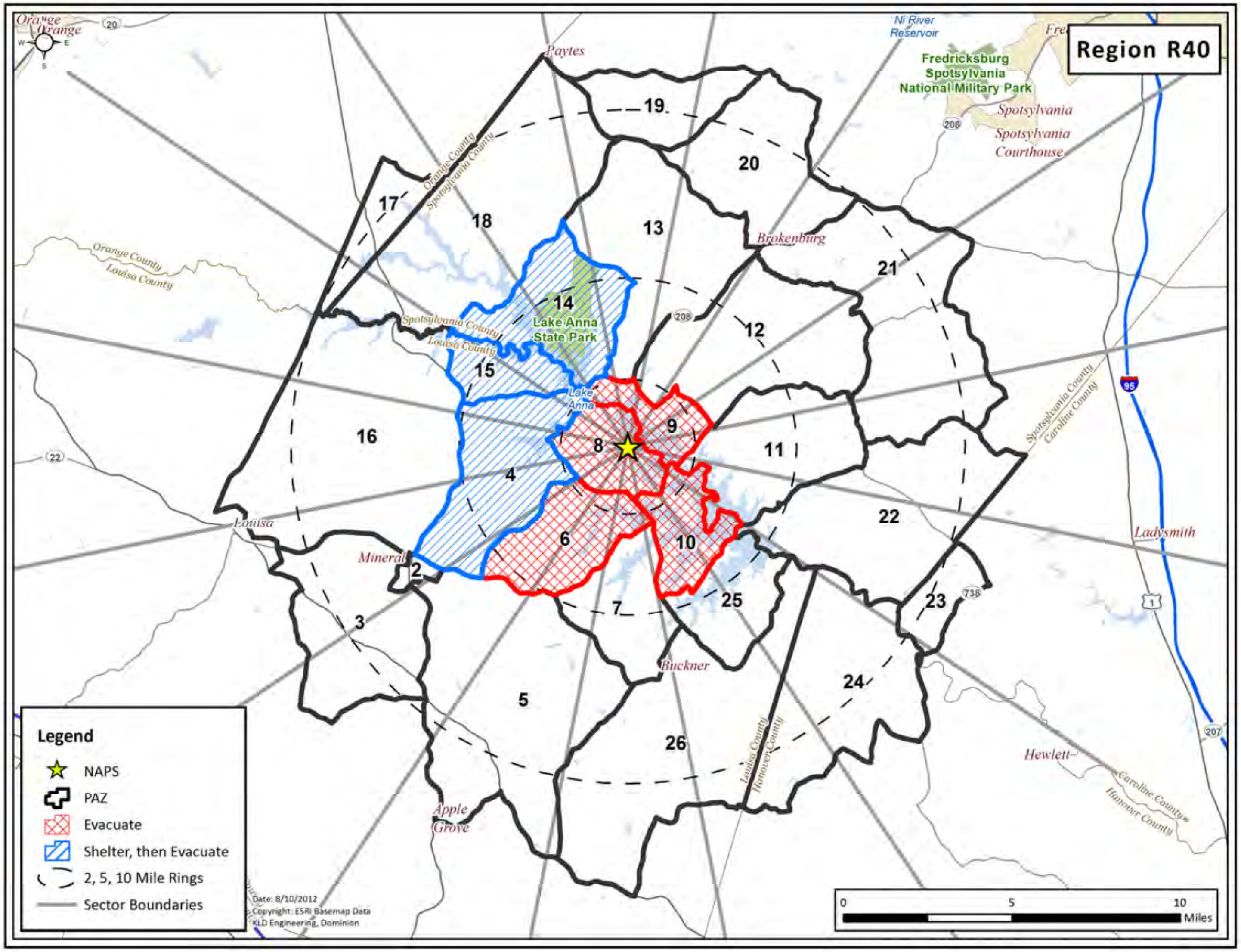


Figure H-40. Region R40

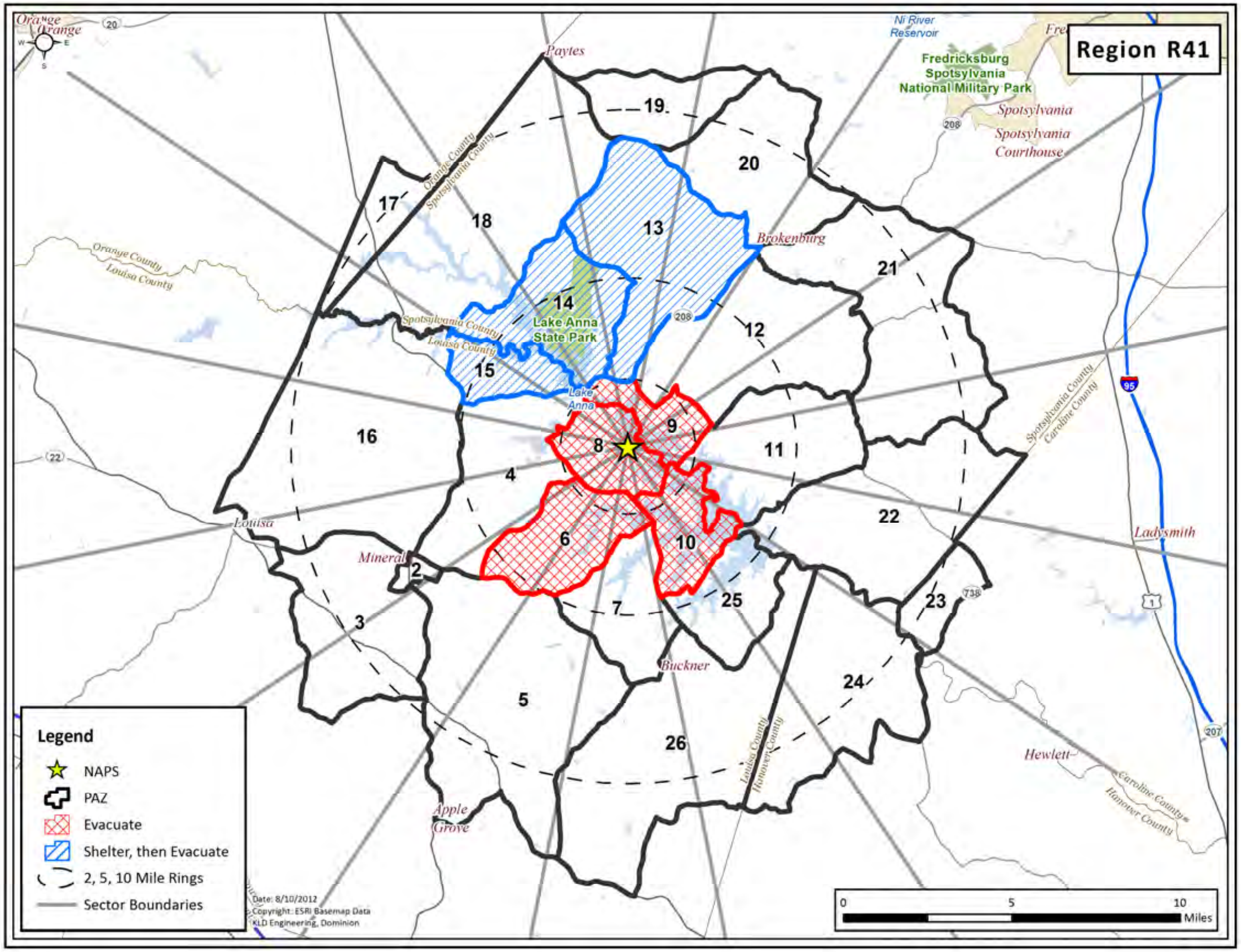


Figure H-41. Region R41

APPENDIX J

Representative Inputs to and Outputs from the DYNEV II System

J. REPRESENTATIVE INPUTS TO AND OUTPUTS FROM THE DYNEV II SYSTEM

This appendix presents data input to and output from the DYNEV II System. Table J-1 provides the volume and queues for the ten highest volume signalized intersections in the study area. A residual queue, existing at the start of the RED signal indication, indicates that the demand could not be entirely served by the GREEN phase. No residual queue indicates that the traffic movement is under-saturated (i.e., not congested) throughout the duration of evacuation. Refer to Table K-2 and the figures in Appendix K for a map showing the geographic location of each intersection.

Table J-2 provides source (vehicle loading) and destination information for several roadway segments (links) in the analysis network. Refer to Table K-1 and the figures in Appendix K for a map showing the geographic location of each link.

Table J-3 provides network–wide statistics (average travel time, average speed and number of vehicles) for an evacuation of the entire EPZ (Region R03) for each scenario. As expected, rain and snow reduce the average speed and increase the average travel time; for example compare the winter Scenarios 6, 7 and 8. The roadway impact and special event scenarios have slower average speeds than their equivalent normal conditions scenarios.

Table J-4 provides statistics (average speed and travel time) for the major evacuation routes – US 522, SR 208, SR 738 and US 33 – for an evacuation of the entire EPZ (Region R03) under Scenario 1 conditions. As discussed in Section 7.3 and shown in Figures 7-3 through 7-6, there is essentially no congestion in the EPZ throughout the duration of the evacuation. As such, the average speeds on the main evacuation routes are essentially unaffected.

Table J-5 provides the number of vehicles discharged and the cumulative percent of total vehicles discharged for each link exiting the analysis network, for an evacuation of the entire EPZ (Region R03) under Scenario 1 conditions. Refer to Table K-1 and the figures in Appendix K for a map showing the geographic location of each link.

Figure J-1 through Figure J-14 plot the trip generation time versus the ETE for each of the 14 Scenarios considered. The distance between the trip generation and ETE curves is the travel time. Plots of trip generation versus ETE are indicative of the level of traffic congestion during evacuation. For low population density sites, the curves are close together, indicating short travel times and minimal traffic congestion. For higher population density sites, the curves are farther apart indicating longer travel times and the presence of traffic congestion. As seen in Figure J-1 through Figure J-14, the curves are close together as a result of the minimal traffic congestion in the EPZ, which was discussed in detail in Section 7.3.

Table J-1. Characteristics of the Ten Highest Volume Signalized Intersections

Node	Location	Intersection Control	Approach (Up Node)	Total Volume (Veh)	Max. Turn Queue (Veh)
288	US 1 & CR 606	Actuated	289	1,196	0
			12	863	0
			261	699	0
			TOTAL	2,758	-
166	US 33 & SR 628/Rosewood Ave	Actuated	170	109	0
			66	1,338	0
			219	1,245	0
			TOTAL	2,692	-
127	US 1 & SR 639	Actuated	126	798	0
			133	953	0
			134	903	0
			TOTAL	2,654	-
2	US 522 and SR 20	Actuated	194	638	0
			195	1,895	0
			198	107	0
			TOTAL	2,640	-
9	Lake Anna Pkwy & SR 208	TCP Actuated	497	1,690	0
			385	762	0
			TOTAL	2,452	-
66	US33/SR 22 & SR 208/Courthouse Rd	Actuated	65	2,168	0
			166	161	0
			168	18	0
			TOTAL	2,347	-
170	US 33 & Courthouse Sq	Actuated	67	0	0
			166	1,526	0
			180	811	0
			TOTAL	2,337	-
65	SR 208/SR 22 & US 33	Actuated	519	1,973	0
			313	136	0
			66	0	0
			TOTAL	2,109	-
264	US 1 & CR 608	Actuated	263	1,102	0
			265	498	0
			255	493	0
			TOTAL	2,093	-
302	US 1 & SR 207/SR 658	Actuated	287	420	0
			117	973	0
			613	0	0
			303	501	0
			TOTAL	1,894	-

Table J-2. Sample Simulation Model Input

Link Number	Vehicles Entering Network on this Link	Directional Preference	Destination Nodes	Destination Capacity
81	44	SW	8070	1,698
			8073	1,698
			8330	4,500
125	80	S	8444	3,315
549	130	E	8169	3,810
			8146	6,750
			8226	3,810
801	295	N	8225	1,698
			8306	1,698
			8238	1,698
51	15	NW	8016	1,698
			8231	1,698
			8214	1,698
532	79	NE	8146	6,750
			8143	1,698
			8167	1,698
632	88	S	8444	3,315
124	20	S	8330	4,500
			8329	4,500
			8187	1,698
334	31	NW	8016	1,698
			8231	1,698
			8214	1,698
609	85	NE	8226	3,810
			8225	1,698
			8306	1,698

Table J-3. Selected Model Outputs for the Evacuation of the Entire EPZ (Region R03)

Scenario	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Network-Wide Average Travel Time (Min/Veh-Mi)	1.1	1.2	1.2	1.3	1.3	1.0	1.1	1.3	1.1	1.2	1.3	1.2	1.1	1.1
Network-Wide Average Speed (mph)	56.1	50.9	50.1	46.1	46.9	58.2	52.7	46.9	56.4	51.2	47.2	51.7	55.3	54.4
Total Vehicles Exiting Network	36,413	36,626	36,264	36,456	26,199	34,594	34,798	34,869	33,733	33,945	34,043	24,364	34,086	36,412

Table J-4. Average Speed (mph) and Travel Time (min) for Major Evacuation Routes (Region R03, Scenario 1)

		Elapsed Time (hours)									
		1		2		3		4		5	
Route Name	Length (miles)	Speed (mph)	Travel Time (min)	Speed	Travel Time	Speed	Travel Time	Speed	Travel Time	Speed	Travel Time
US 522 NB from SR 208	7.2	57.2	7.6	59.1	7.4	58.7	7.4	58.8	7.4	60.0	7.2
US 522 SB from Mineral	7.4	51.8	8.5	52.2	8.4	52.5	8.4	54.2	8.1	54.2	8.1
SR 208/SR 22 WB from Mineral	4.2	51.4	4.9	53.2	4.7	53.5	4.7	53.6	4.7	53.6	4.7
SR 208/Courthouse Rd EB from CR 601	10.8	52.2	12.4	53.1	12.2	52.7	12.3	53.6	12.1	55.9	11.6
SR 738/Partlow Rd NB from CR 657	8.2	46.1	10.6	46.3	10.6	47.0	10.4	47.1	10.4	48.1	10.2
SR 738/Partlow Rd SB from CR 657	6.0	48.8	7.3	48.2	7.4	48.1	7.5	48.4	7.4	49.3	7.3
US 33 EB from SR 768	14.3	58.9	14.6	58.9	14.6	59.1	14.5	59.9	14.3	60.0	14.3

Table J-5. Simulation Model Outputs at Network Exit Links for Region R03, Scenario 1

EPZ Exit Link	Elapsed Time (hours)				
	1	2	3	4	5
	Cumulative Vehicles Discharged by the Indicated Time				
	Cumulative Percent of Vehicles Discharged by the Indicated Time				
4	400	1,004	1,225	1,290	1,311
	3.40	3.55	3.54	3.59	3.60
22	346	852	1,027	1,081	1,099
	2.94	3.01	2.97	3.01	3.02
30	160	471	625	676	693
	1.36	1.67	1.80	1.88	1.90
31	102	369	491	516	523
	0.87	1.30	1.42	1.43	1.44
36	49	165	232	254	260
	0.41	0.58	0.67	0.71	0.71
38	188	539	711	769	785
	1.60	1.90	2.05	2.14	2.16
47	303	918	1,145	1,206	1,224
	2.57	3.24	3.31	3.35	3.36
65	209	560	749	800	816
	1.78	1.98	2.16	2.23	2.24
66	188	524	709	753	768
	1.60	1.85	2.05	2.09	2.11
80	129	324	412	438	447
	1.10	1.15	1.19	1.22	1.23
102	440	1,162	1,471	1,553	1,580
	3.75	4.10	4.25	4.32	4.34
103	205	542	716	779	797
	1.75	1.91	2.07	2.17	2.19
209	199	555	698	727	736
	1.69	1.96	2.02	2.02	2.02
304	2,361	4,803	5,492	5,510	5,516
	20.07	16.97	15.86	15.32	15.16
350	124	362	461	484	493
	1.06	1.28	1.33	1.35	1.36
356	130	447	578	605	613
	1.11	1.58	1.67	1.68	1.68
358	35	111	147	155	159
	0.30	0.39	0.42	0.43	0.44

EPZ Exit Link	Elapsed Time (hours)				
	1	2	3	4	5
	Cumulative Vehicles Discharged by the Indicated Time				
	Cumulative Percent of Vehicles Discharged by the Indicated Time				
371	287	783	1,107	1,216	1,251
	2.44	2.77	3.20	3.38	3.44
375	2,282	4,697	5,396	5,425	5,432
	19.40	16.59	15.58	15.09	14.93
407	1,144	2,675	3,061	3,118	3,135
	9.73	9.45	8.84	8.67	8.62
425	228	613	885	982	1,013
	1.94	2.16	2.55	2.73	2.78
456	1,175	2,837	3,270	3,338	3,357
	9.99	10.02	9.44	9.28	9.23
599	186	566	859	918	937
	1.58	2.00	2.48	2.55	2.58
600	436	1,185	1,551	1,659	1,693
	3.71	4.19	4.48	4.61	4.65
734	402	1,080	1,394	1,480	1,510
	3.42	3.82	4.02	4.12	4.15
788	52	162	216	231	235
	0.44	0.57	0.62	0.64	0.65

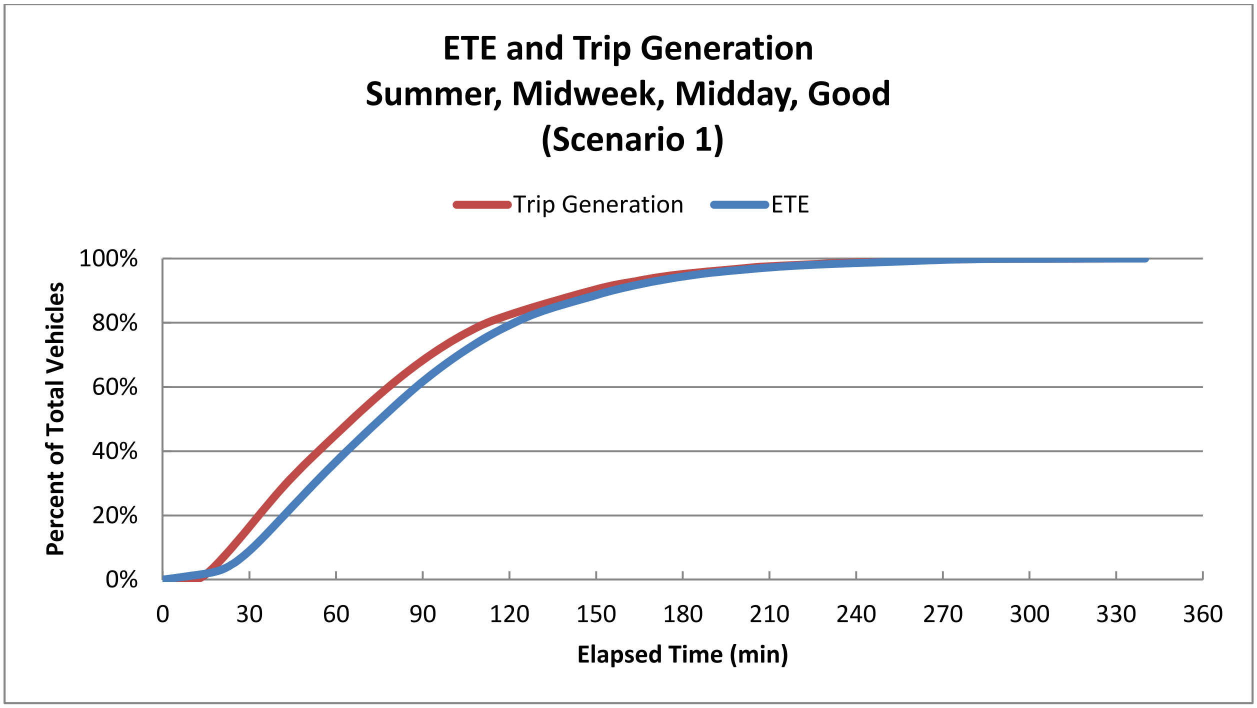


Figure J-1. ETE and Trip Generation: Summer, Midweek, Midday, Good Weather (Scenario 1)

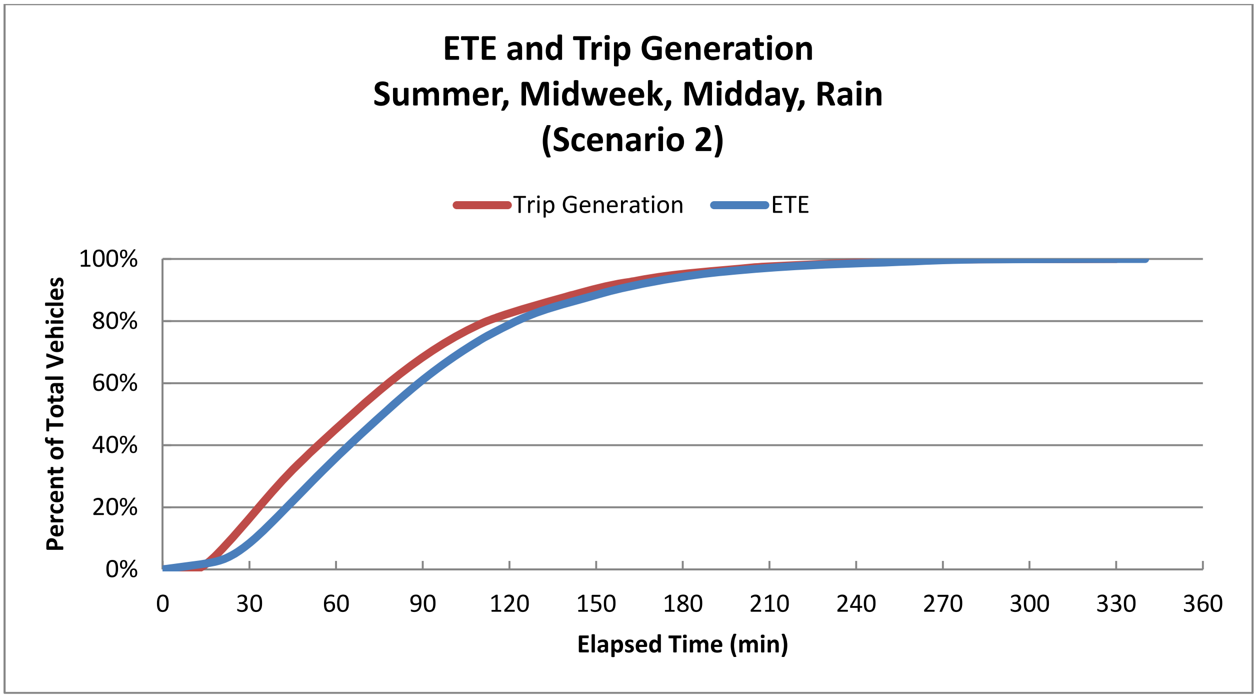


Figure J-2. ETE and Trip Generation: Summer, Midweek, Midday, Rain (Scenario 2)

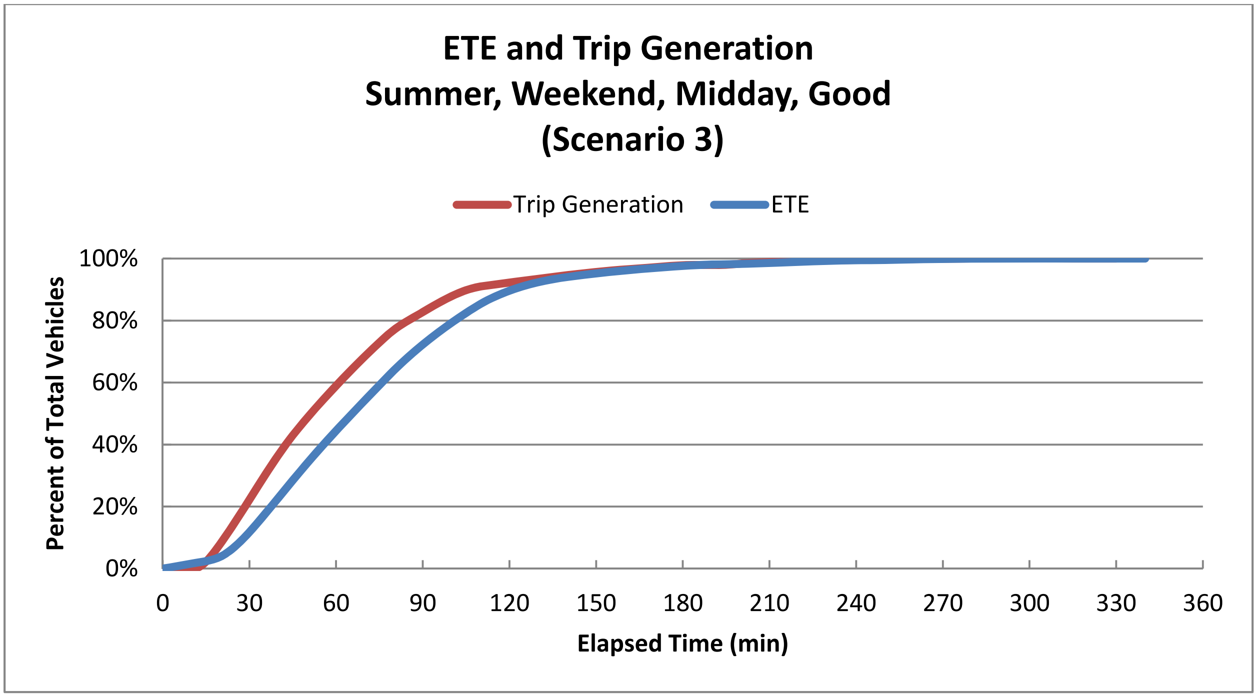


Figure J-3. ETE and Trip Generation: Summer, Weekend, Midday, Good Weather (Scenario 3)

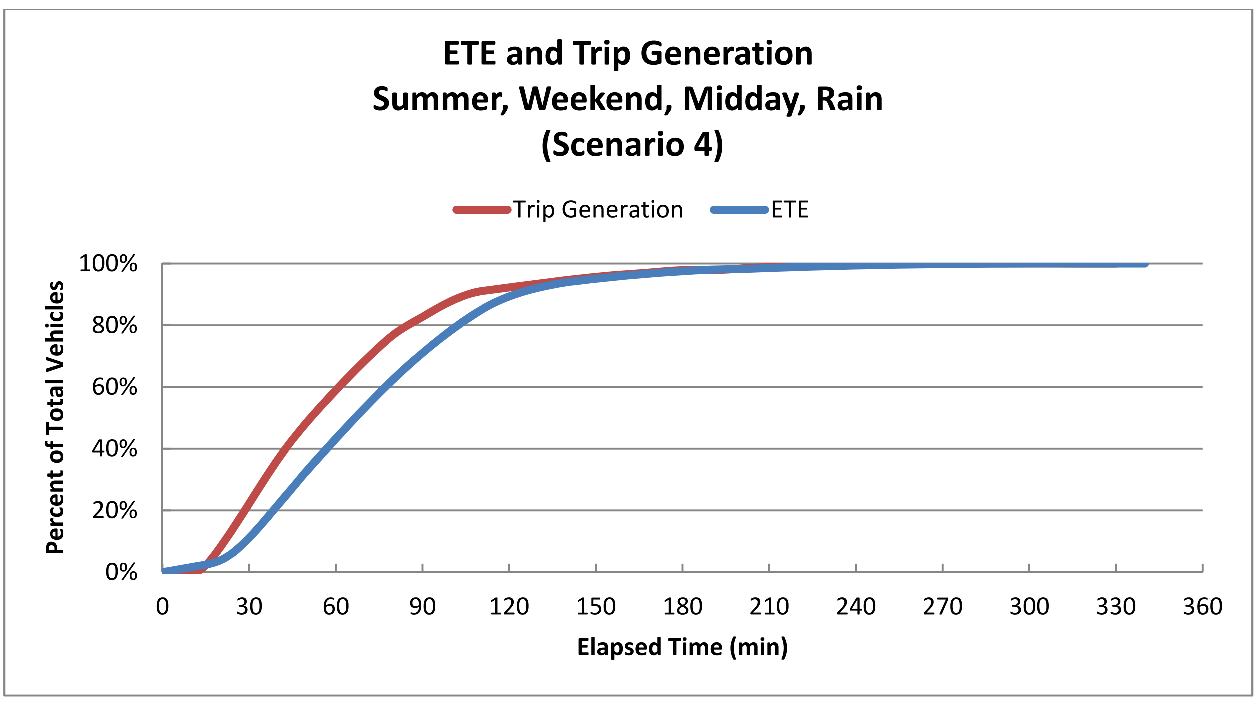


Figure J-4. ETE and Trip Generation: Summer, Weekend, Midday, Rain (Scenario 4)

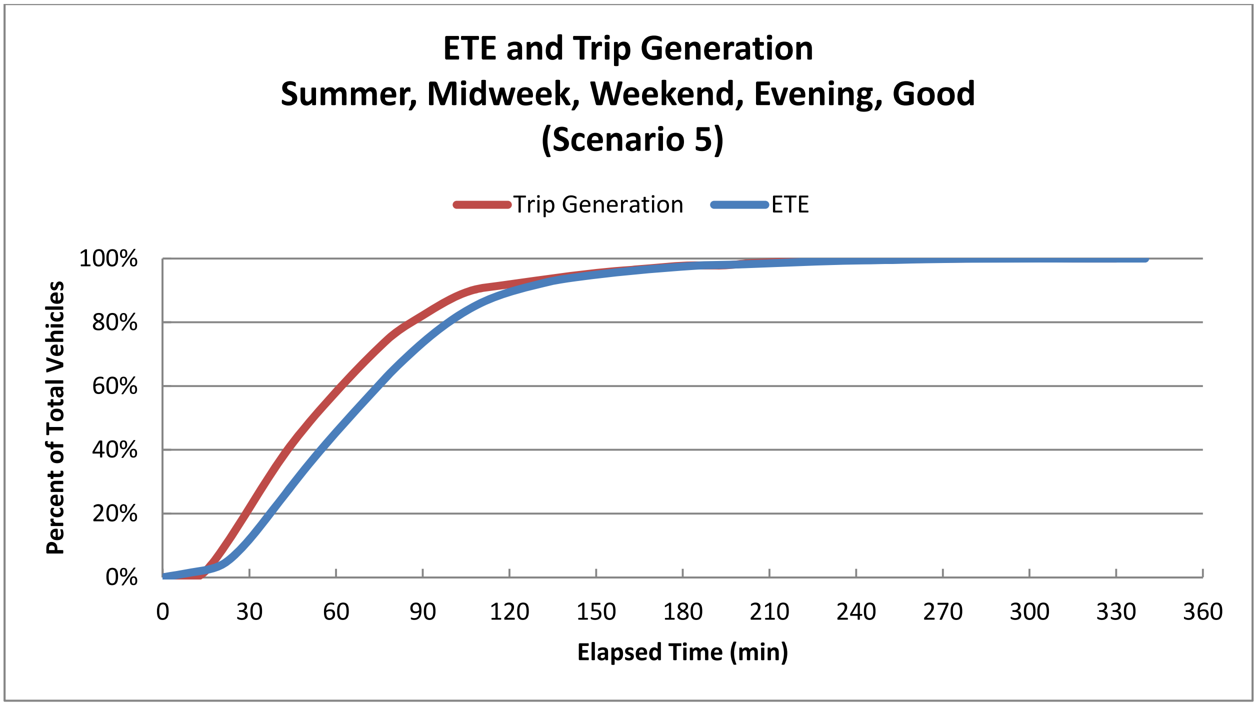


Figure J-5. ETE and Trip Generation: Summer, Midweek, Weekend, Evening, Good Weather (Scenario 5)

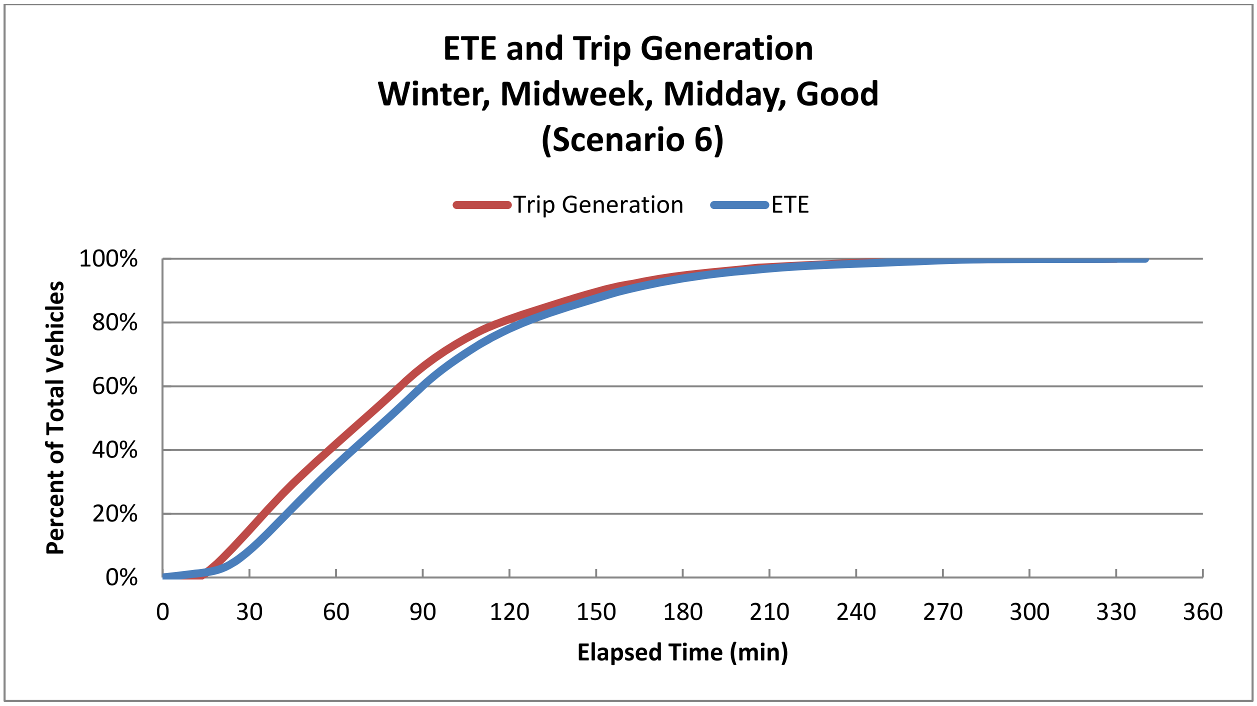


Figure J-6. ETE and Trip Generation: Winter, Midweek, Midday, Good Weather (Scenario 6)

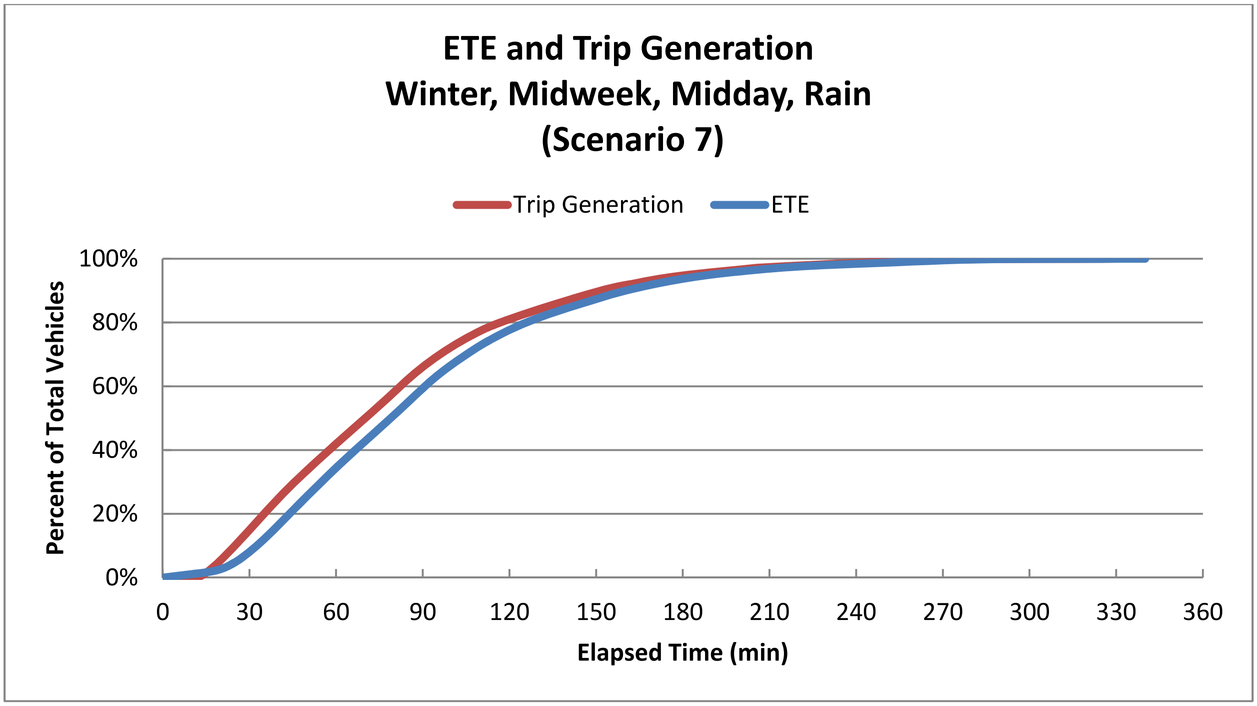


Figure J-7. ETE and Trip Generation: Winter, Midweek, Midday, Rain (Scenario 7)

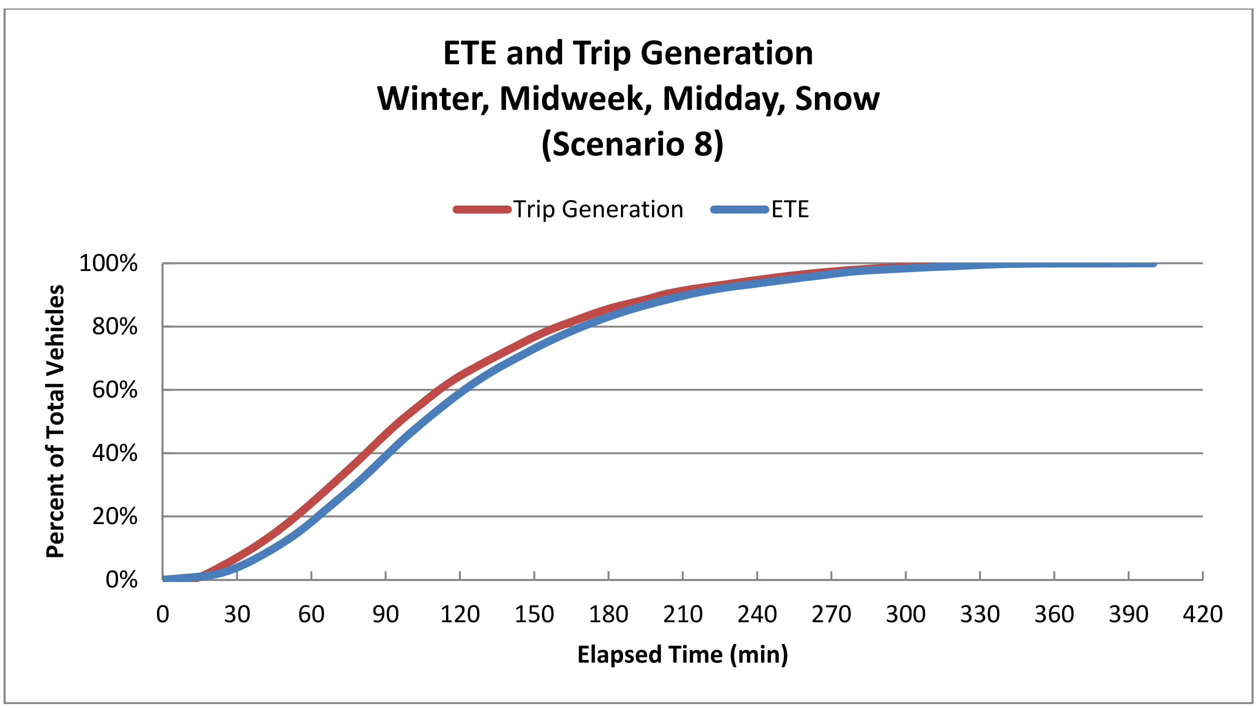


Figure J-8. ETE and Trip Generation: Winter, Midweek, Midday, Snow (Scenario 8)

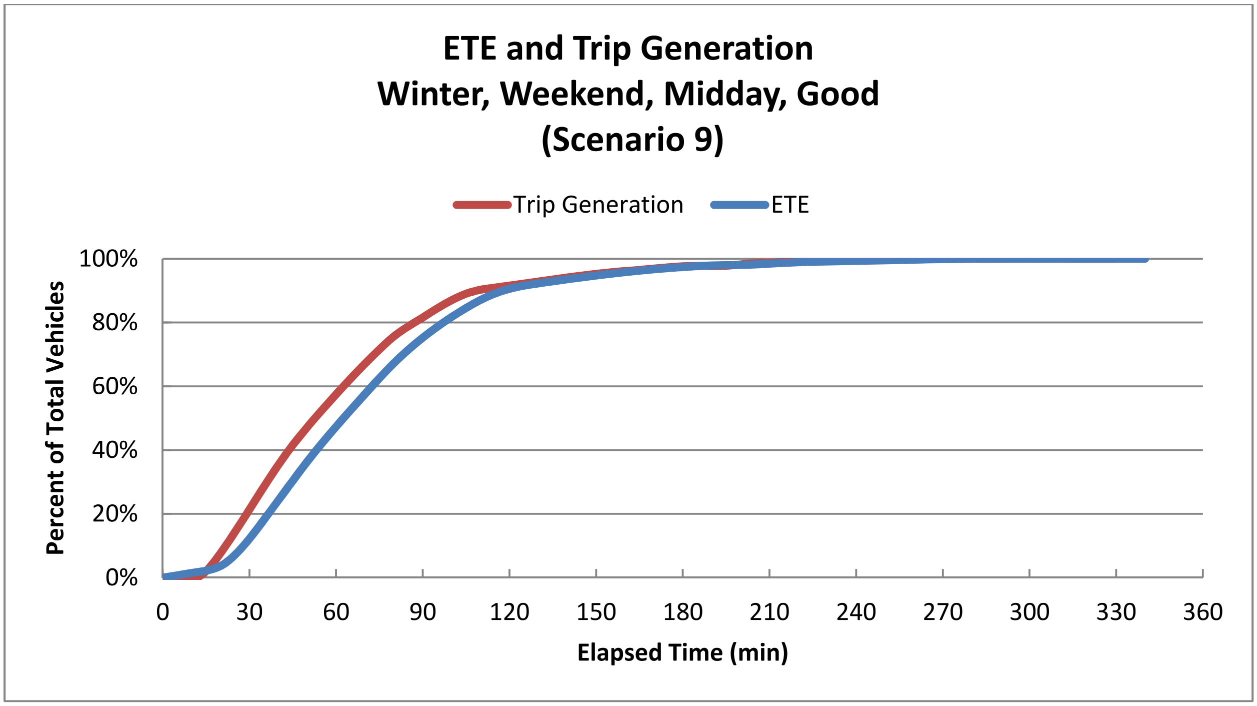


Figure J-9. ETE and Trip Generation: Winter, Weekend, Midday, Good Weather (Scenario 9)

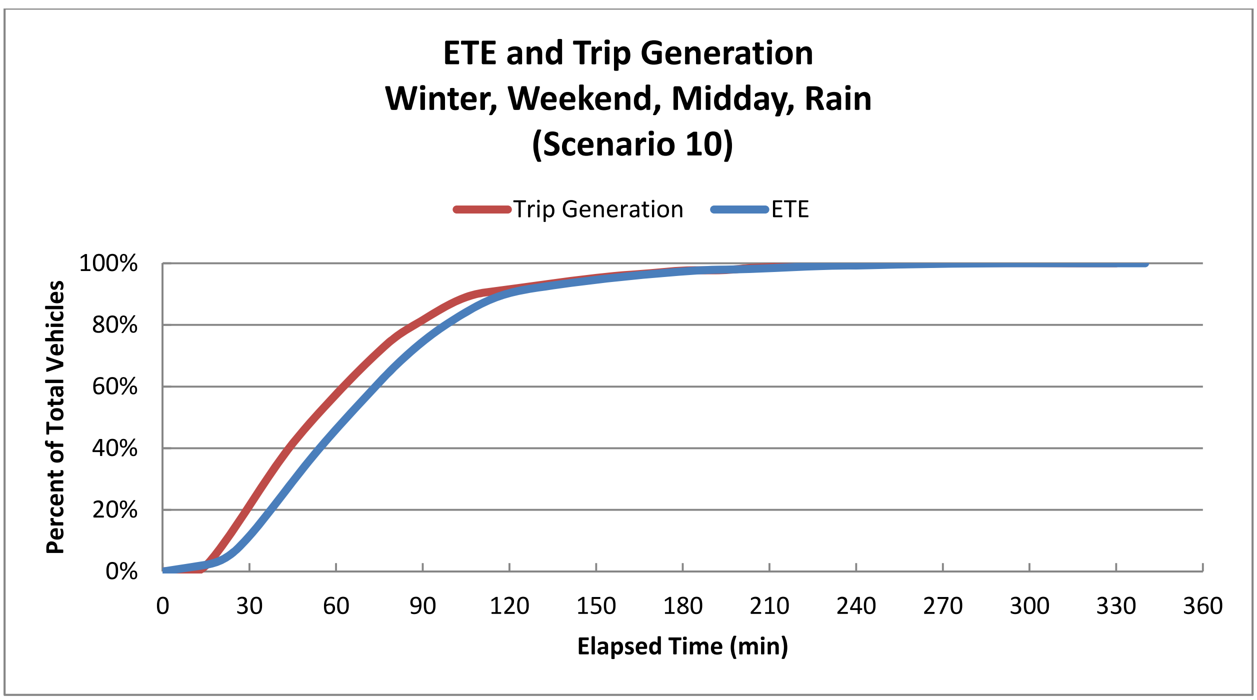


Figure J-10. ETE and Trip Generation: Winter, Weekend, Midday, Rain (Scenario 10)

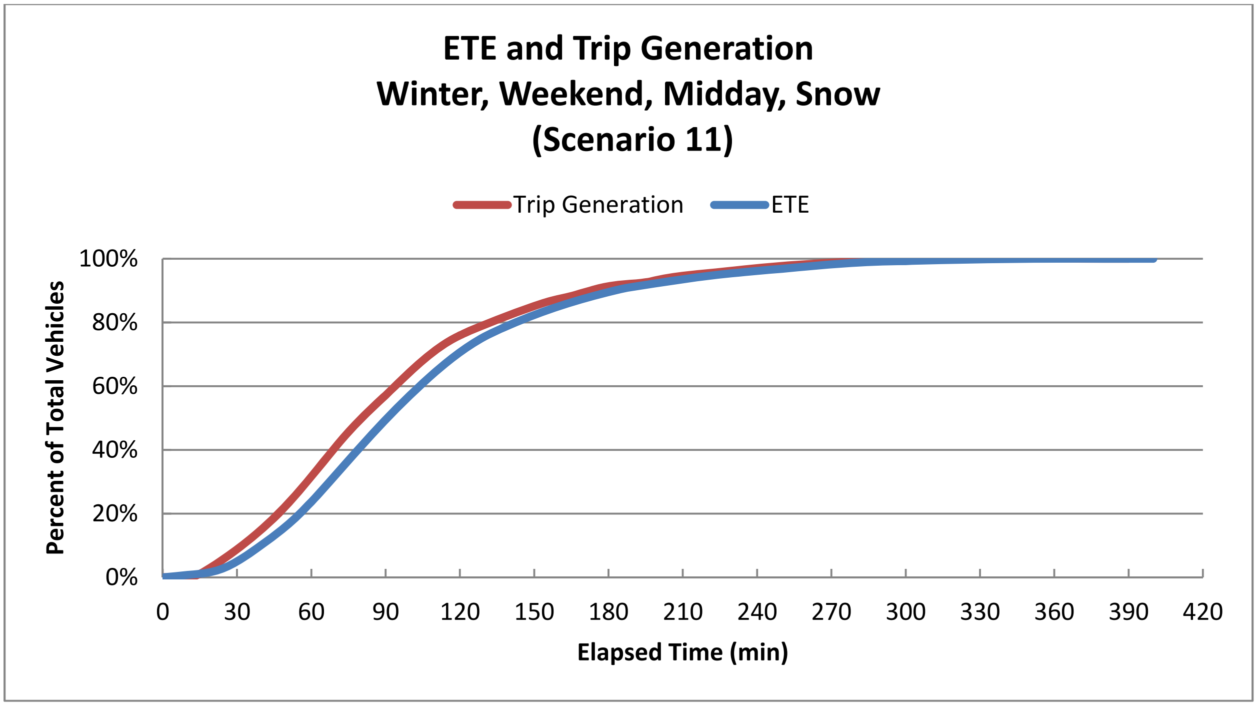


Figure J-11. ETE and Trip Generation: Winter, Weekend, Midday, Snow (Scenario 11)

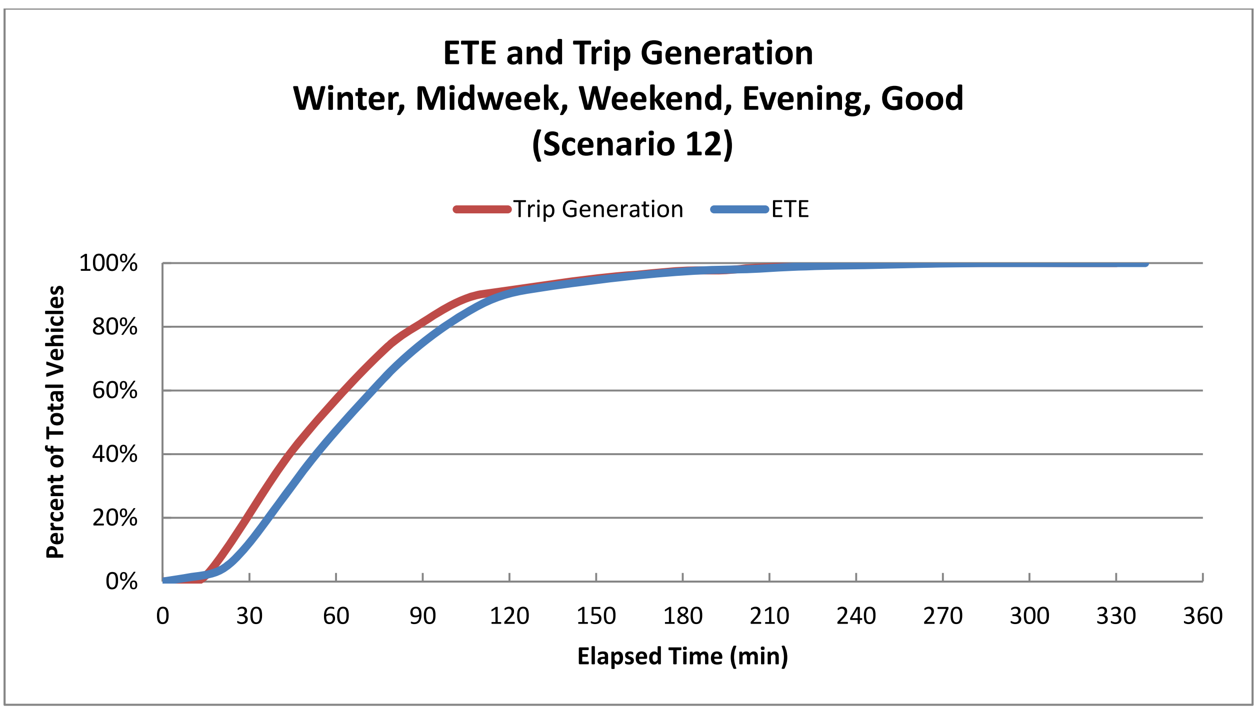


Figure J-12. ETE and Trip Generation: Winter, Midweek, Weekend, Evening, Good Weather (Scenario 12)

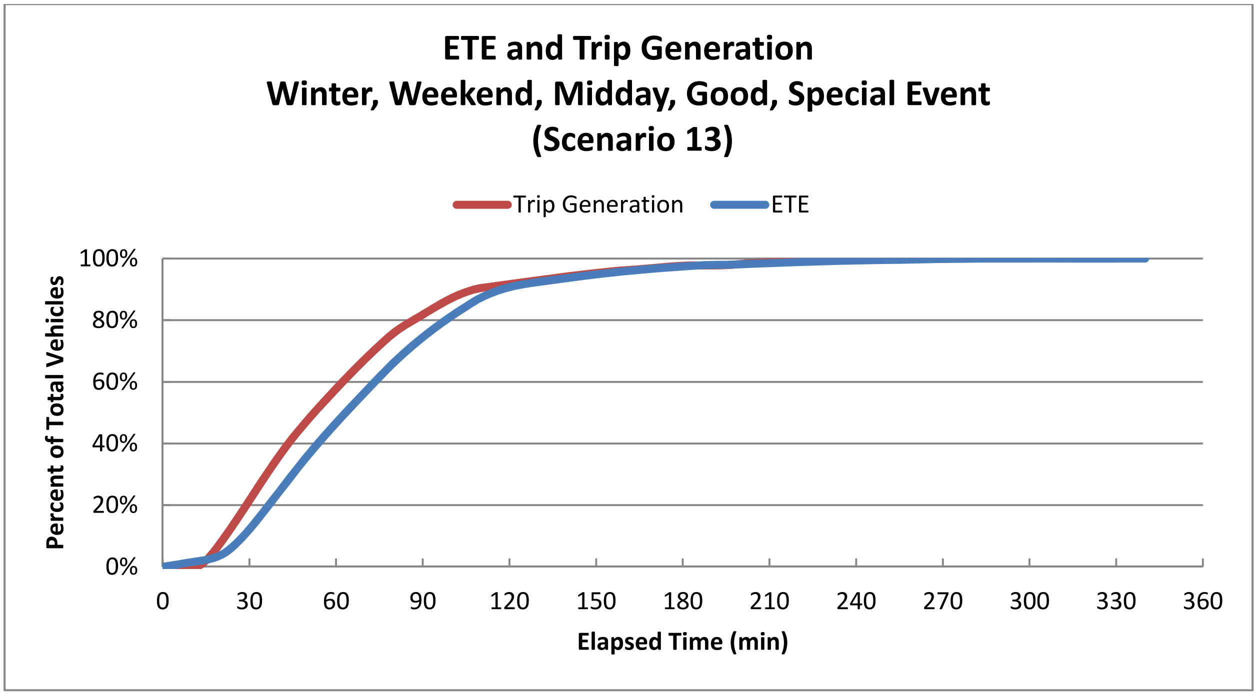


Figure J-13. ETE and Trip Generation: Summer, Weekend, Evening, Good Weather, Special Event (Scenario 13)

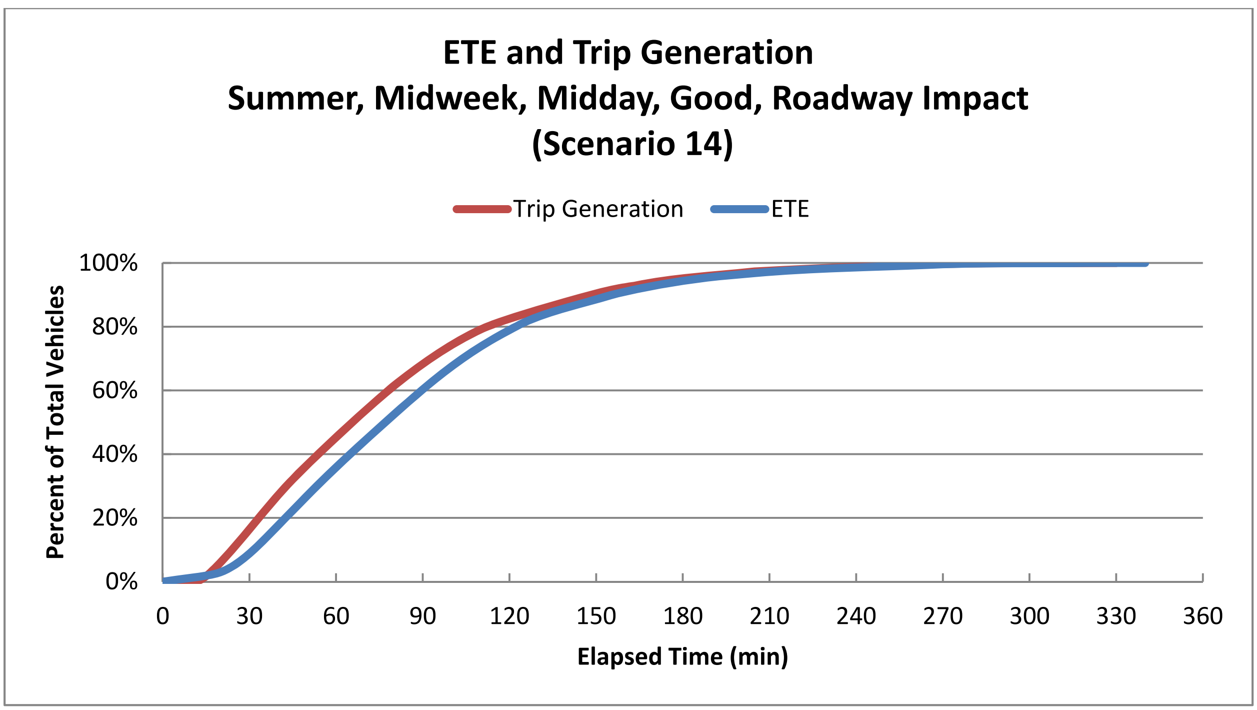


Figure J-14. ETE and Trip Generation: Summer, Midweek, Midday, Good Weather, Roadway Impact (Scenario 14)

APPENDIX K

Evacuation Roadway Network

K. EVACUATION ROADWAY NETWORK

As discussed in Section 1.3, a link-node analysis network was constructed to model the roadway network within the study area. Figure K-1 provides an overview of the link-node analysis network. The figure has been divided up into 37 more detailed figures (Figure K-2 through Figure K-38) which show each of the links and nodes in the network.

The analysis network was calibrated using the observations made during the field survey conducted in February 2012. Table K-1 lists the characteristics of each roadway section modeled in the ETE analysis. Each link is identified by its road name and the upstream and downstream node numbers. The geographic location of each link can be observed by referencing the grid map number provided in Table K-1. The roadway type identified in Table K-1 is based on the following criteria:

- Freeway: limited access highway, 2 or more lanes in each direction, high free flow speeds
- Freeway ramp: ramp on to or off of a limited access highway
- Major arterial: 3 or more lanes in each direction
- Minor arterial: 2 or more lanes in each direction
- Collector: single lane in each direction
- Local roadways: single lane in each direction, local roads with low free flow speeds

The term, "No. of Lanes" in Table K-1 identifies the number of lanes that extend throughout the length of the link. Many links have additional lanes on the immediate approach to an intersection (turn pockets); these have been recorded and entered into the input stream for the DYNEV II System.

As discussed in Section 1.3, lane width and shoulder width were not physically measured during the road survey. Rather, estimates of these measures were based on visual observations and recorded images.

Table K-2 identifies each node in the network that is controlled and the type of control (stop sign, yield sign, pre-timed signal, actuated signal, traffic control point) at that node. Uncontrolled nodes are not included in Table K-2. The location of each node can be observed by referencing the grid map number provided.

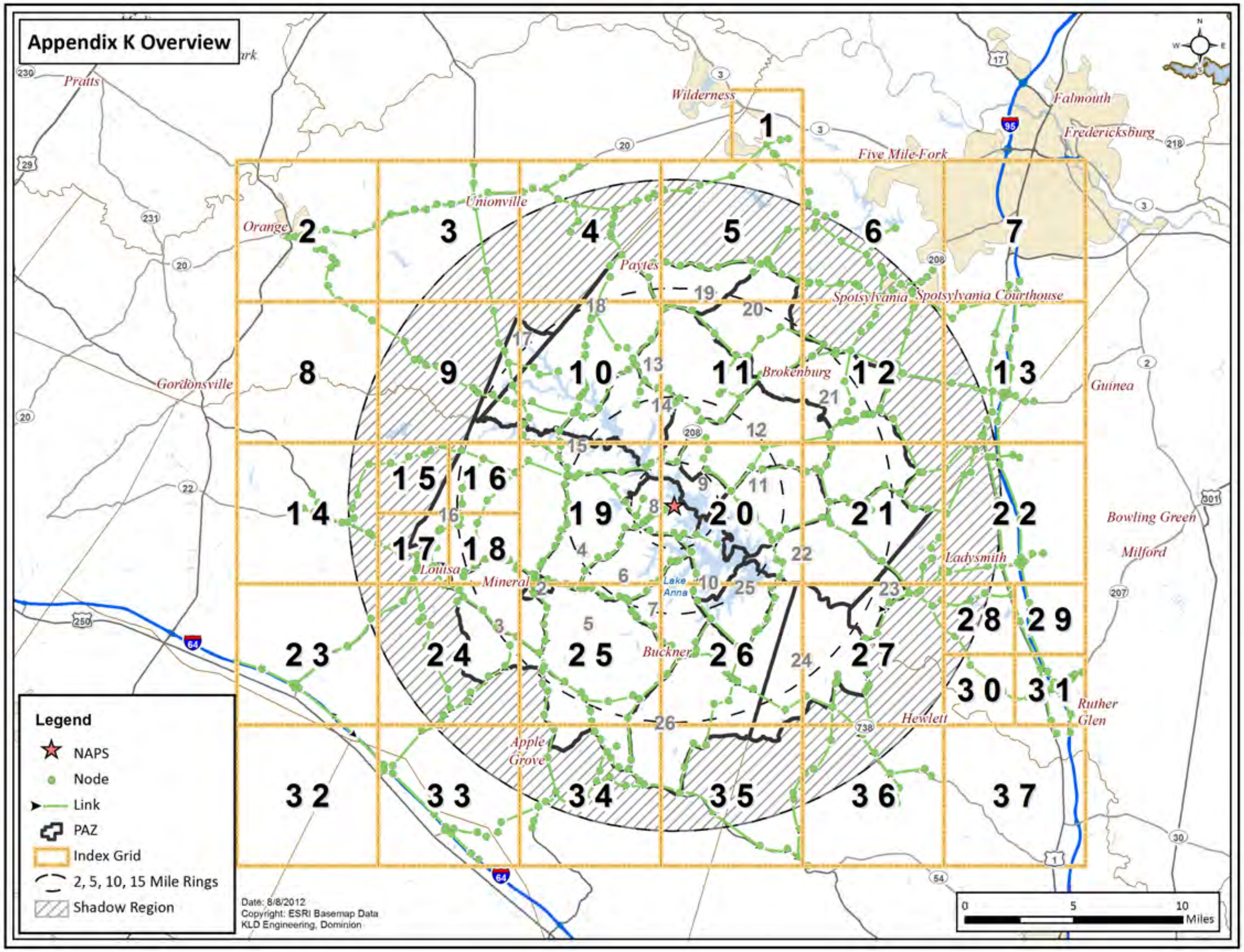


Figure K-1. NAPS Link-Node Analysis Network

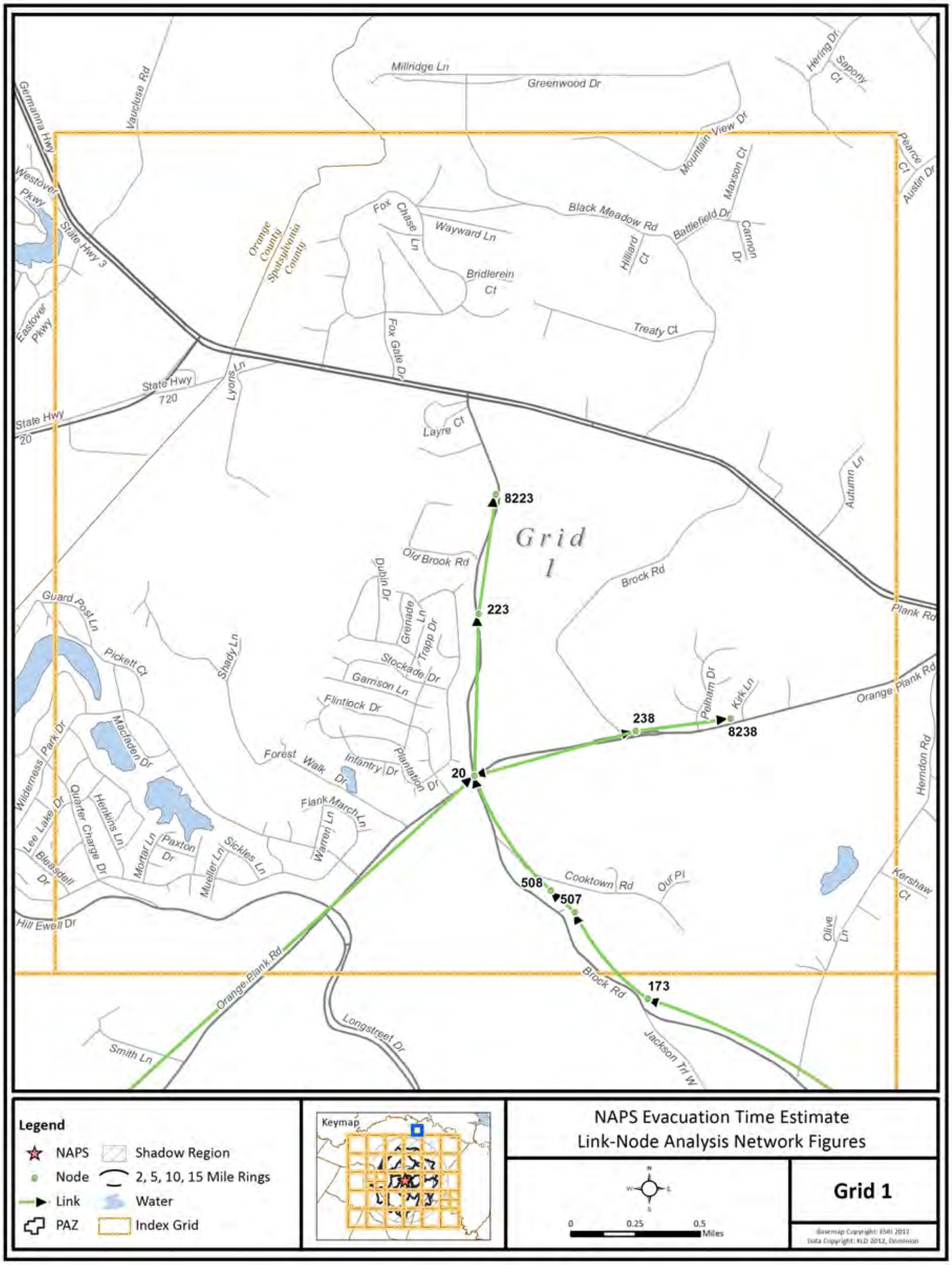


Figure K-2. Link-Node Analysis Network – Grid 1

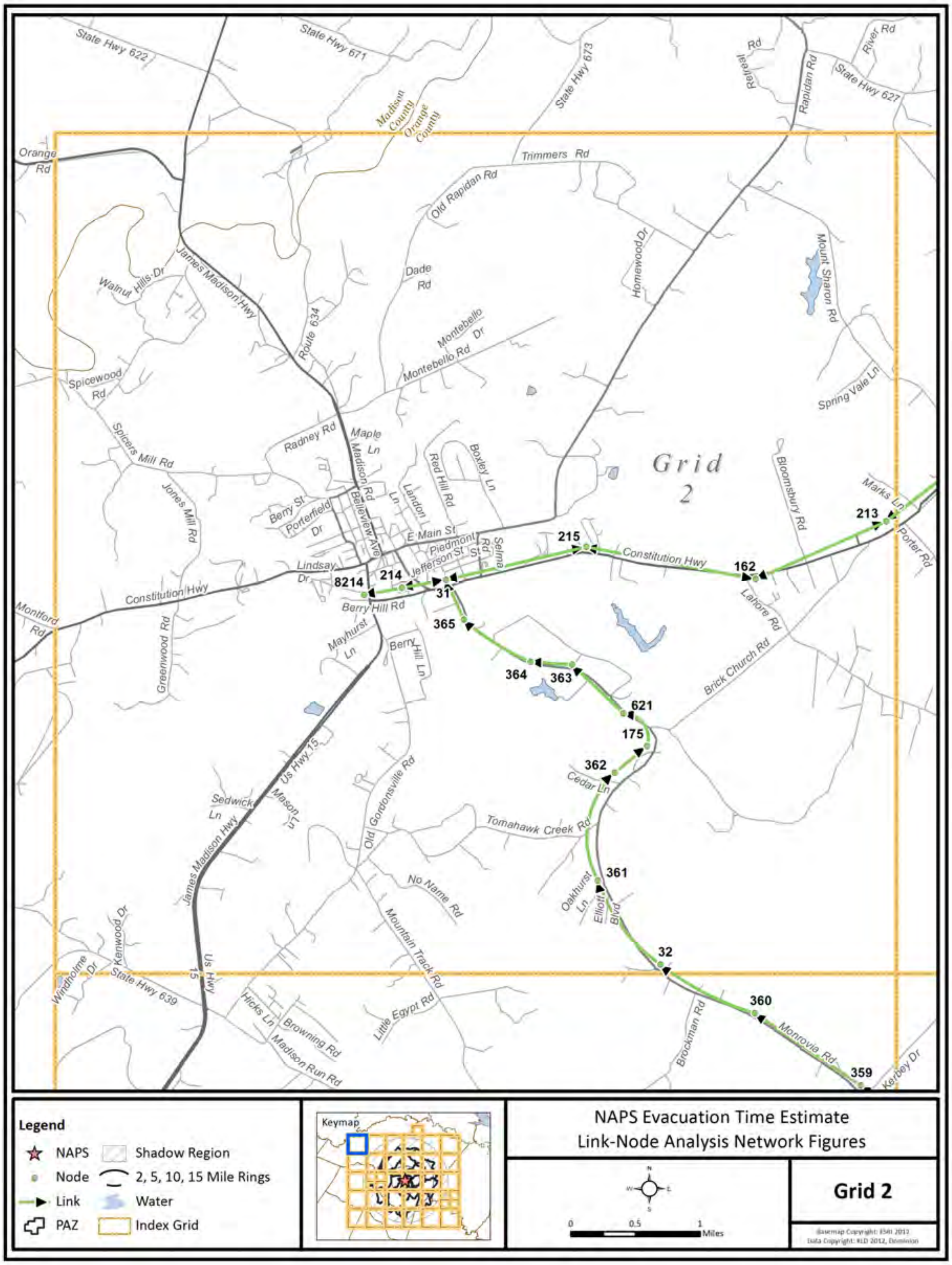


Figure K-3. Link-Node Analysis Network – Grid 2

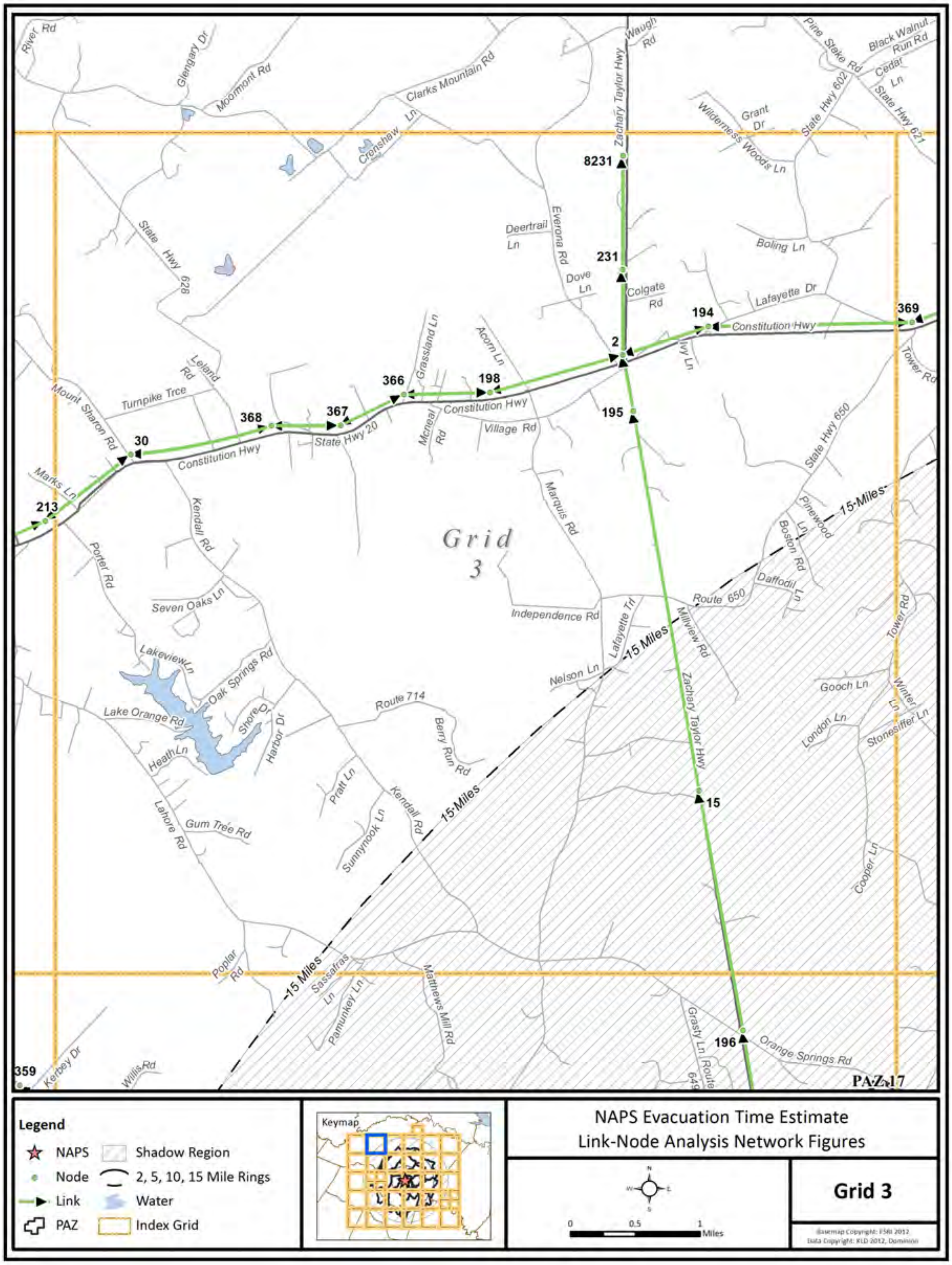


Figure K-4. Link-Node Analysis Network – Grid 3

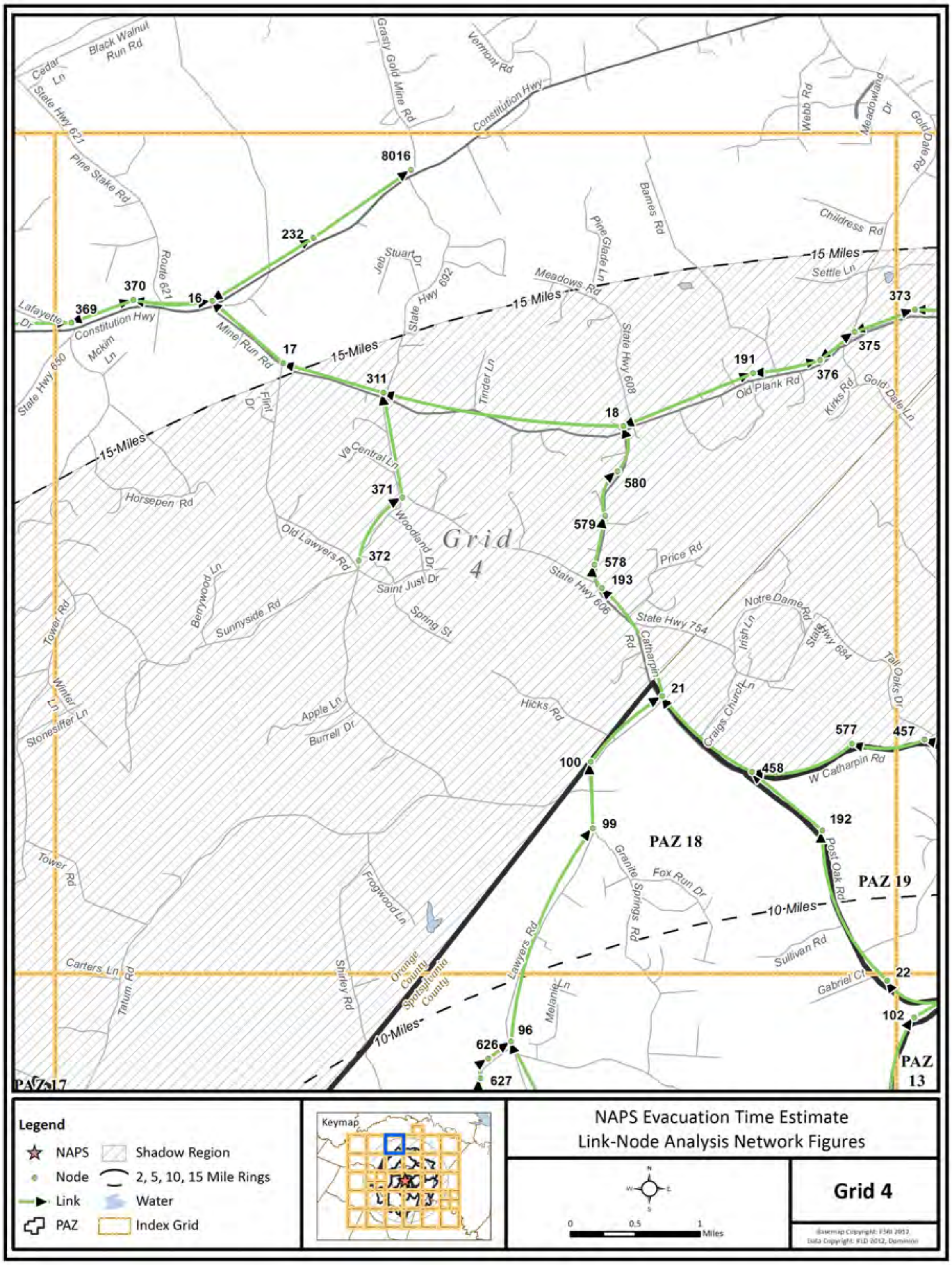


Figure K-5. Link-Node Analysis Network – Grid 4

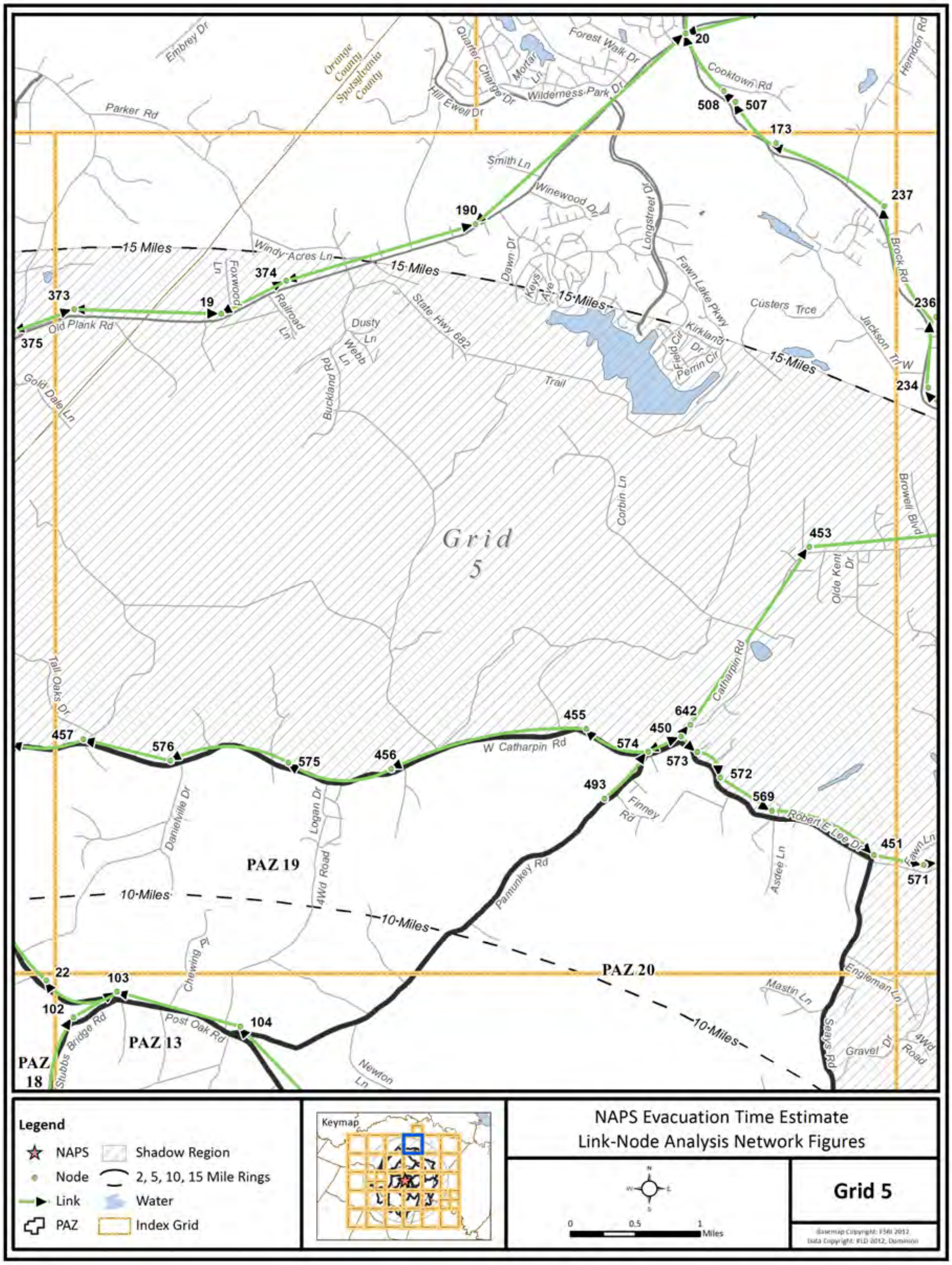


Figure K-6. Link-Node Analysis Network – Grid 5

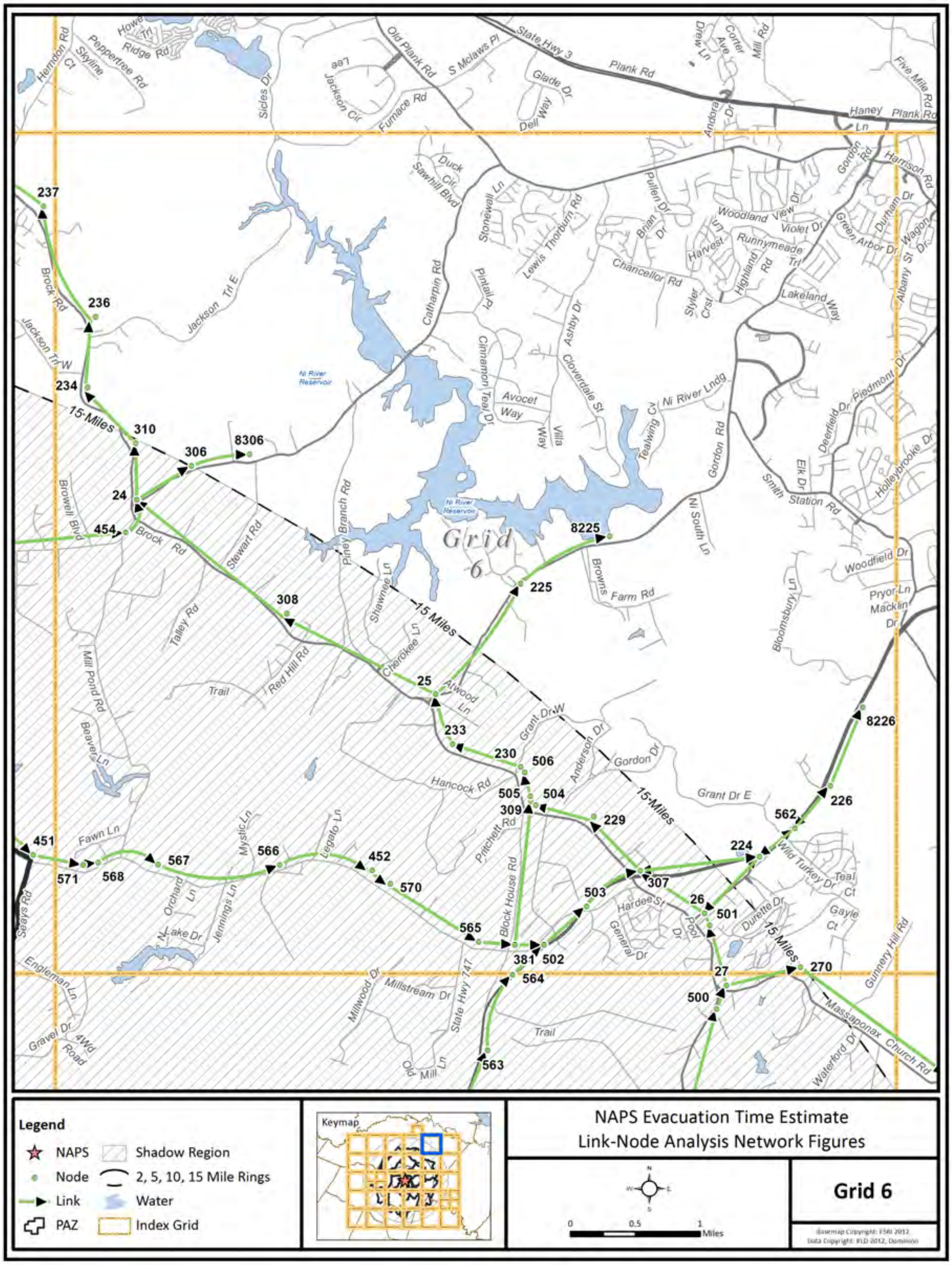


Figure K-7. Link-Node Analysis Network – Grid 6

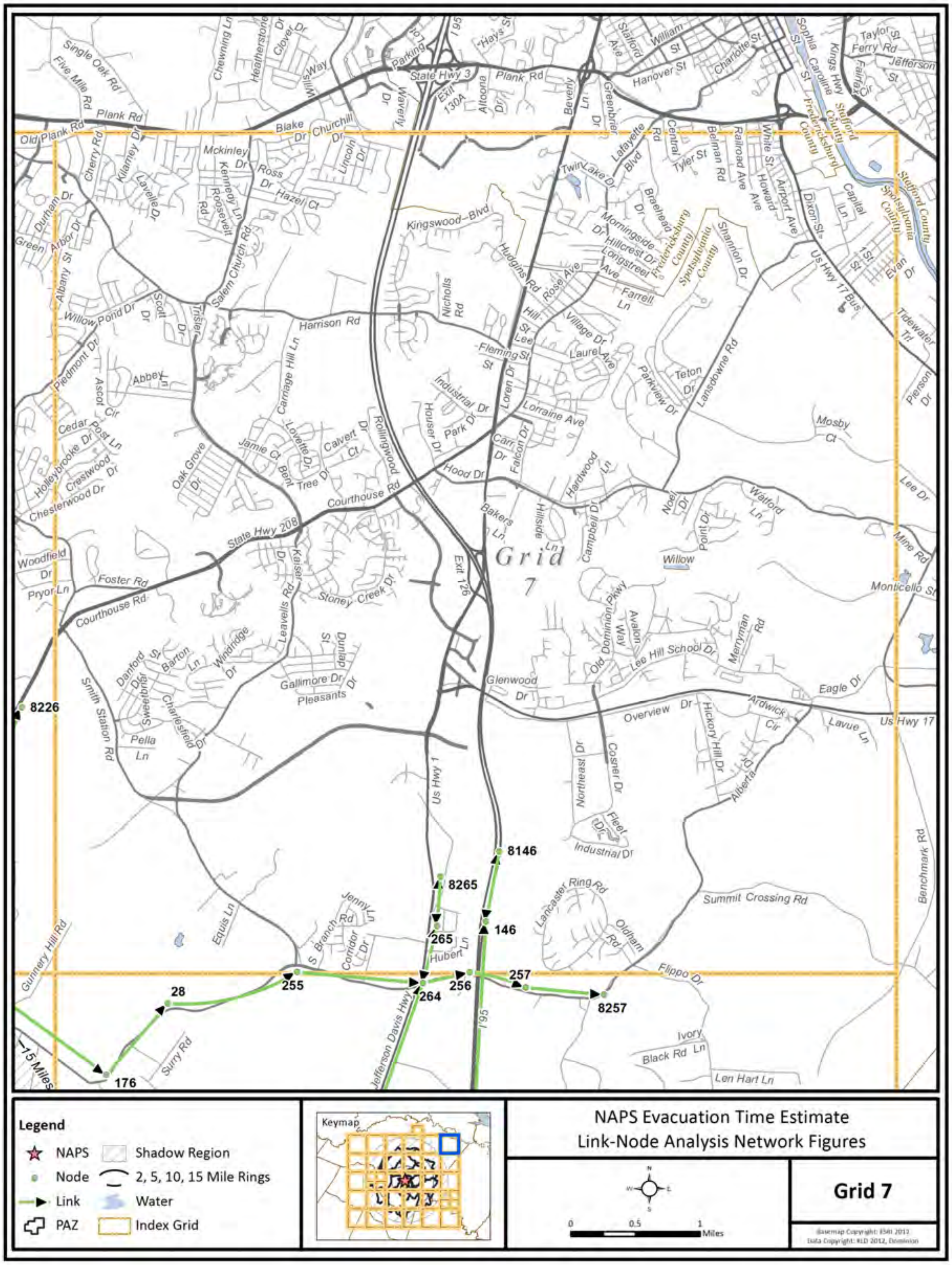


Figure K-8. Link-Node Analysis Network – Grid 7

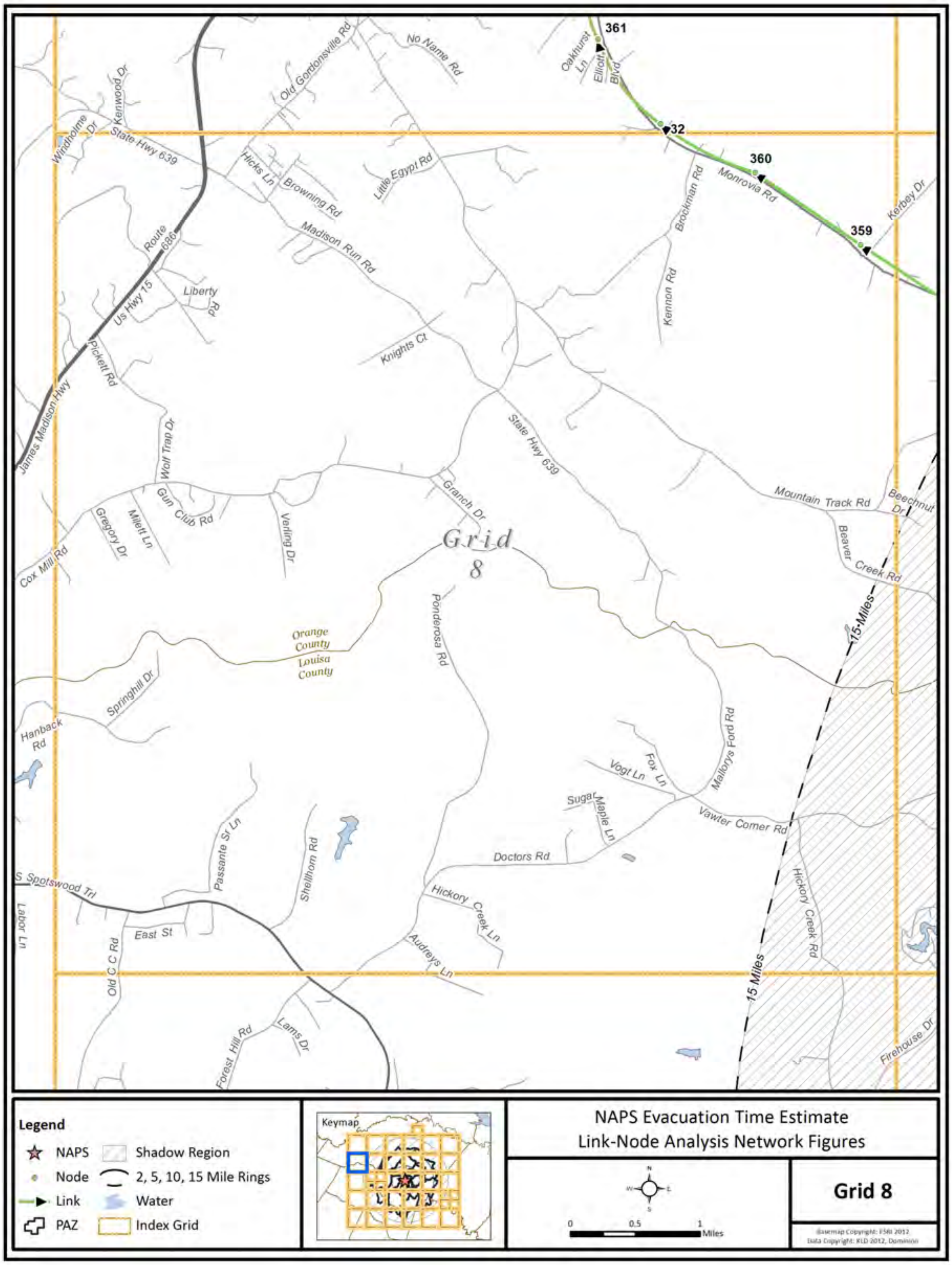


Figure K-9. Link-Node Analysis Network – Grid 8

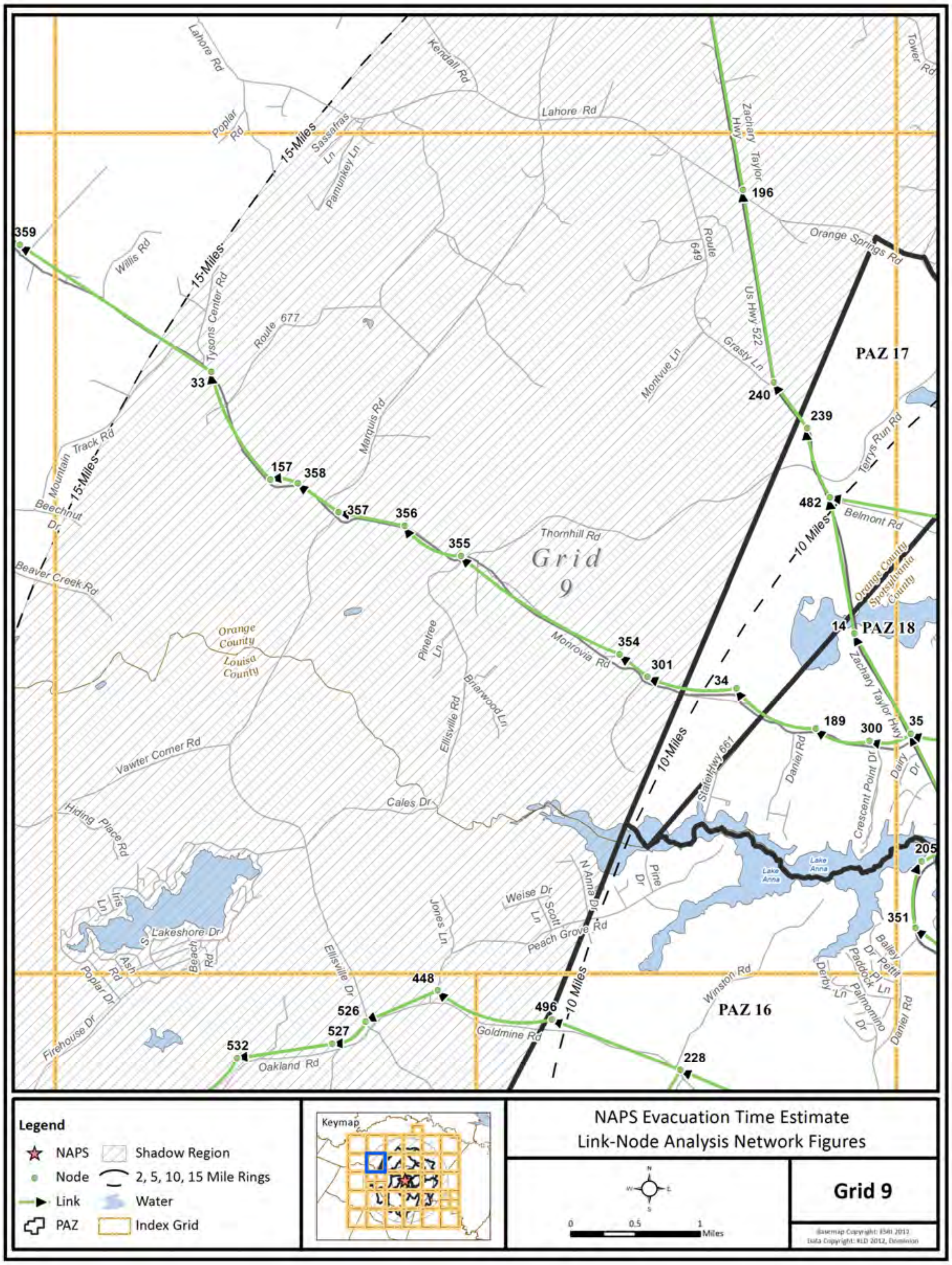


Figure K-10. Link-Node Analysis Network – Grid 9

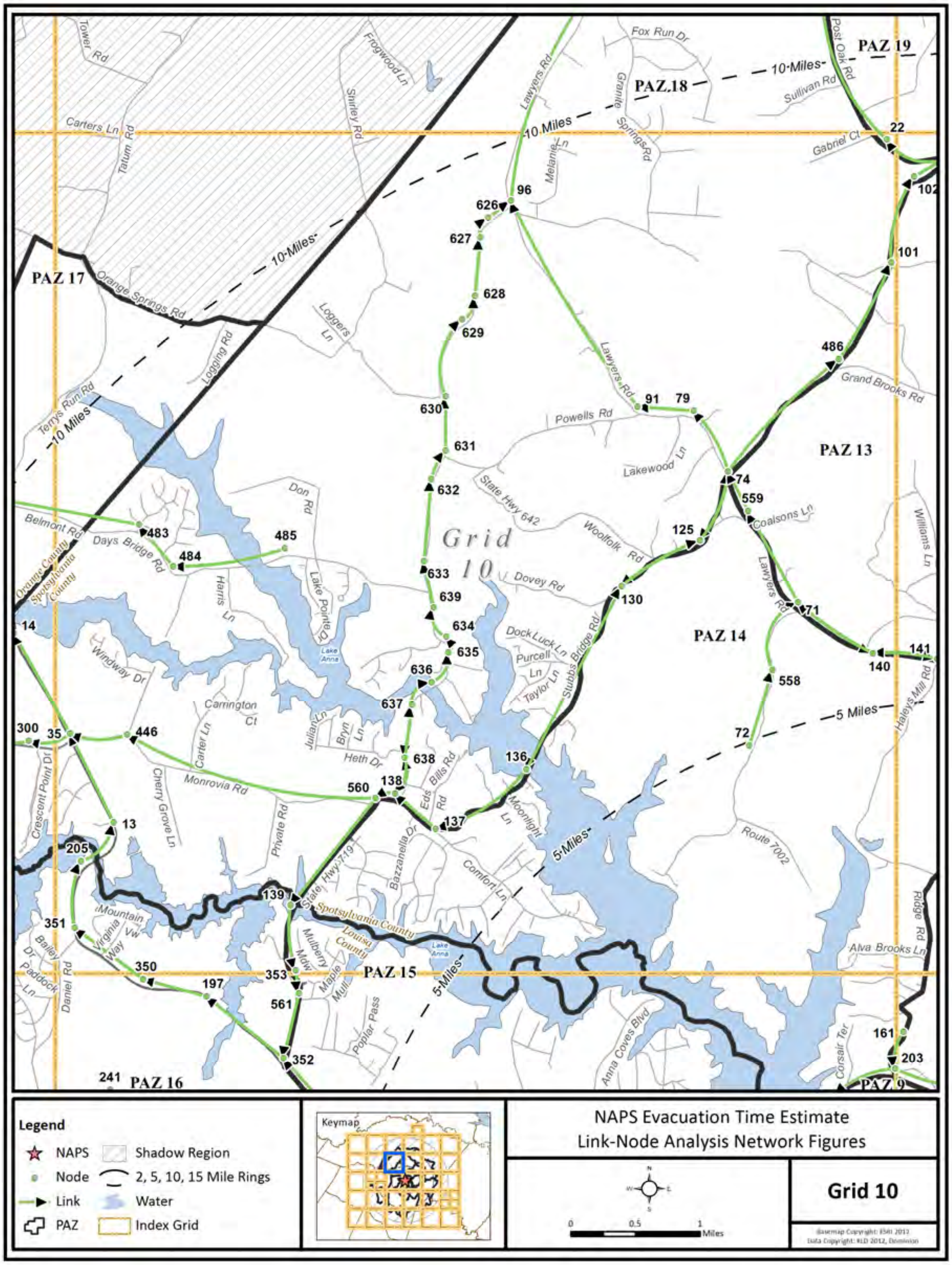


Figure K-11. Link-Node Analysis Network – Grid 10

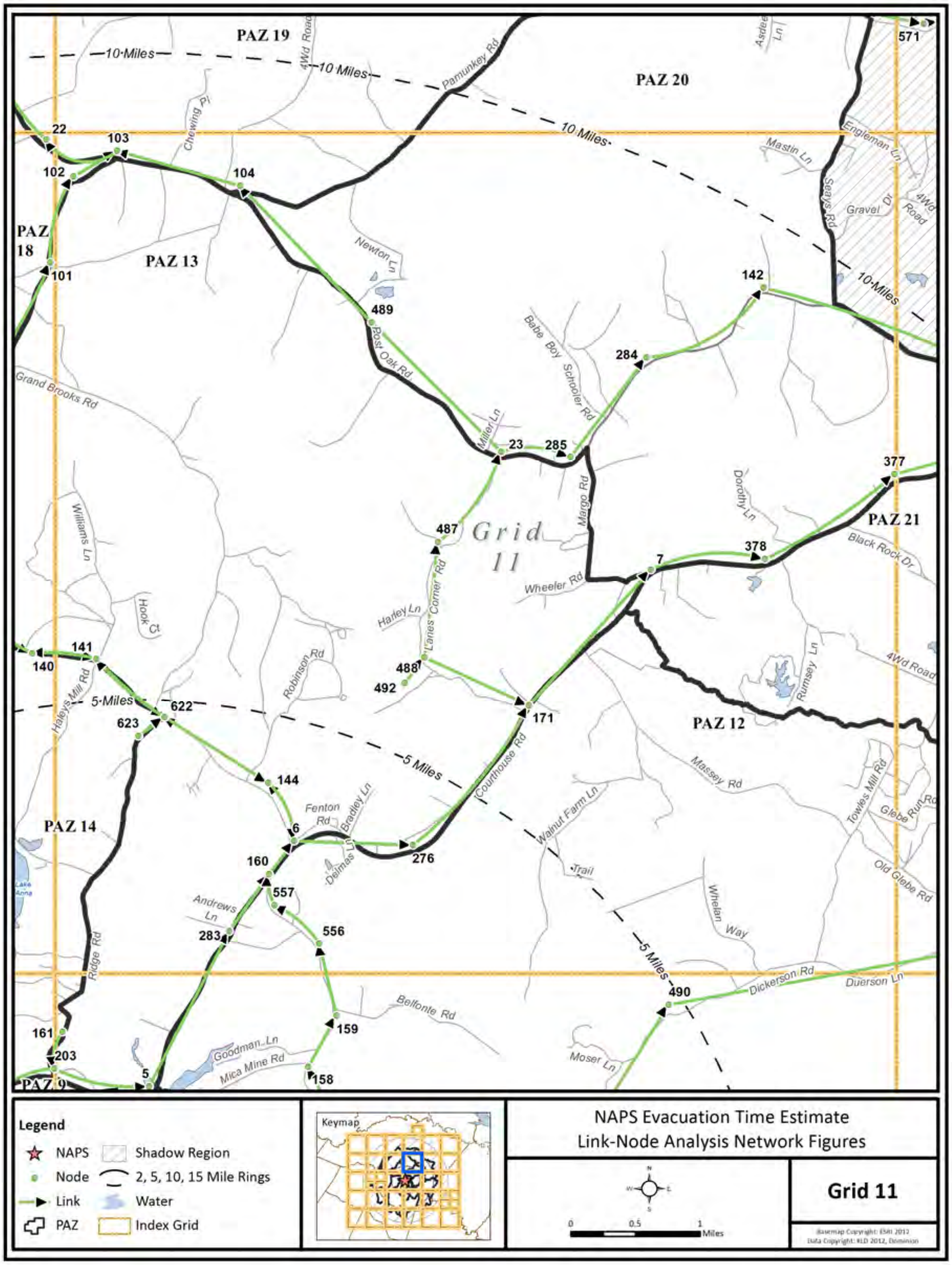


Figure K-12. Link-Node Analysis Network – Grid 11

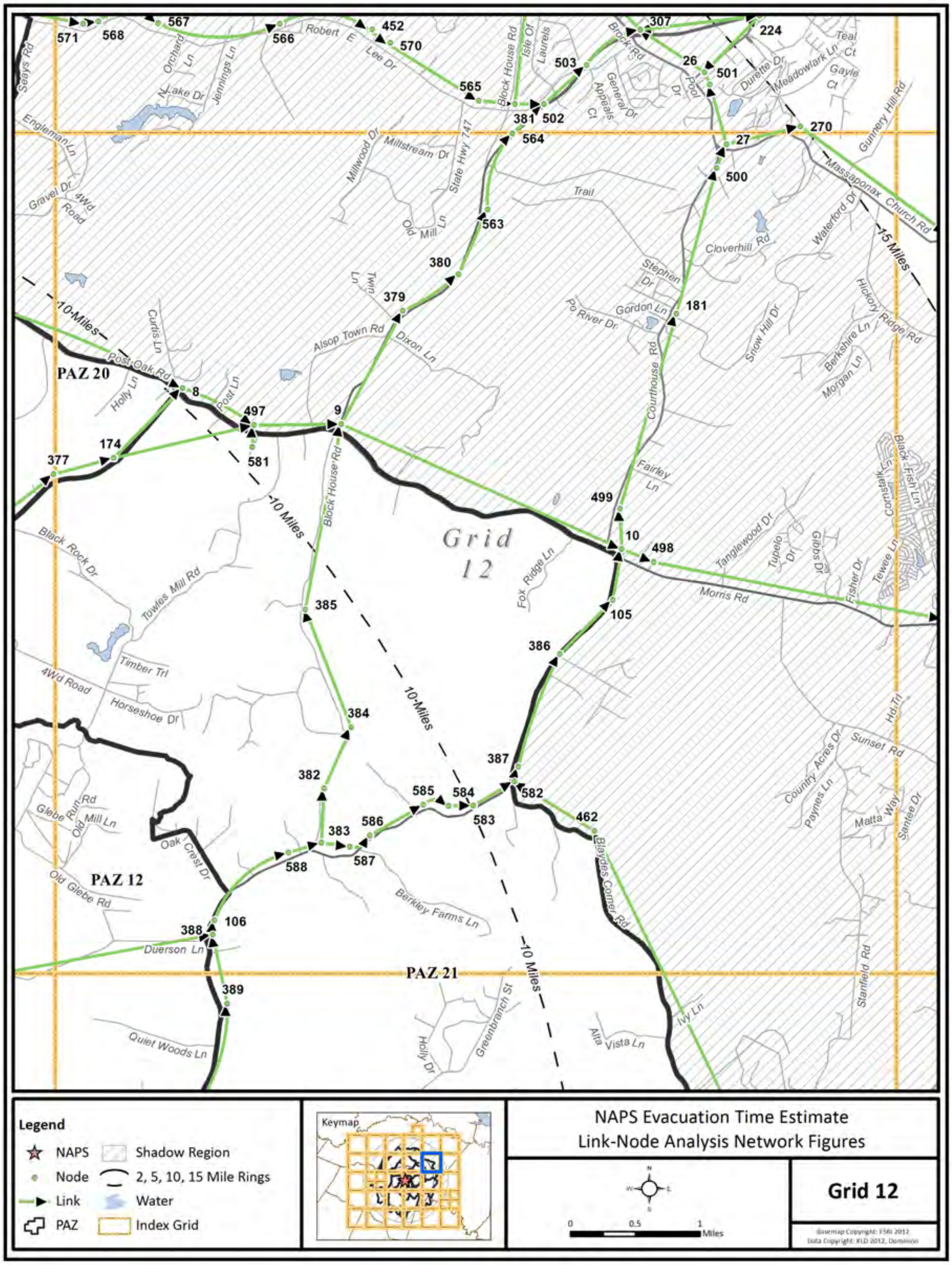
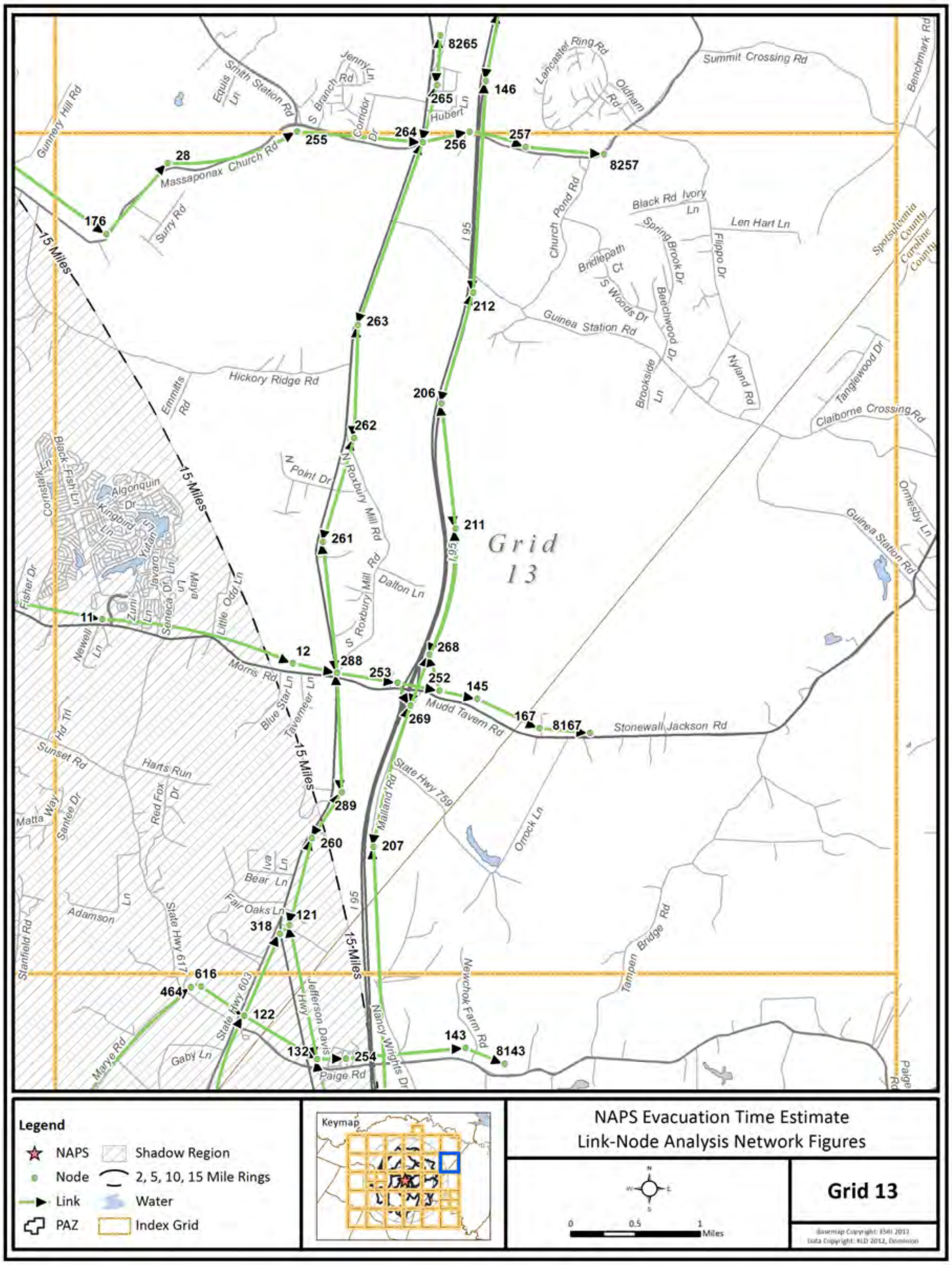


Figure K-13. Link-Node Analysis Network – Grid 12


Grid 13
Legend
NAPS
Node
Link
PAZ
Shadow Region
2, 5, 10, 15 Mile Rings
Water
Index Grid
Keymap
NAPS Evacuation Time Estimate
Link-Node Analysis Network Figures
Grid 13
Miles
15 Miles
I 95
Massaponax Church Rd
Guinea Station Rd
Hickory Ridge Rd
Morris Rd
Mudd Tavern Rd
Stonewall Jackson Rd
Summit Crossing Rd
Claiborne Crossing Rd
State Hwy 759
Jefferson Davis Hwy
Paige Rd
8265
146
265
264
256
257
8257
255
28
176
212
263
206
262
261
211
11
12
288
253
252
268
145
269
167
8167
289
260
207
121
318
616
464
122
132
254
143
8143

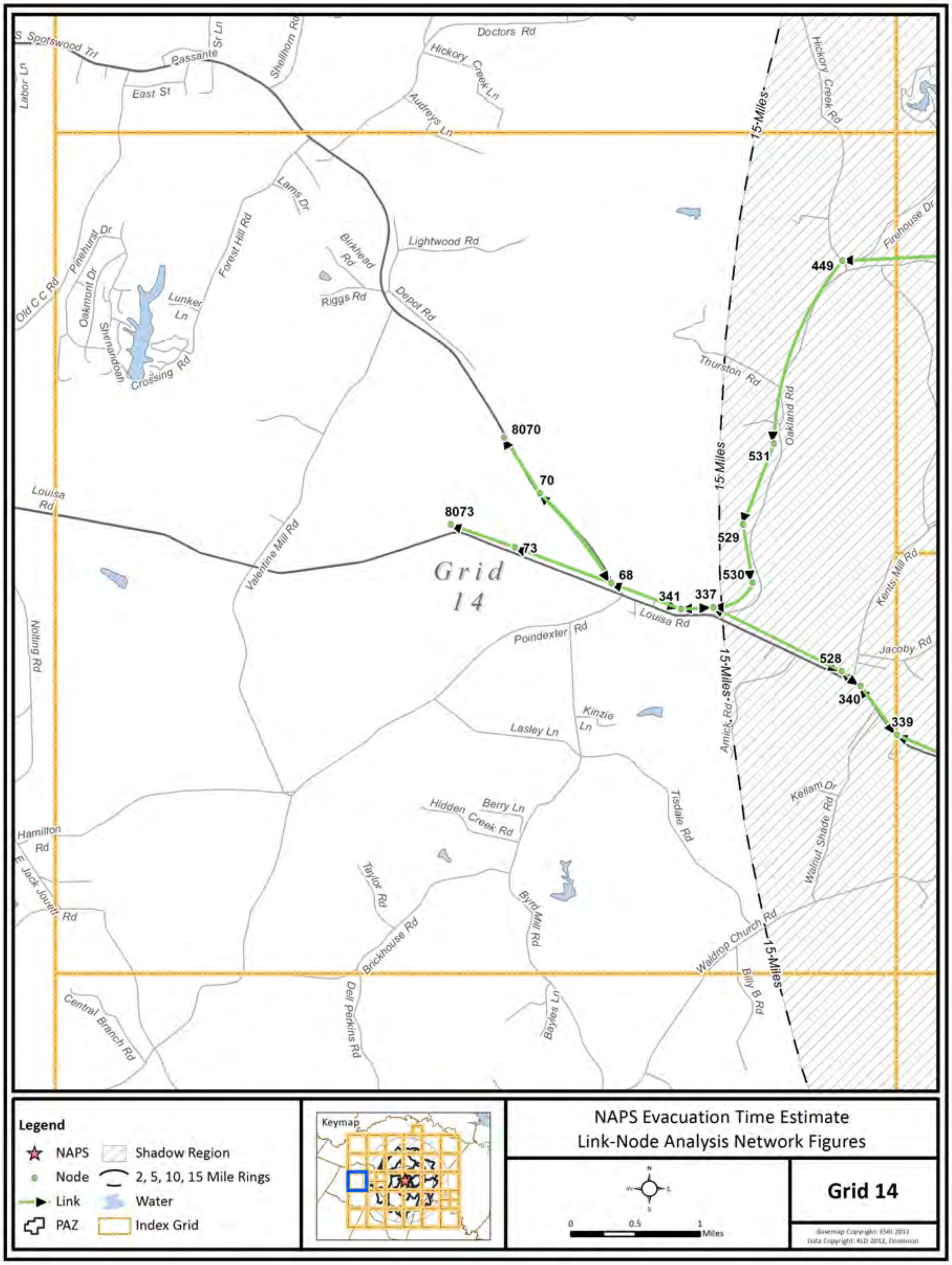


Figure K-15. Link-Node Analysis Network – Grid 14

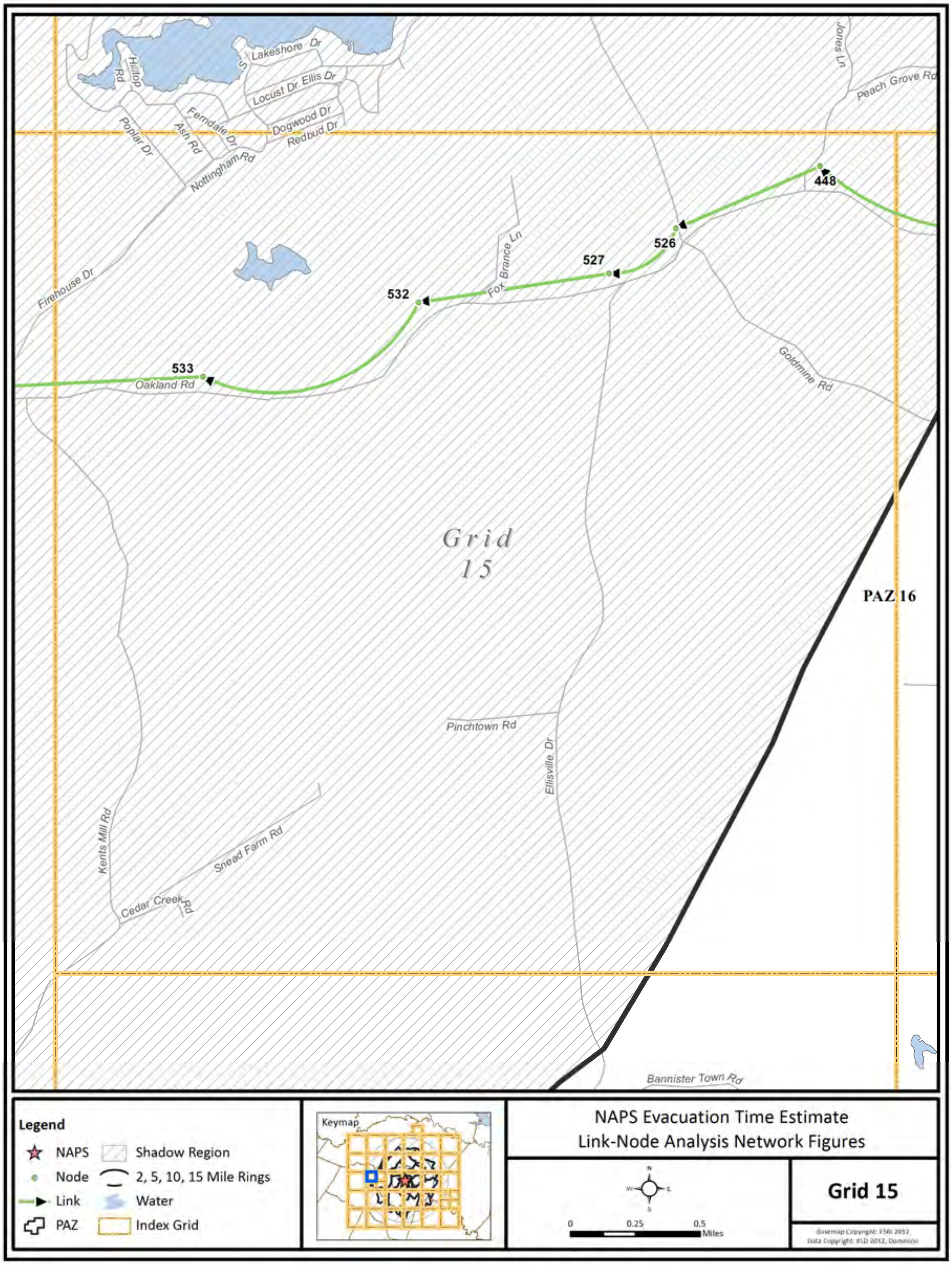


Figure K-16. Link-Node Analysis Network – Grid 15

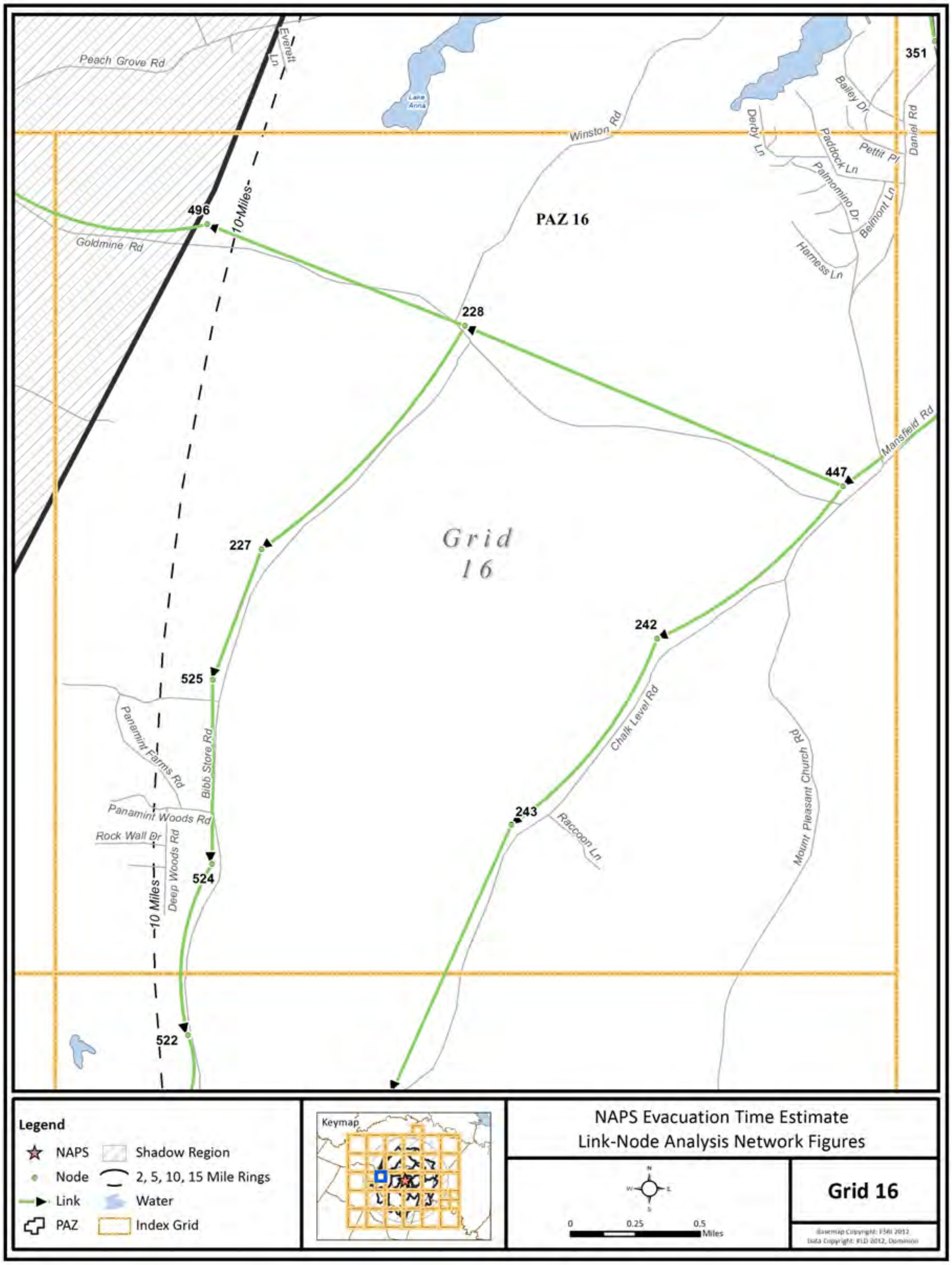


Figure K-17. Link-Node Analysis Network – Grid 16

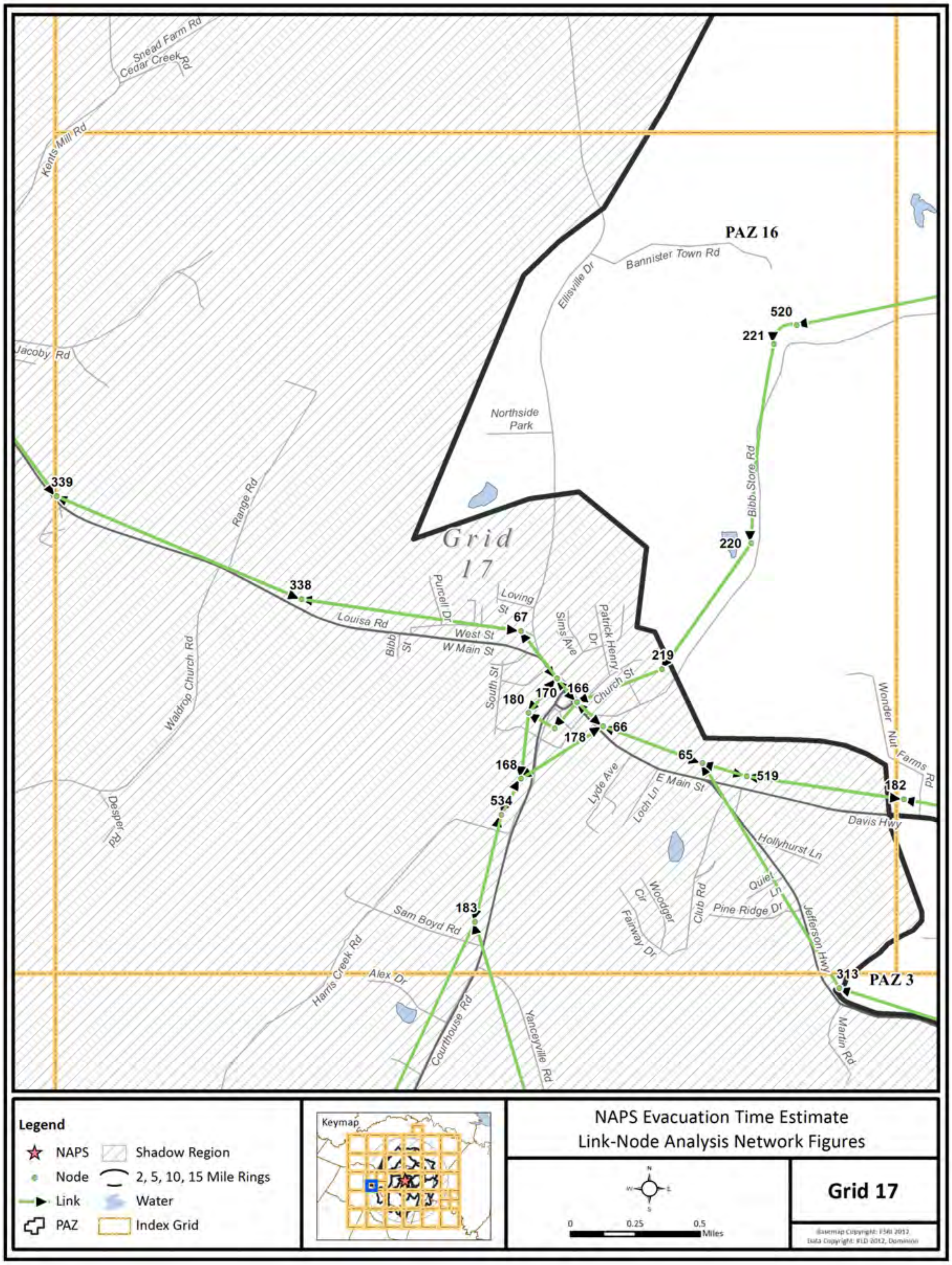


Figure K-18. Link-Node Analysis Network – Grid 17

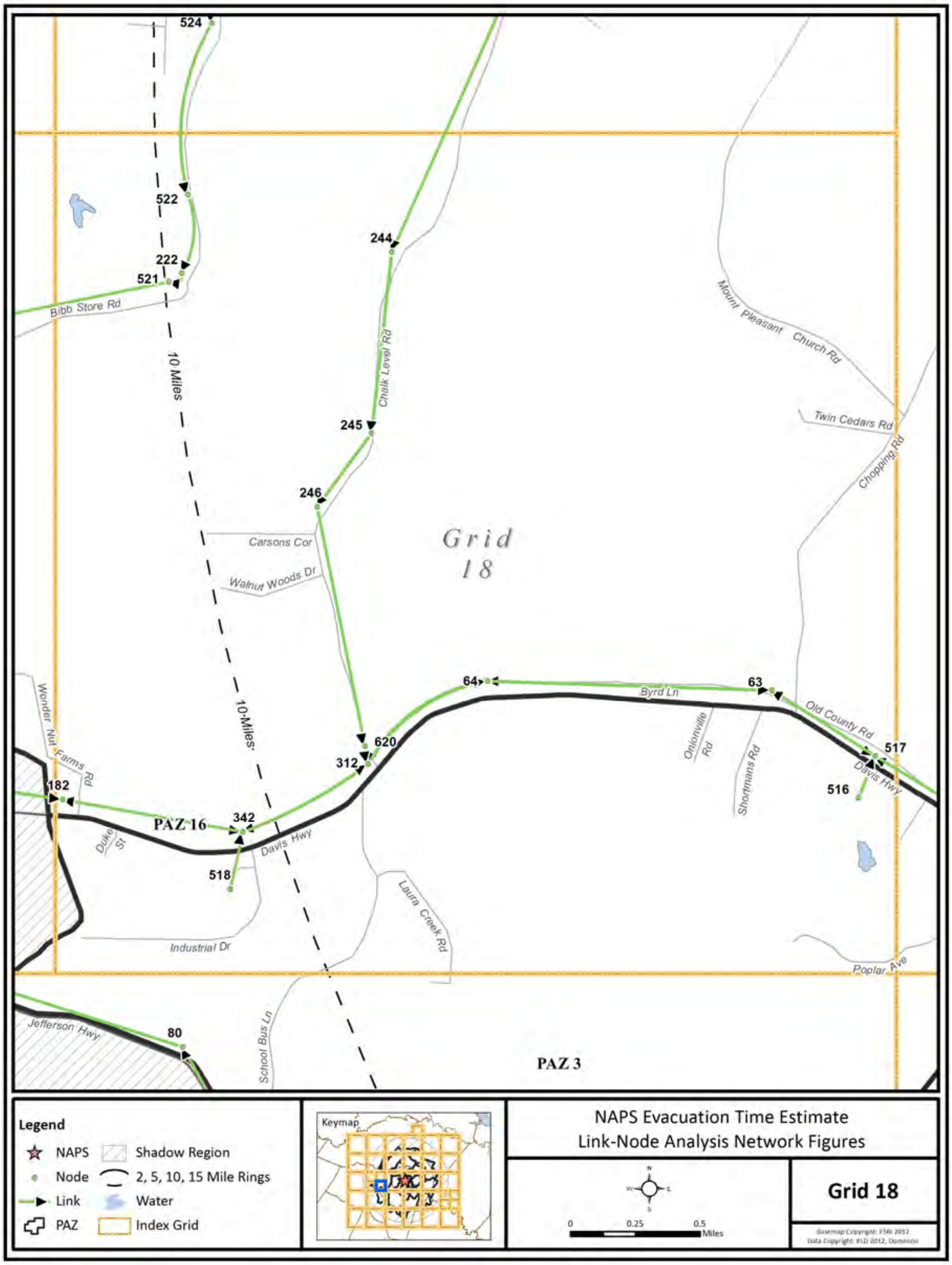


Figure K-19. Link-Node Analysis Network – Grid 18

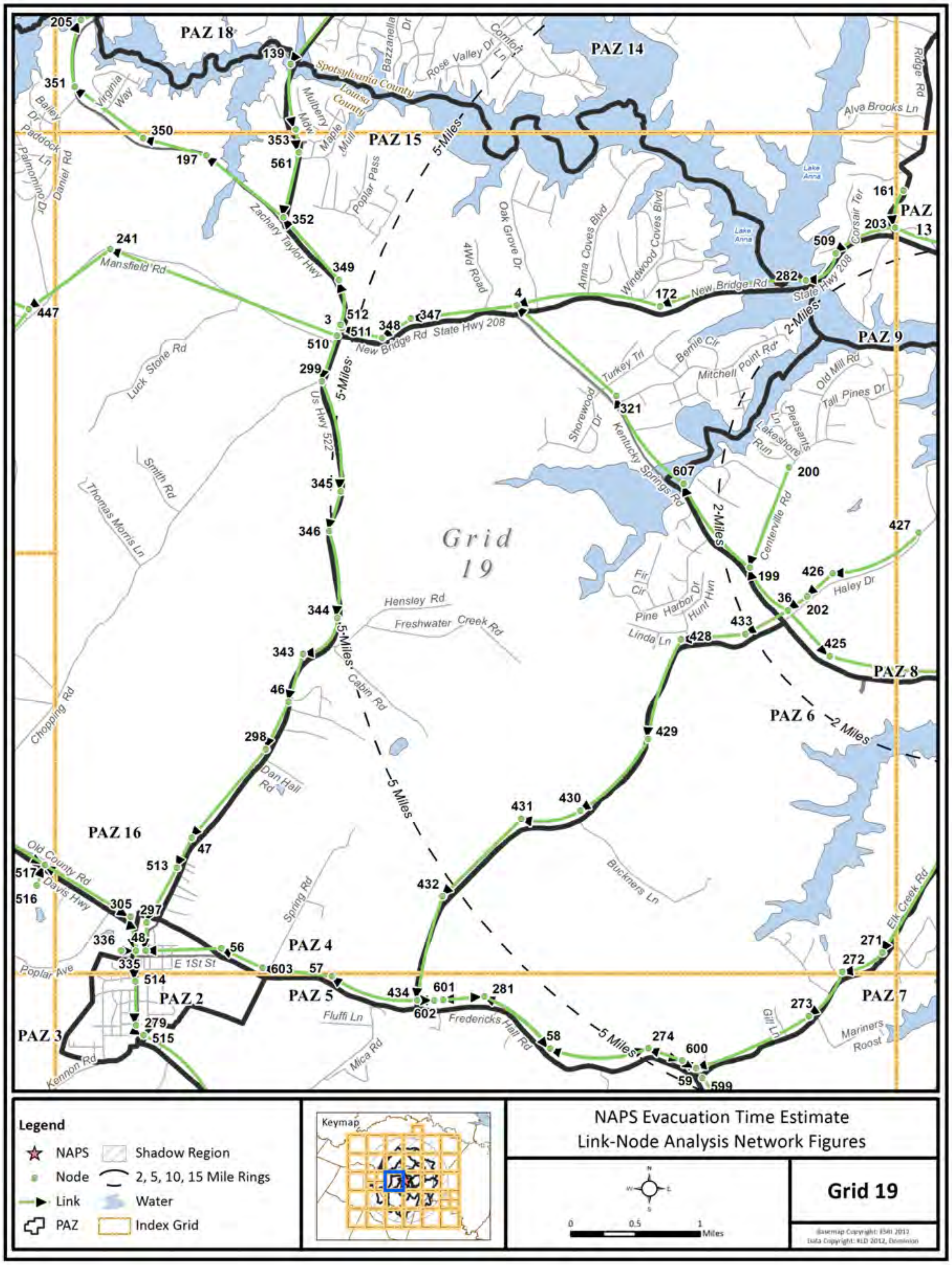


Figure K-20. Link-Node Analysis Network – Grid 19

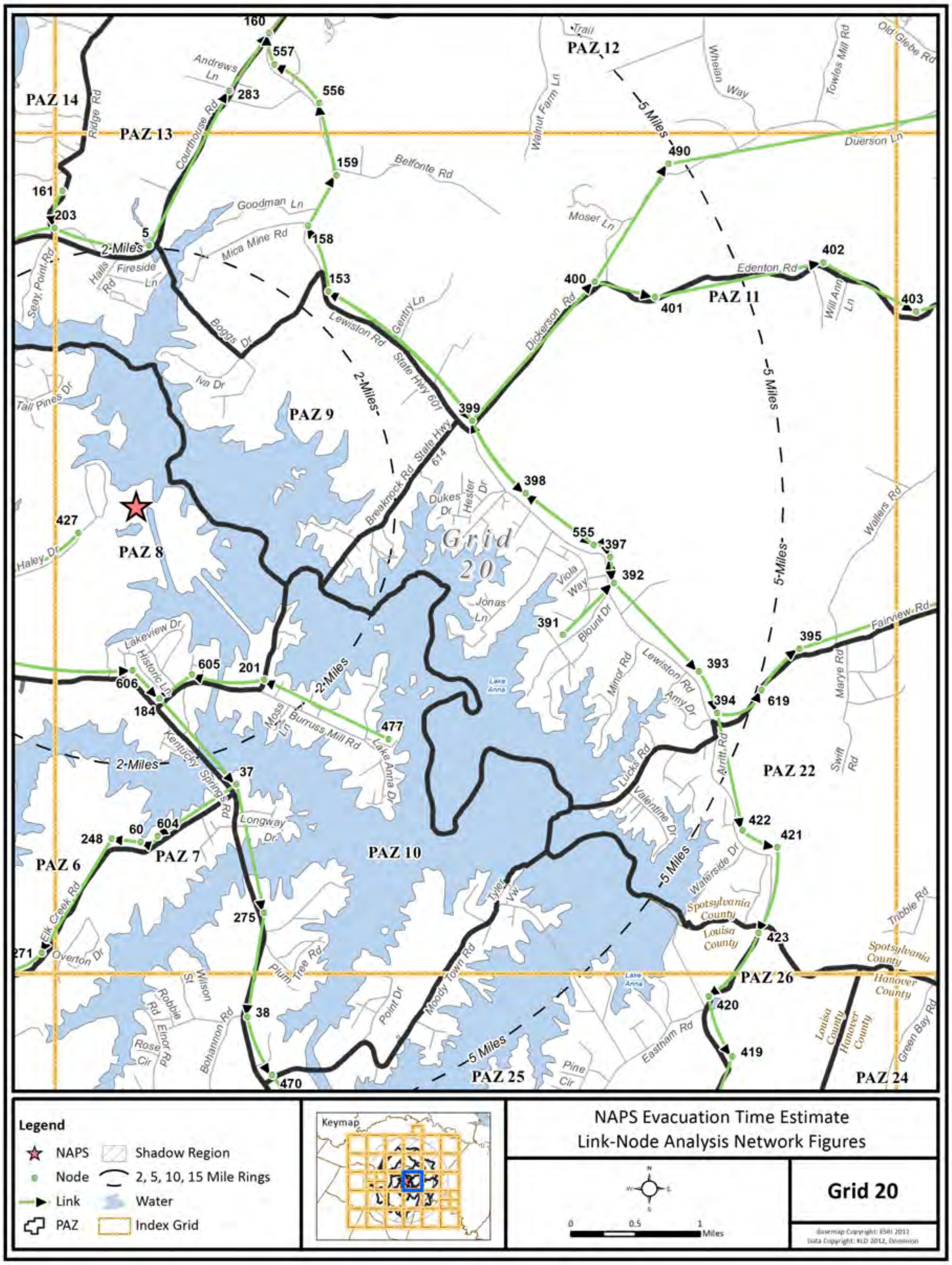


Figure K-21. Link-Node Analysis Network – Grid 20

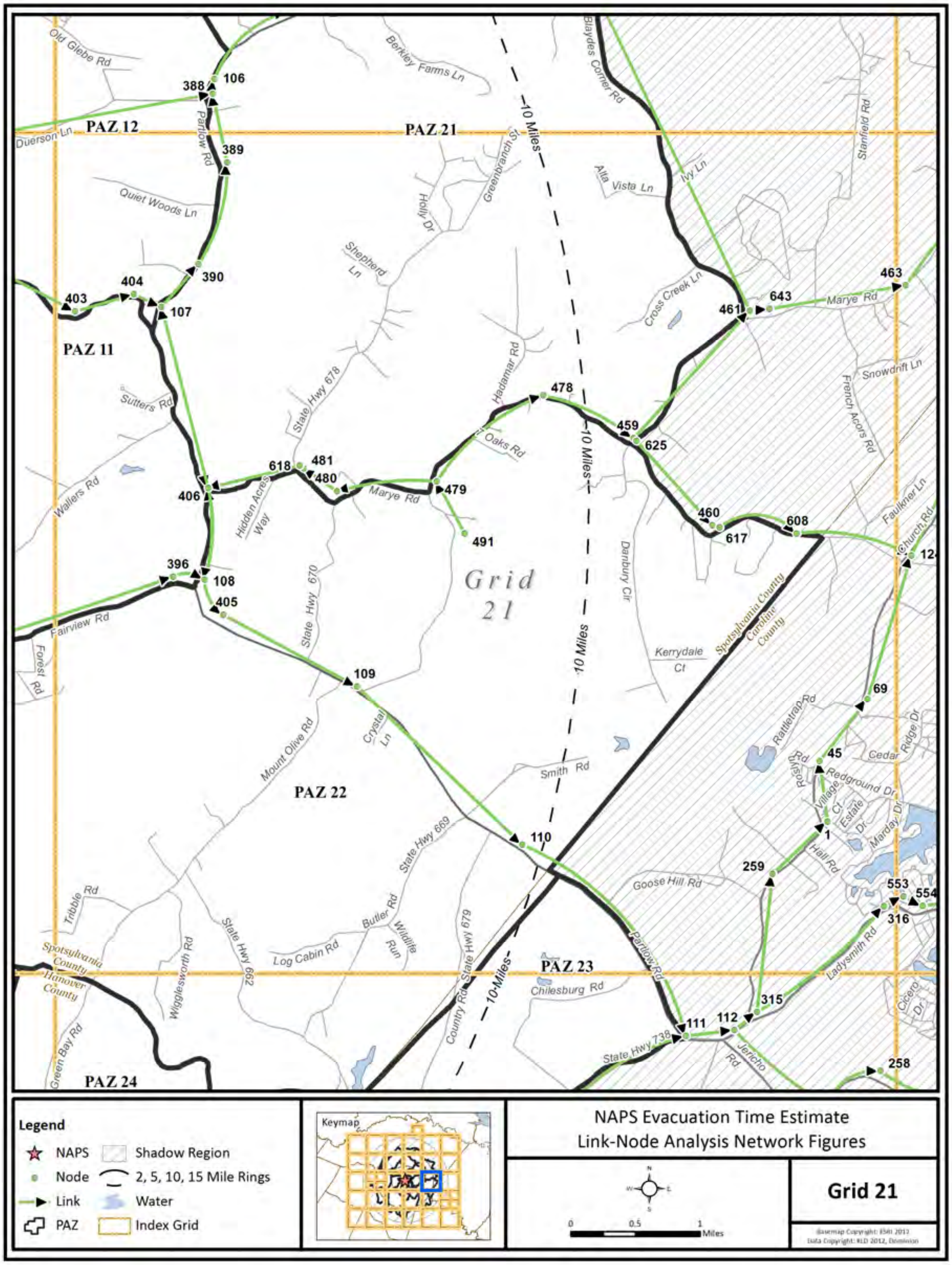


Figure K-22. Link-Node Analysis Network – Grid 21

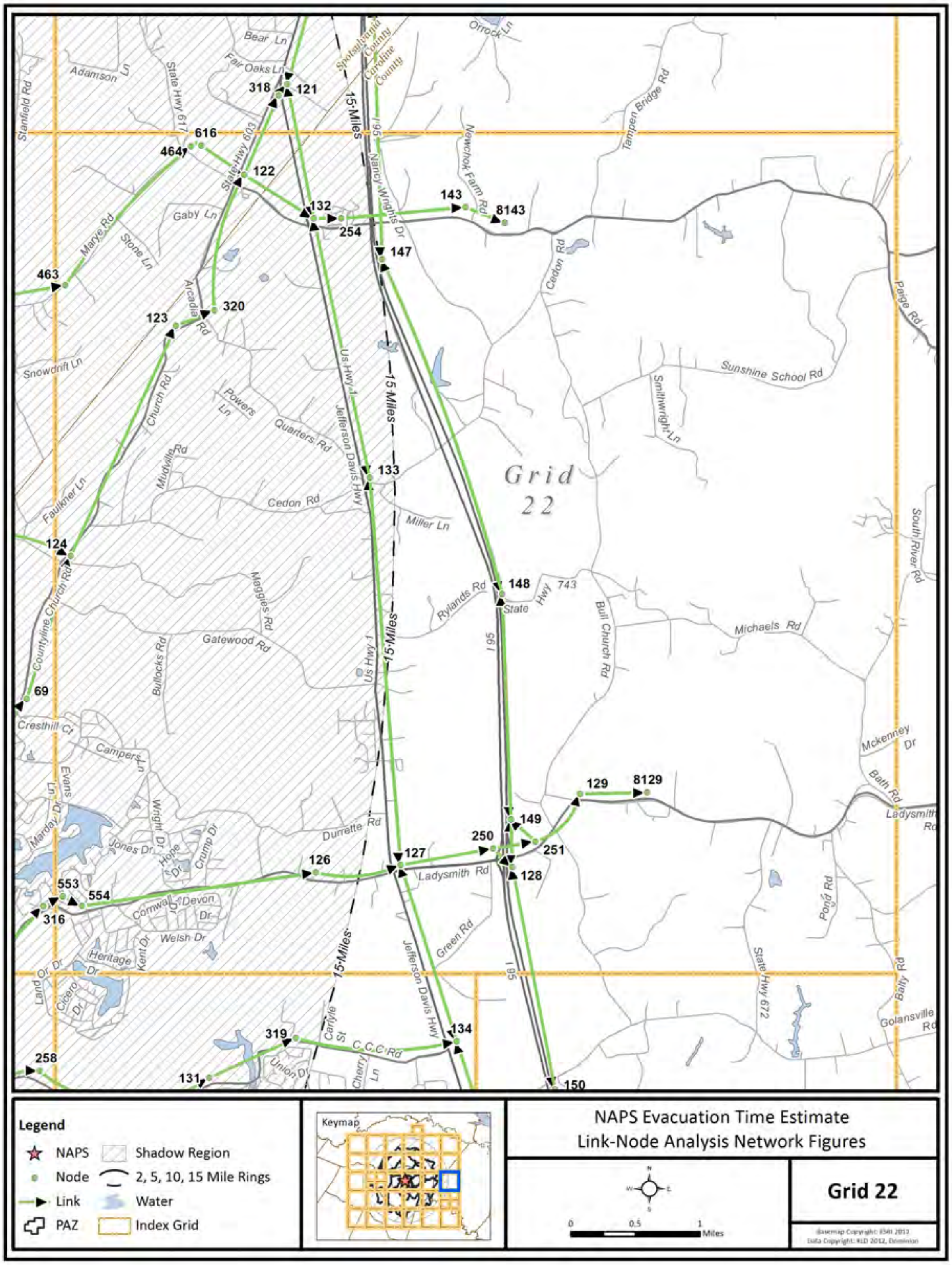


Figure K-23. Link-Node Analysis Network – Grid 22

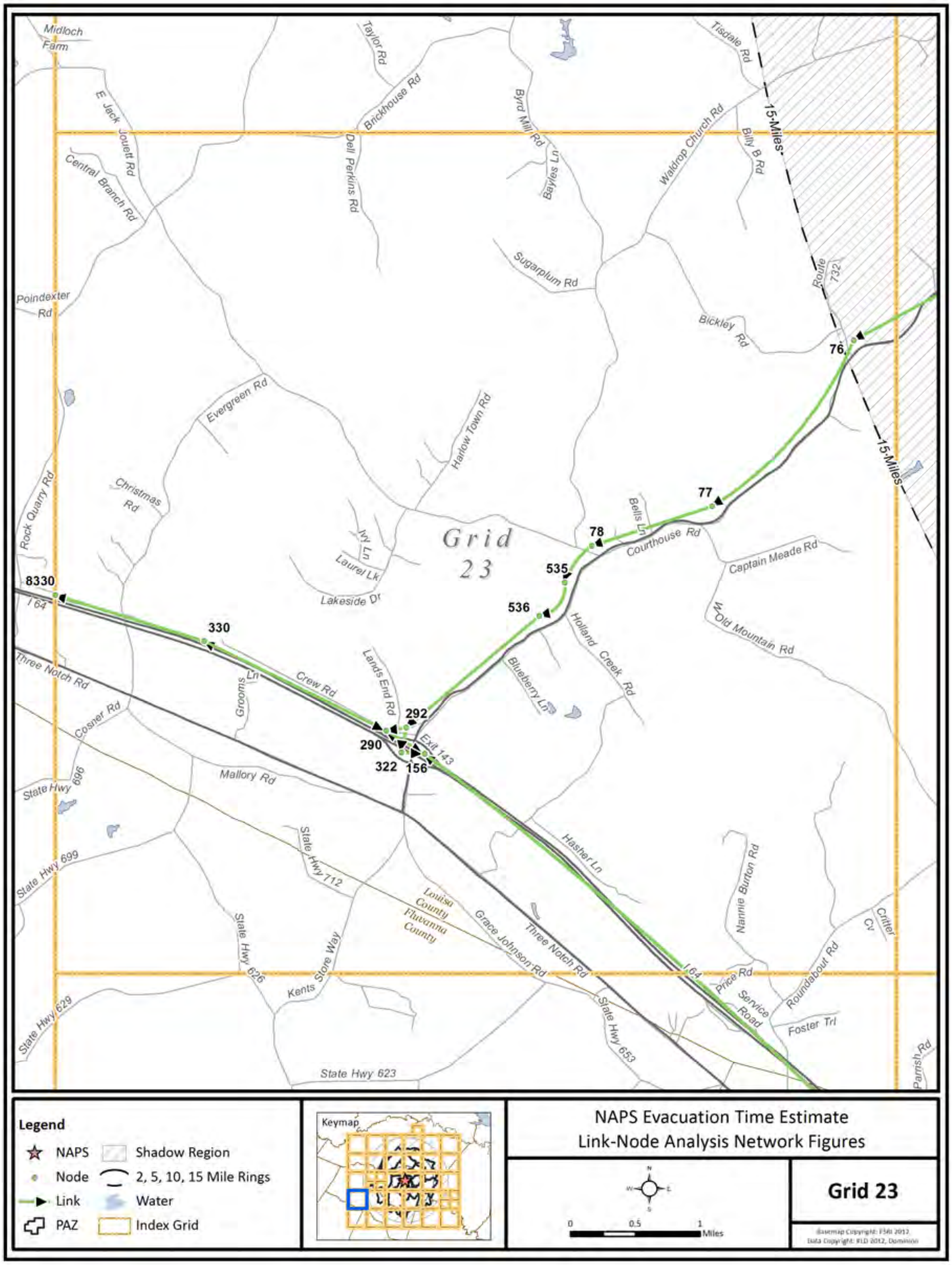


Figure K-24. Link-Node Analysis Network – Grid 23

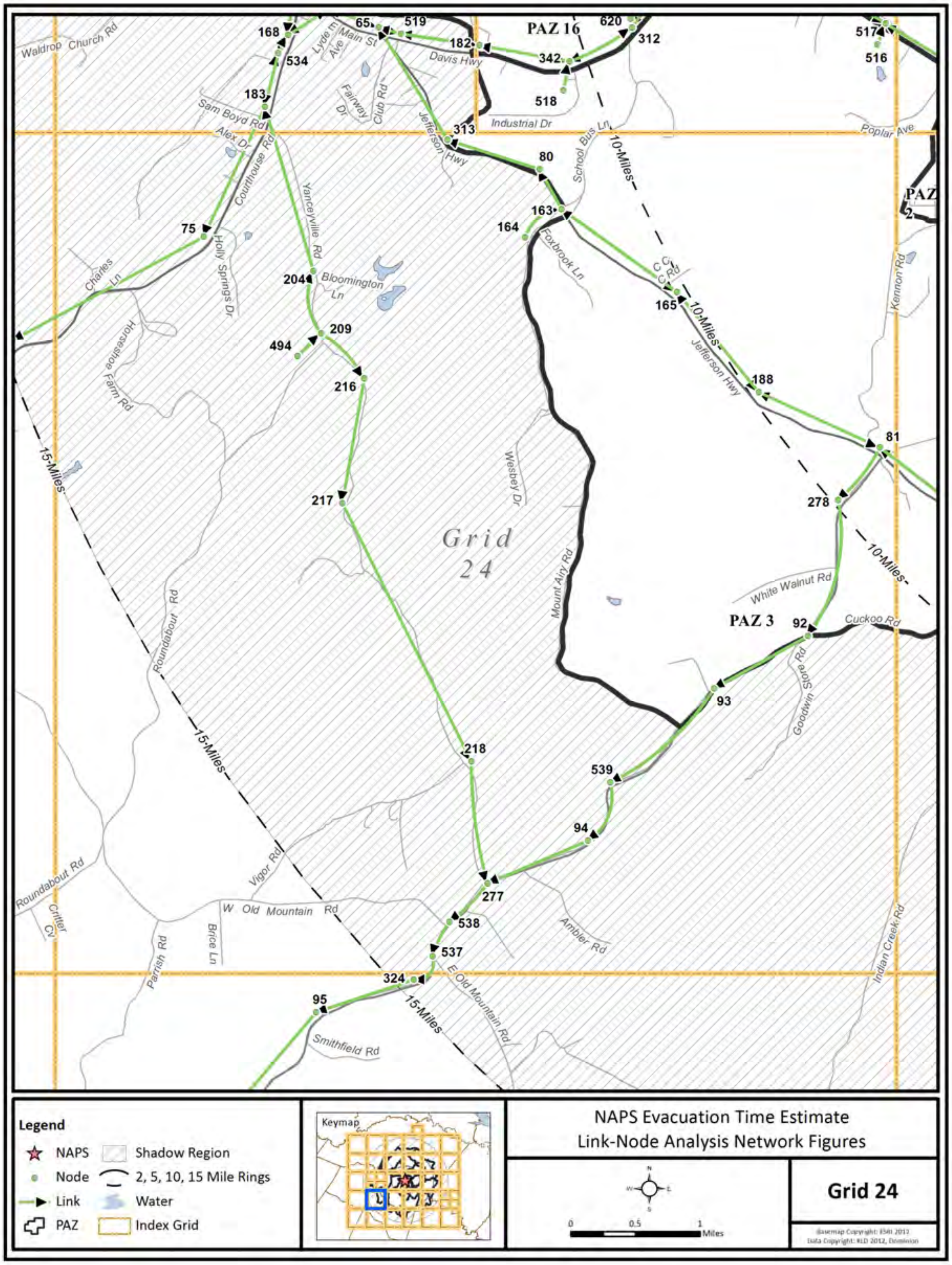


Figure K-25. Link-Node Analysis Network – Grid 24

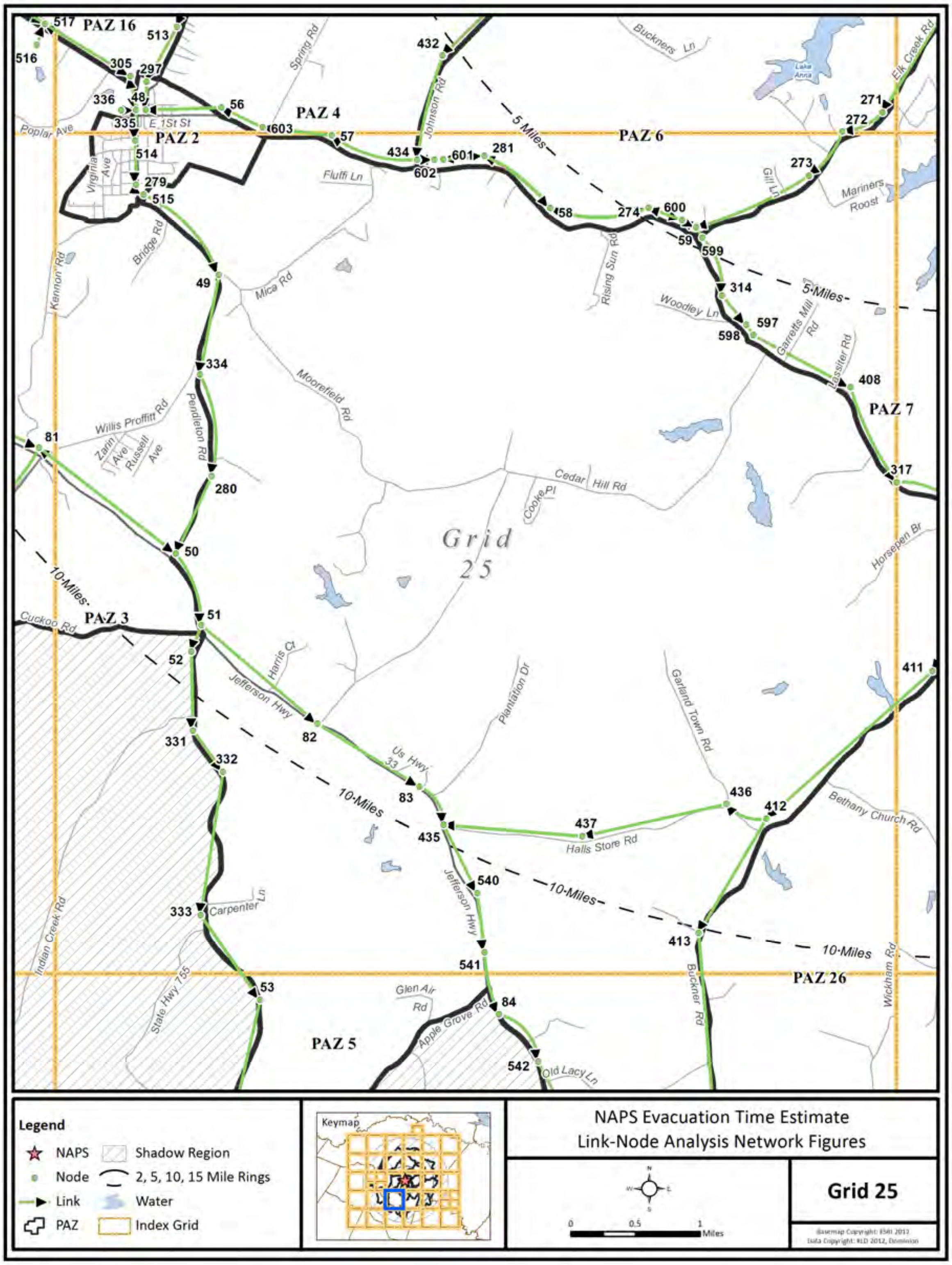


Figure K-26. Link-Node Analysis Network – Grid 25

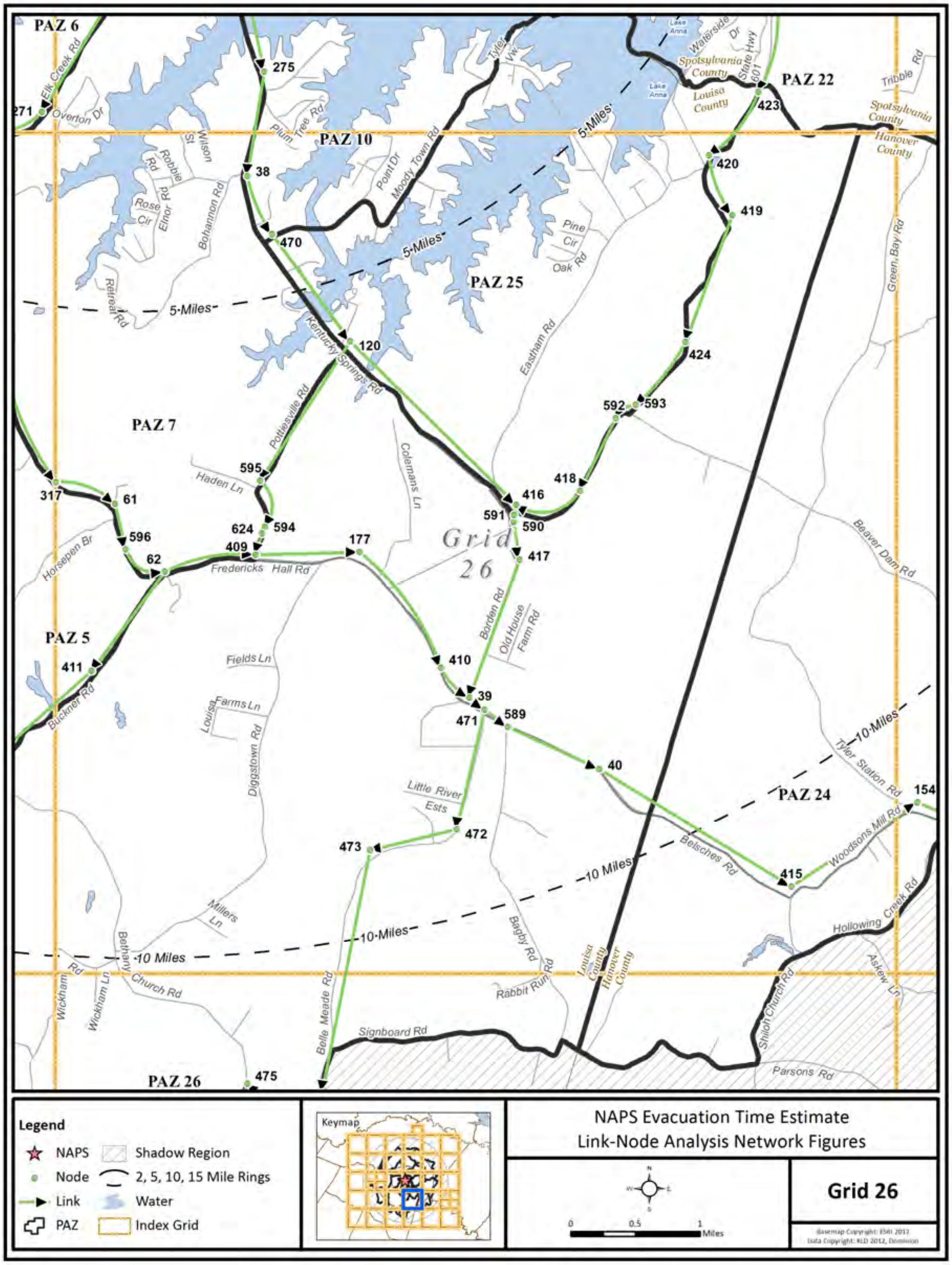


Figure K-27. Link-Node Analysis Network – Grid 26

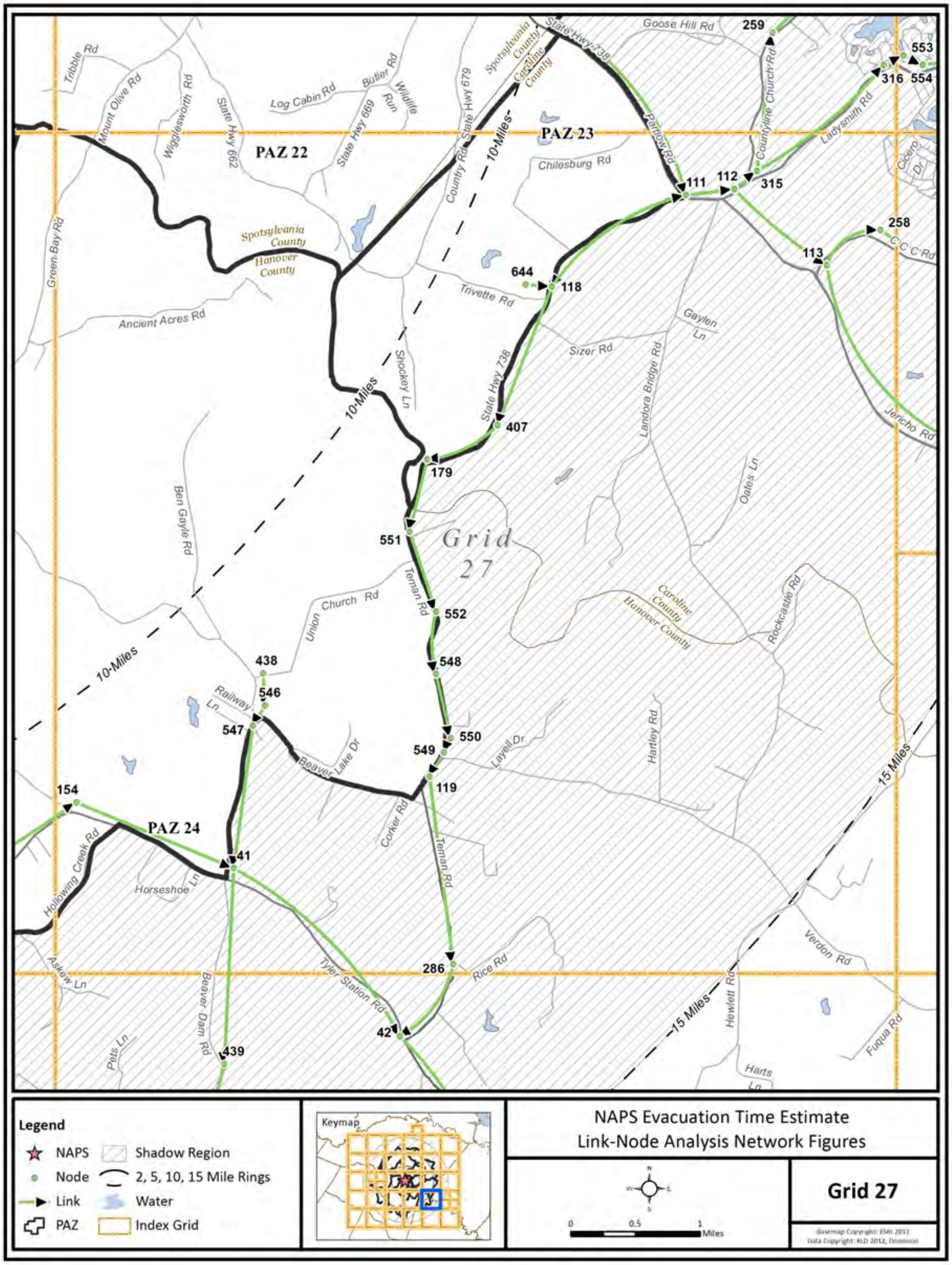


Figure K-28. Link-Node Analysis Network – Grid 27

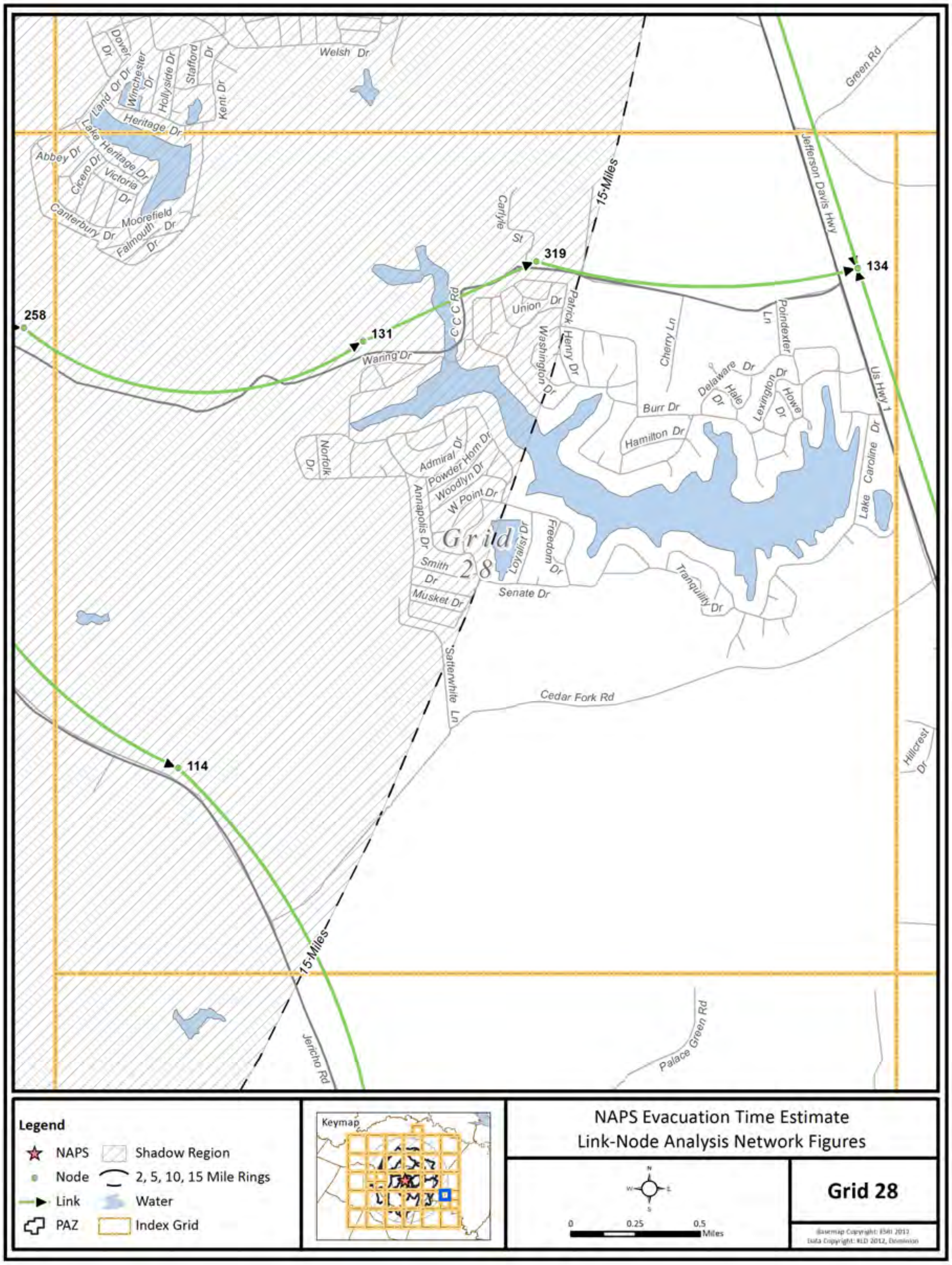


Figure K-29. Link-Node Analysis Network – Grid 28

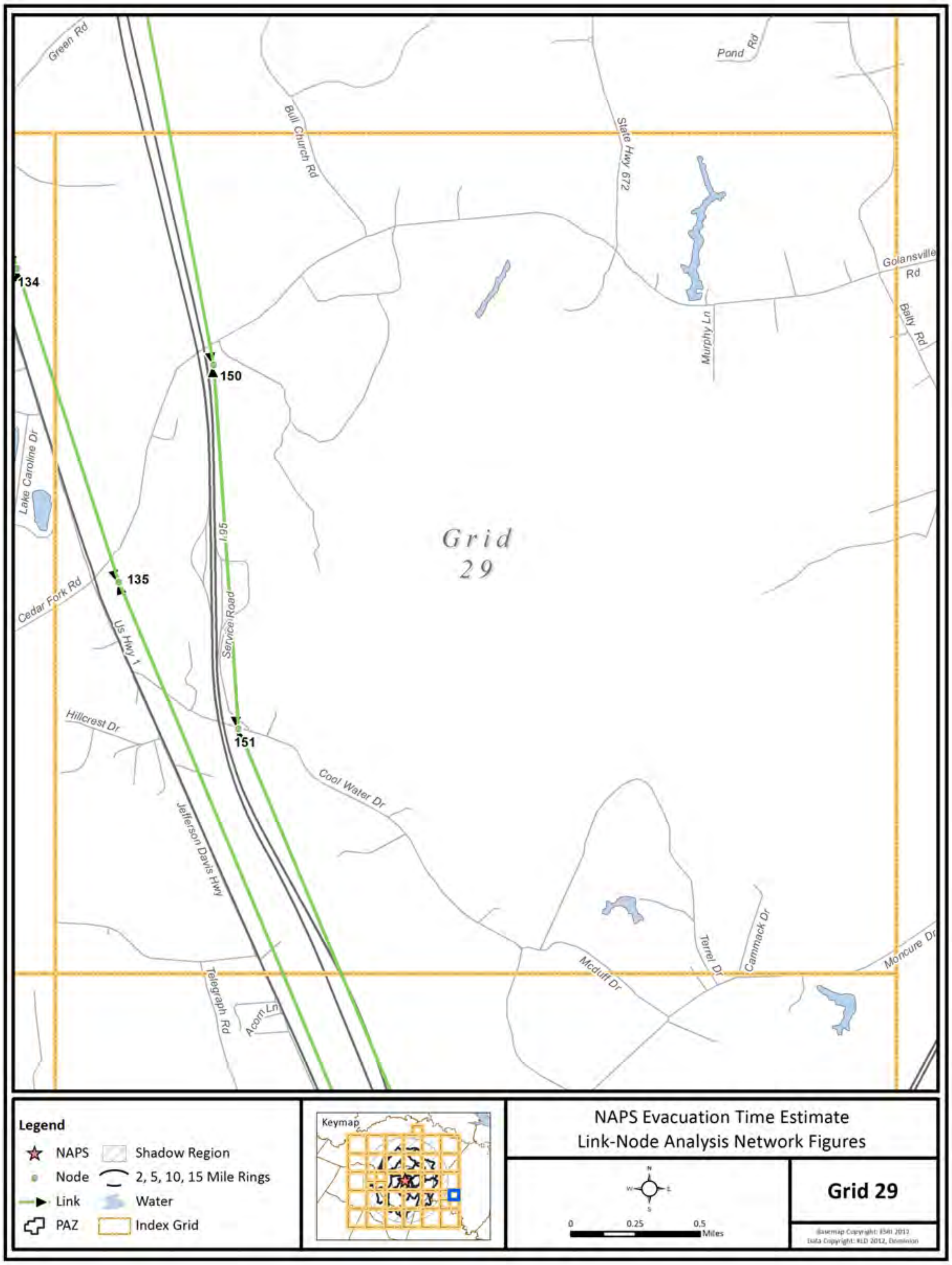


Figure K-30. Link-Node Analysis Network – Grid 29

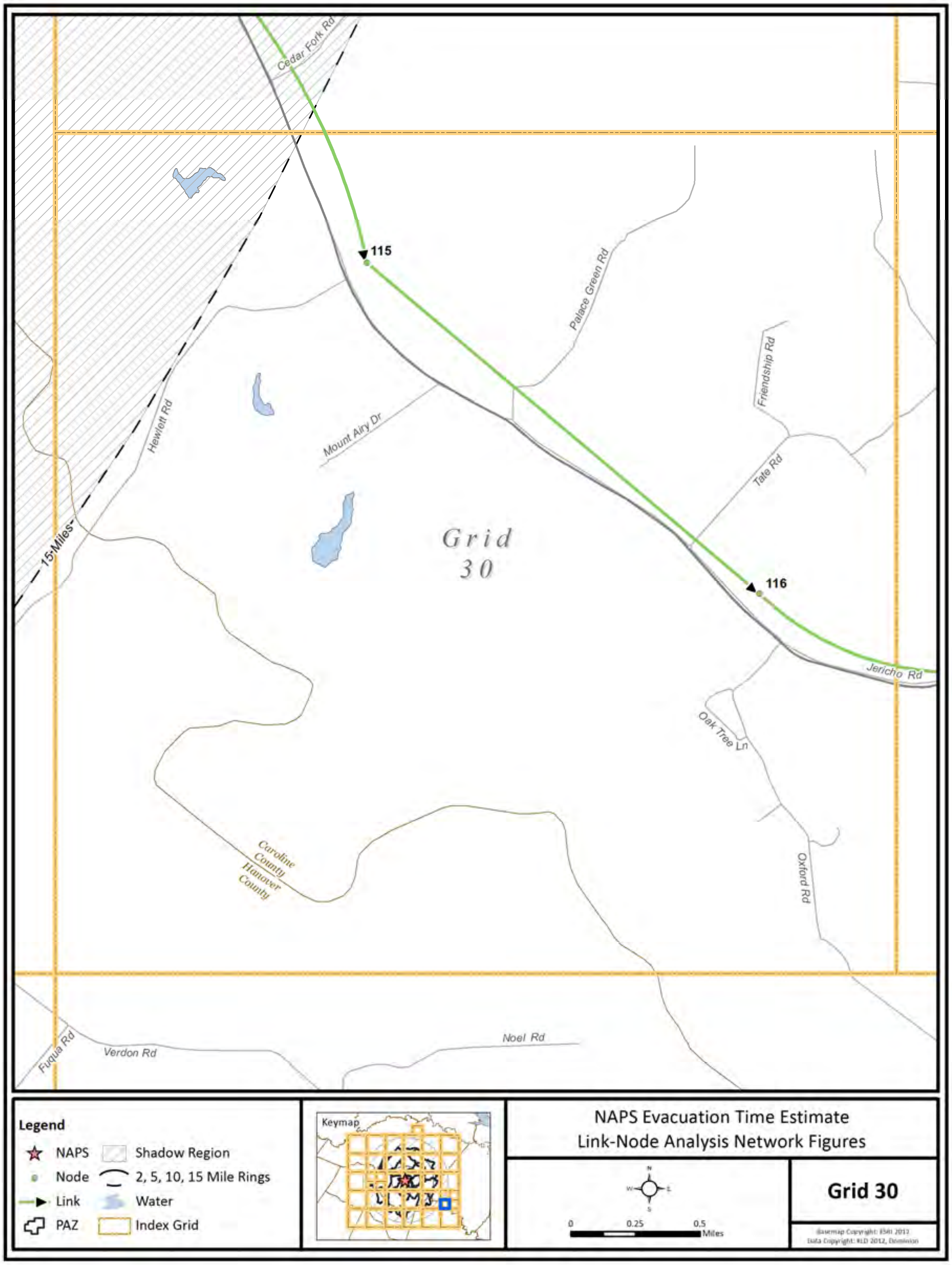


Figure K-31. Link-Node Analysis Network – Grid 30

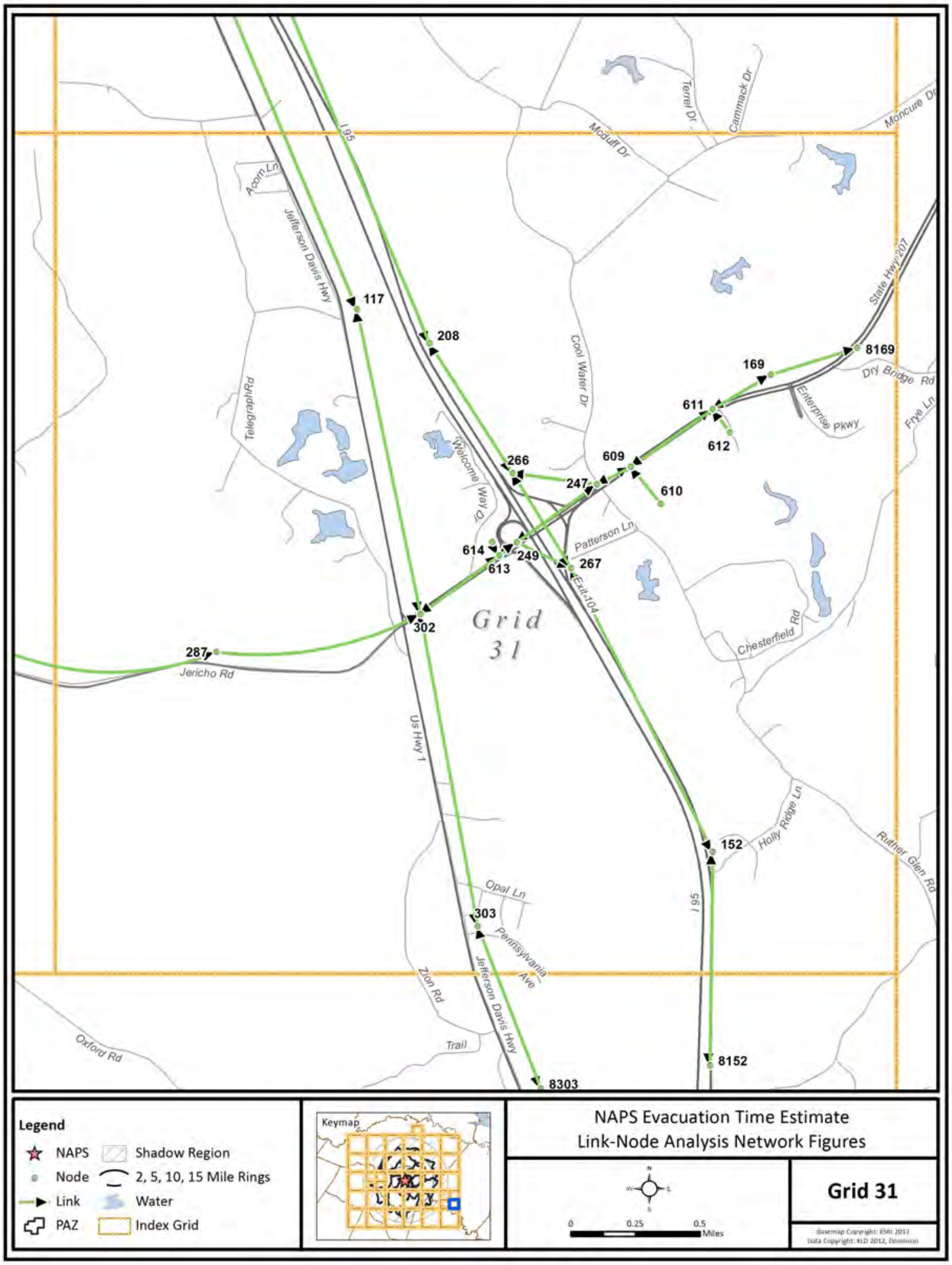


Figure K-32. Link-Node Analysis Network – Grid 31

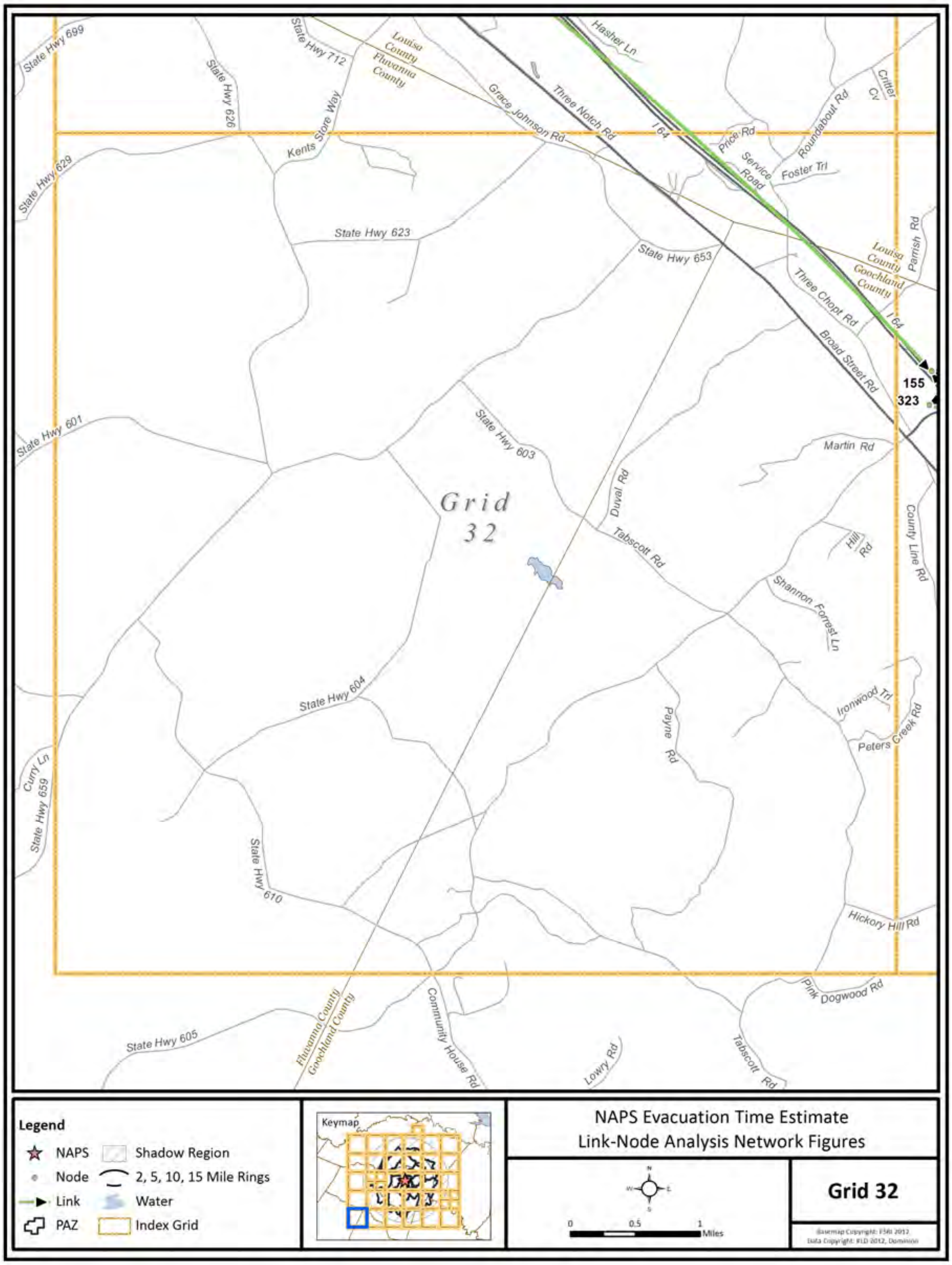


Figure K-33. Link-Node Analysis Network – Grid 32

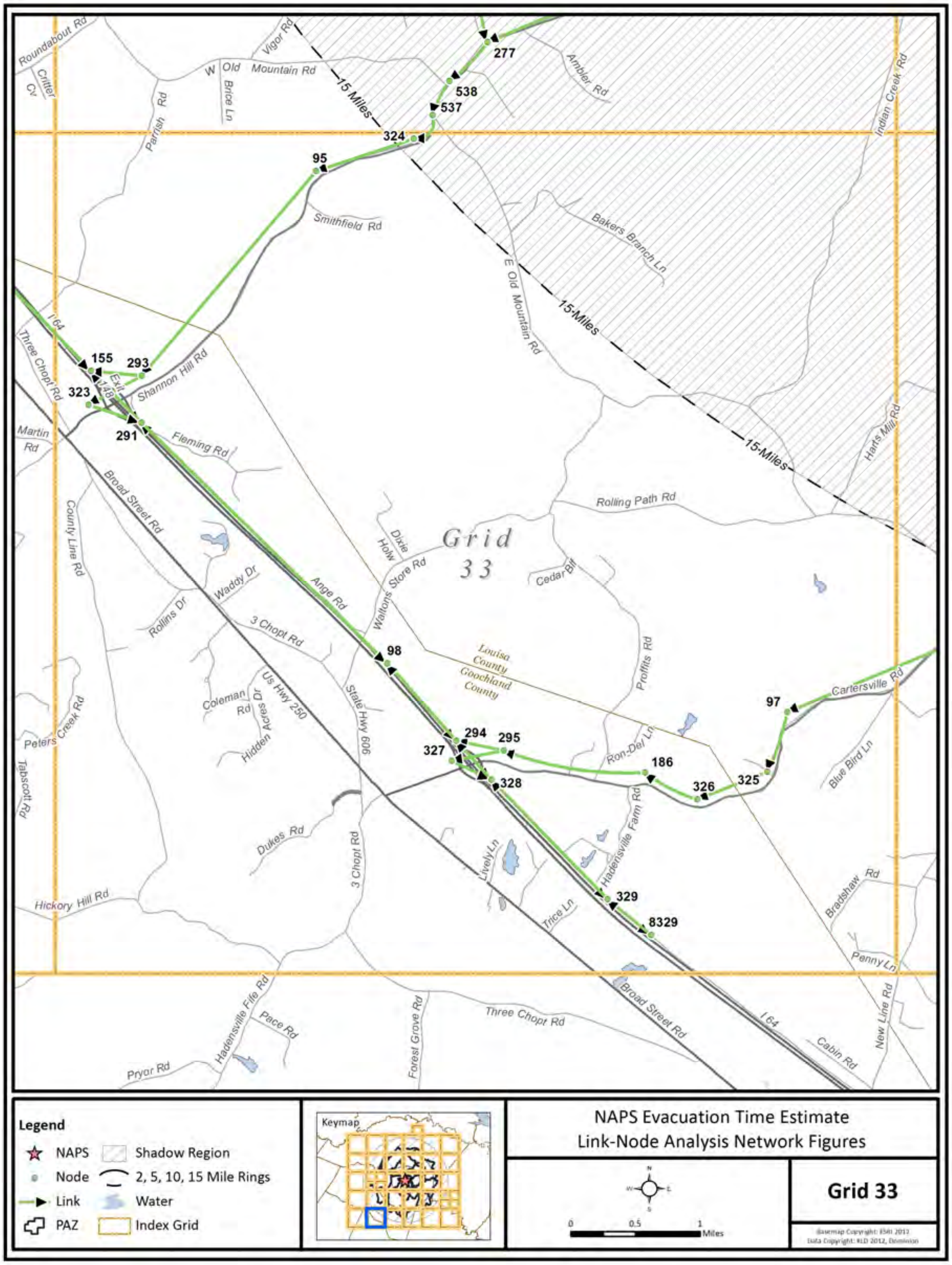


Figure K-34. Link-Node Analysis Network – Grid 33

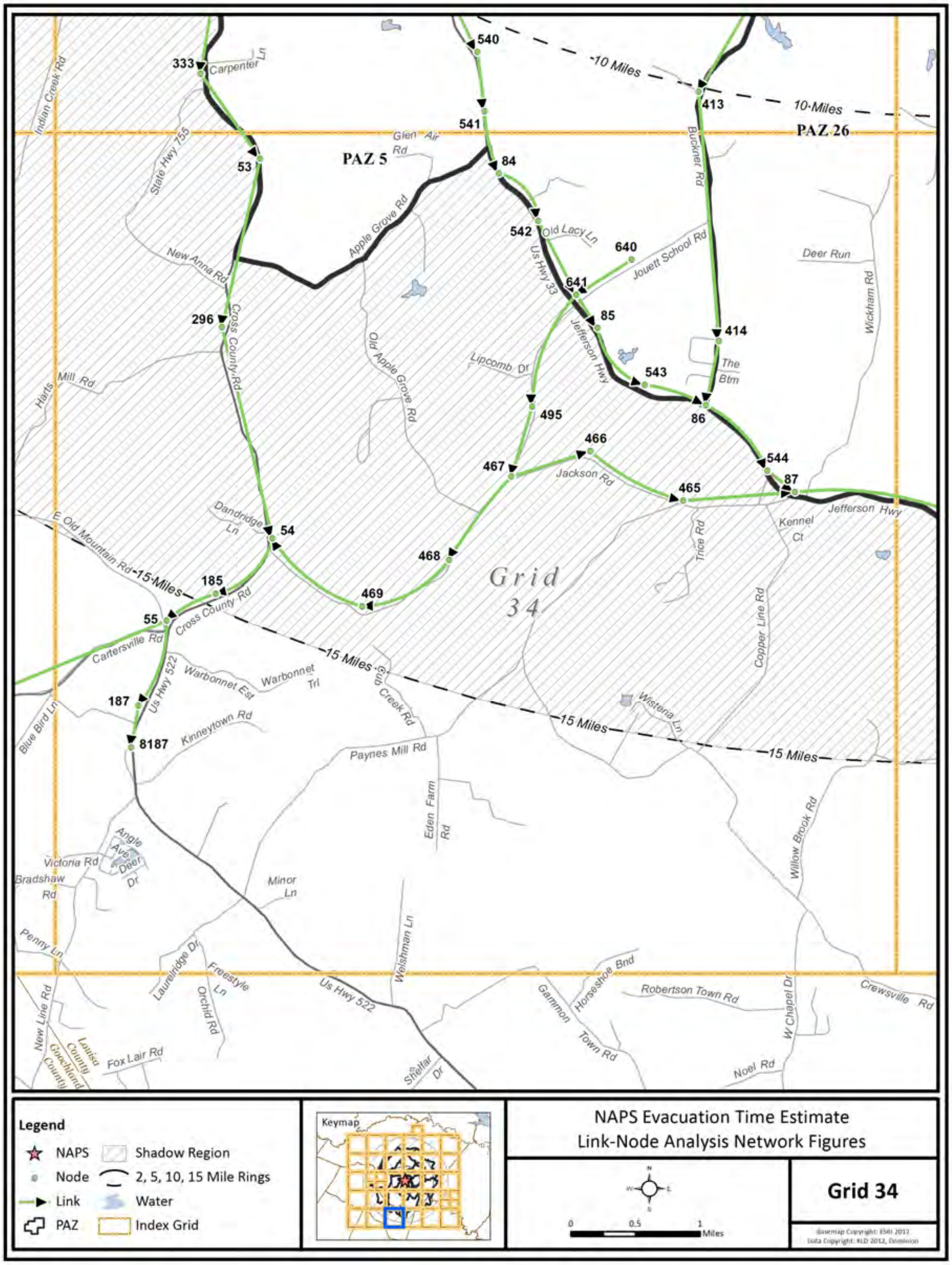


Figure K-35. Link-Node Analysis Network – Grid 34

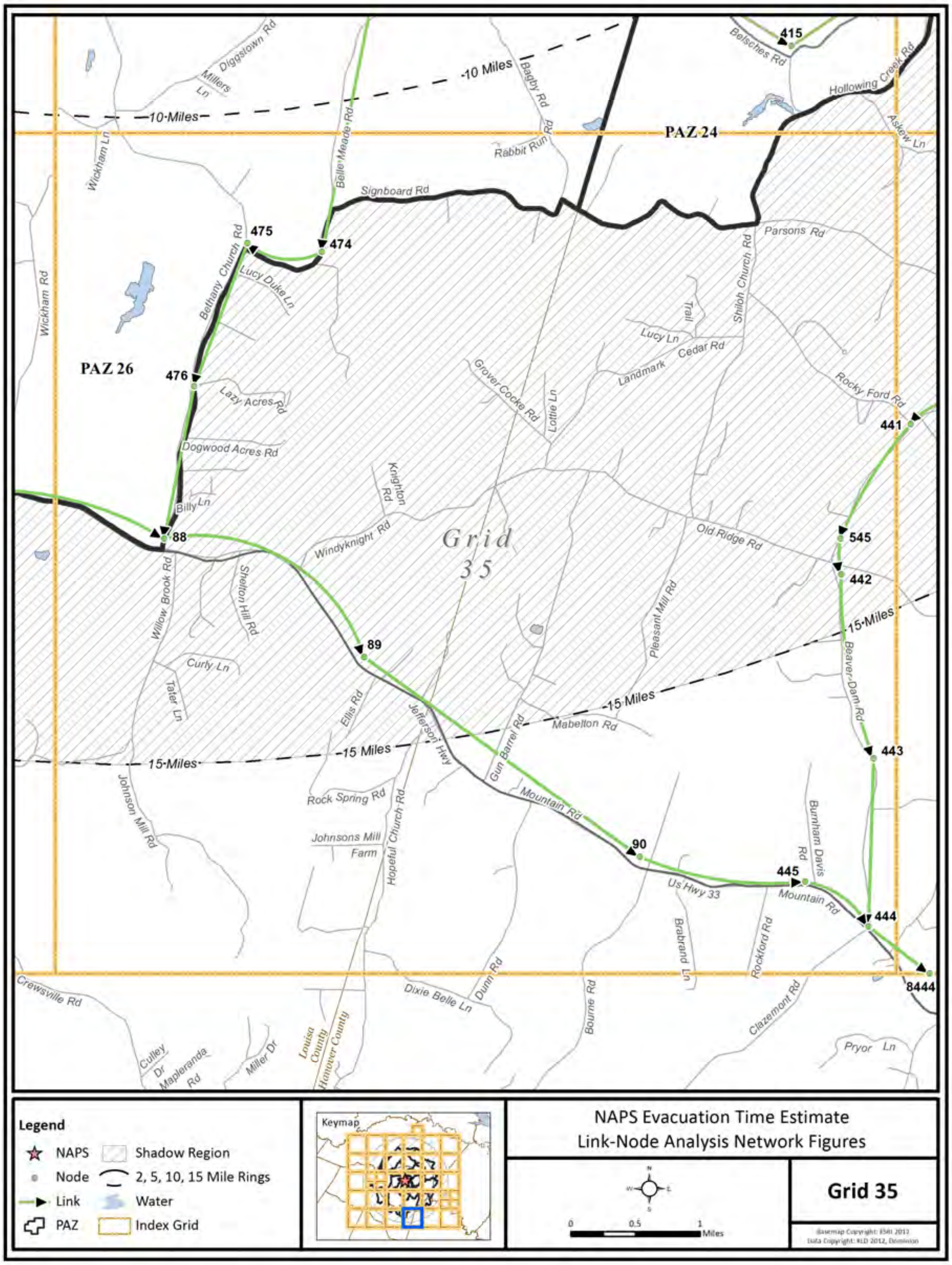


Figure K-36. Link-Node Analysis Network – Grid 35

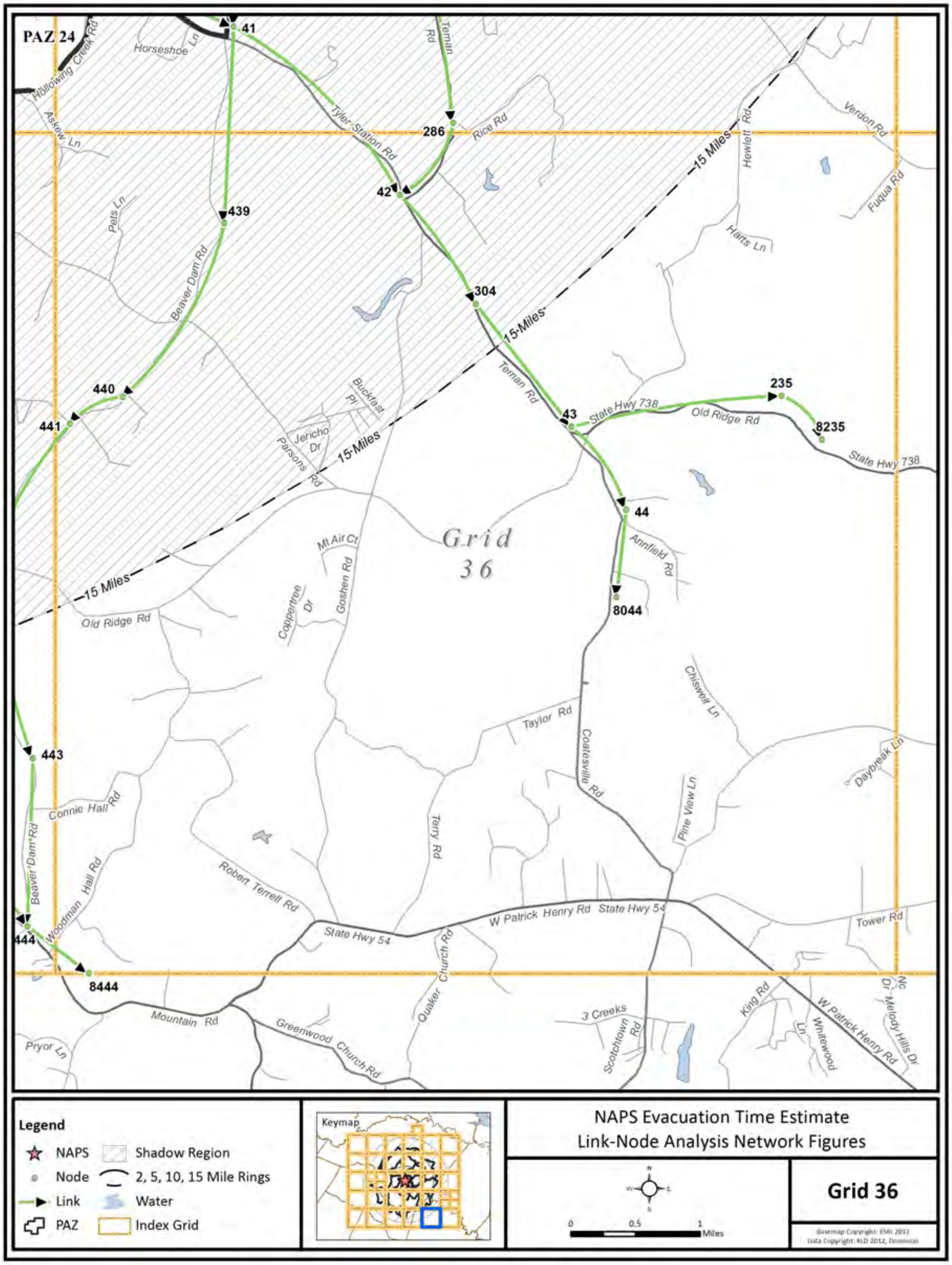


Figure K-37. Link-Node Analysis Network – Grid 36

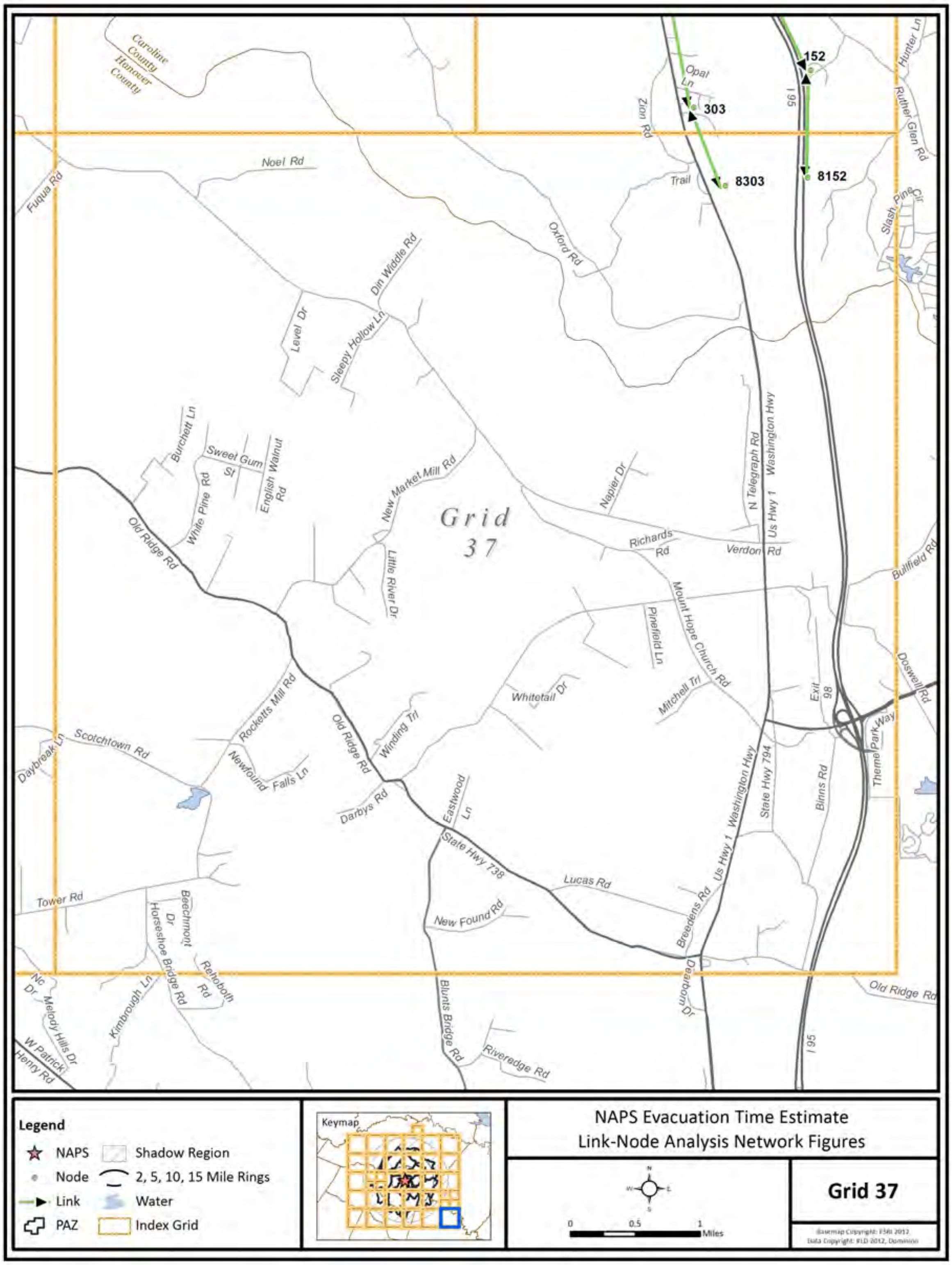


Figure K-38. Link-Node Analysis Network – Grid 37

Table K-1. Evacuation Roadway Network Characteristics

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
1	1	45	SR 603	COLLECTOR	2517	1	10	0	1700	55	21
2	2	194	SR 20	COLLECTOR	3683	1	12	3	1700	50	3
3	2	198	SR 20	COLLECTOR	5624	1	11	2	1700	60	3
4	2	231	US 522	COLLECTOR	3473	1	12	1	1700	60	3
5	3	510	US 522	COLLECTOR	351	1	12	1	1700	60	19
6	3	512	US 522	COLLECTOR	111	1	12	1	1700	60	19
7	4	347	SR 208	COLLECTOR	4353	1	12	1	1700	60	19
8	5	283	SR 208	COLLECTOR	7131	1	12	1	1700	60	20
9	6	144	CR 601	COLLECTOR	2655	1	11	0	1700	55	11
10	6	276	SR 208	COLLECTOR	5122	1	12	1	1700	60	11
11	7	378	SR 208	COLLECTOR	4774	1	12	1	1700	60	11
12	8	497	CR 606	COLLECTOR	3296	1	11	0	1750	50	12
13	9	10	SR 208	COLLECTOR	12530	1	12	1	1750	50	12
14	9	379	LAKE ANNA PKWY	COLLECTOR	5265	1	12	0	1700	45	12
15	10	498	CR 606	COLLECTOR	1409	1	12	0	1700	40	12
16	10	499	SR 208	COLLECTOR	1642	1	12	0	1700	40	12
17	11	12	CR 606	COLLECTOR	8027	1	12	0	1700	55	13
18	12	288	CR 606	COLLECTOR	1849	1	12	0	1750	40	13
19	13	35	US 522	COLLECTOR	4037	1	12	1	1700	60	10
20	14	482	US 522	COLLECTOR	5636	1	12	1	1750	60	9
21	15	195	US 522	COLLECTOR	15727	1	12	1	1700	60	3
22	16	232	SR 20	COLLECTOR	4864	1	12	3	1700	60	4
23	16	370	SR 20	COLLECTOR	3236	1	12	3	1700	60	4
24	17	16	SR 621	COLLECTOR	3855	1	10	0	1700	50	4

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
25	18	191	SR 621	COLLECTOR	5721	1	10	0	1700	50	4
26	18	311	SR 621	COLLECTOR	9916	1	10	0	1700	50	4
27	19	373	CR 621	COLLECTOR	6009	1	10	0	1700	50	5
28	19	374	CR 621	COLLECTOR	2969	1	10	0	1700	50	5
29	20	190	CR 621	COLLECTOR	11577	1	10	0	1700	50	1
30	20	223	CR 613	COLLECTOR	3304	1	12	0	1700	50	1
31	20	238	CR 621	COLLECTOR	3408	1	10	0	1700	50	1
32	21	193	CR 606	COLLECTOR	5144	1	11	0	1700	50	4
33	22	192	CR 606	COLLECTOR	6859	1	11	0	1700	50	4
34	23	285	CR 606	COLLECTOR	2892	1	11	0	1700	50	11
35	23	489	CR 606	COLLECTOR	7531	1	11	0	1700	50	11
36	24	306	CR 612	COLLECTOR	2615	1	10	0	1700	45	6
37	24	310	CR 613	COLLECTOR	2306	1	12	0	1700	50	6
38	25	225	CR 627	COLLECTOR	5717	1	12	2	1700	45	6
39	25	308	CR 613	COLLECTOR	6944	1	12	0	1700	50	6
40	26	224	SR 208 BUS	LOCAL ROADWAY	3232	1	12	4	1750	25	6
41	26	307	CR 613	COLLECTOR	3141	1	12	0	1750	40	6
42	27	270	CR 608	COLLECTOR	3107	1	12	0	1700	45	12
43	27	501	SR 208	COLLECTOR	2544	1	12	0	1700	40	6
44	28	255	CR 608	COLLECTOR	5503	1	12	0	1700	45	13
45	30	213	SR 20	COLLECTOR	4416	1	11	2	1700	60	3
46	30	368	SR 20	COLLECTOR	5866	1	11	2	1700	60	3
47	31	214	SR 20	COLLECTOR	1827	1	11	2	1700	40	2
48	31	215	SR 20	COLLECTOR	5871	1	11	2	1700	40	2
49	32	361	CR 612	COLLECTOR	4349	1	10	0	1700	60	2

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
50	33	359	CR 612	COLLECTOR	9382	1	10	0	1700	60	9
51	34	301	CR 612	COLLECTOR	3718	1	10	0	1700	40	9
52	35	14	US 522	COLLECTOR	4699	1	12	1	1700	60	9
53	35	300	CR 612	COLLECTOR	1778	1	10	0	1700	40	9
54	36	199	SR 652	COLLECTOR	2394	1	12	0	1700	55	19
55	36	425	SR 652	COLLECTOR	2528	1	12	0	1700	50	19
56	36	433	SR 700	COLLECTOR	1984	1	11	0	1700	45	19
57	37	275	SR 652	COLLECTOR	5368	1	12	0	1700	50	20
58	37	604	SR 614	COLLECTOR	3849	1	10	0	1700	50	20
59	38	470	SR 652	COLLECTOR	2594	1	12	0	1700	50	26
60	39	471	SR 618	COLLECTOR	795	1	10	0	1700	45	26
61	40	415	SR 618	COLLECTOR	9198	1	10	0	1700	50	26
62	41	42	SR 658	COLLECTOR	9779	1	11	0	1700	40	27
63	41	439	SR 715	COLLECTOR	8043	1	12	1	1700	45	27
64	42	304	SR 738	COLLECTOR	5436	1	11	0	1700	50	36
65	43	44	SR 671	COLLECTOR	4091	1	11	0	1700	50	36
66	43	235	SR 738	COLLECTOR	8685	1	11	0	1700	50	36
67	45	69	SR 603	COLLECTOR	3183	1	10	0	1700	55	21
68	46	298	US 522	COLLECTOR	2149	1	12	1	1700	60	19
69	47	513	US 522	COLLECTOR	1364	1	12	1	1700	60	19
70	48	335	E 1ST ST	LOCAL ROADWAY	388	1	12	0	1750	20	19
71	49	334	US 522	COLLECTOR	4170	1	12	1	1700	60	25
72	50	51	US 33	COLLECTOR	3158	1	12	1	1700	60	25
73	50	81	US 33	COLLECTOR	7058	1	12	1	1700	60	25
74	51	52	US 522	COLLECTOR	1149	1	12	0	1700	45	25

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
75	51	82	US 33	COLLECTOR	6216	1	12	1	1700	60	25
76	52	331	US 522	COLLECTOR	3233	1	12	0	1700	45	25
77	53	296	US 522	COLLECTOR	7046	1	12	0	1700	60	34
78	54	185	US 522	COLLECTOR	3375	1	12	0	1700	60	34
79	55	97	SR 629	COLLECTOR	9753	1	11	0	1700	45	34
80	55	187	US 522	COLLECTOR	3716	1	12	0	1700	60	34
81	56	48	E 1ST ST	LOCAL ROADWAY	3092	1	10	0	1575	35	19
82	57	603	SR 618	COLLECTOR	2855	1	10	0	1700	50	19
83	58	274	SR 618	COLLECTOR	4111	1	10	0	1700	45	25
84	58	281	SR 618	COLLECTOR	3463	1	10	0	1700	45	25
85	59	599	SR 618	COLLECTOR	498	1	10	0	1575	35	25
86	59	600	SR 618	COLLECTOR	645	1	10	0	1575	35	25
87	60	248	SR 614	COLLECTOR	1190	1	10	0	1700	50	20
88	61	596	SR 618	COLLECTOR	1902	1	10	0	1700	50	26
89	62	409	SR 618	COLLECTOR	3810	1	10	0	1750	50	26
90	62	411	SR 609	COLLECTOR	5040	1	9	0	1700	45	26
91	63	64	SR 208	COLLECTOR	5804	1	12	1	1700	60	18
92	63	517	SR 208	COLLECTOR	2503	1	12	1	1700	50	18
93	64	63	SR 208	COLLECTOR	5804	1	12	1	1700	60	18
94	64	312	SR 208	COLLECTOR	3057	1	12	1	1700	60	18
95	65	66	SR 208	COLLECTOR	2156	1	12	1	1750	35	17
96	65	519	SR 208	COLLECTOR	949	1	12	1	1575	35	17
97	66	65	SR 208	COLLECTOR	2156	1	12	1	1750	35	17
98	66	166	US 33	COLLECTOR	724	1	12	1	1750	30	17
99	66	168	SR 208	COLLECTOR	1987	1	12	1	1700	45	17

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
100	67	170	US 33	COLLECTOR	1219	1	12	4	1750	30	17
101	67	338	US 33	COLLECTOR	4520	1	12	1	1700	45	17
102	68	70	US 33	COLLECTOR	4690	1	11	0	1700	55	14
103	68	73	SR 22	COLLECTOR	4198	1	11	0	1700	45	14
104	68	341	US 33	COLLECTOR	3041	1	11	1	1700	55	14
105	69	124	SR 603	COLLECTOR	6115	1	10	0	1700	55	21
106	70	68	US 33	COLLECTOR	4684	1	11	0	1700	55	14
107	71	140	CR 601	COLLECTOR	3717	1	11	0	1700	55	10
108	71	559	CR 601	COLLECTOR	4229	1	11	0	1700	60	10
109	72	558	STATE PARK LN	LOCAL ROADWAY	3223	1	10	0	1575	35	10
110	74	79	CR 601	COLLECTOR	2875	1	9	0	1700	45	10
111	74	125	CR 612	COLLECTOR	3075	1	10	0	1700	40	10
112	74	486	CR 612	COLLECTOR	6467	1	10	0	1700	40	10
113	75	76	SR 208	COLLECTOR	8873	1	12	1	1700	60	24
114	76	77	SR 208	COLLECTOR	9019	1	12	1	1700	60	23
115	77	78	SR 208	COLLECTOR	5191	1	12	1	1700	60	23
116	78	535	SR 208	COLLECTOR	1888	1	12	1	1700	45	23
117	79	91	CR 601	COLLECTOR	2322	1	9	0	1700	45	10
118	80	313	US 33	COLLECTOR	3951	1	12	1	1700	45	24
119	81	50	US 33	COLLECTOR	7058	1	12	1	1700	60	25
120	81	188	US 33	COLLECTOR	5432	1	12	1	1700	60	24
121	81	278	SR 605	COLLECTOR	2761	1	11	1	1700	50	24
122	82	83	US 33	COLLECTOR	4896	1	12	1	1700	60	25
123	83	435	US 33	COLLECTOR	1935	1	12	1	1700	60	25
124	84	542	US 33	COLLECTOR	2672	1	12	1	1700	60	34

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
125	85	543	US 33	COLLECTOR	3159	1	12	1	1700	60	34
126	86	544	US 33	COLLECTOR	3738	1	12	1	1700	60	34
127	87	88	US 33	COLLECTOR	8916	1	12	1	1700	60	35
128	88	89	US 33	COLLECTOR	10277	1	12	1	1700	60	35
129	89	90	US 33	COLLECTOR	13893	1	12	1	1700	60	35
130	90	445	US 33	COLLECTOR	6892	1	12	1	1700	60	35
131	91	96	CR 601	COLLECTOR	9884	1	11	0	1700	50	10
132	92	93	SR 605	COLLECTOR	4387	1	11	1	1700	60	24
133	93	539	SR 605	COLLECTOR	5768	1	11	1	1700	60	24
134	94	277	SR 605	COLLECTOR	4456	1	11	1	1700	60	24
135	95	293	SR 605	COLLECTOR	10964	1	11	1	1700	60	33
136	96	99	CR 601	COLLECTOR	9442	1	11	0	1700	50	4
137	97	325	SR 629	COLLECTOR	2564	1	11	0	1575	35	33
138	98	291	I-64	FREEWAY	14035	2	12	10	2250	75	33
139	98	294	I-64	FREEWAY	4235	2	12	10	2250	75	33
140	99	100	CR 601	COLLECTOR	2706	1	11	0	1700	50	4
141	100	21	CR 601	COLLECTOR	3980	1	11	0	1700	50	4
142	101	102	CR 612	COLLECTOR	3696	1	10	0	1700	40	10
143	102	103	CR 612	COLLECTOR	2074	1	10	0	1700	40	11
144	103	22	CR 606	COLLECTOR	3273	1	11	0	1700	50	11
145	104	103	CR 606	COLLECTOR	5217	1	11	0	1700	50	11
146	105	10	SR 738	COLLECTOR	2118	1	11	0	1750	50	12
147	106	588	SR 738	COLLECTOR	4229	1	11	0	1700	50	12
148	107	390	SR 738	COLLECTOR	2299	1	11	0	1700	50	21
149	107	406	SR 738	COLLECTOR	7642	1	11	0	1700	50	21

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
150	108	405	SR 738	COLLECTOR	1655	1	11	0	1700	40	21
151	108	406	SR 738	COLLECTOR	3781	1	11	0	1700	50	21
152	109	110	SR 738	COLLECTOR	9332	1	11	0	1700	50	21
153	110	111	SR 738	COLLECTOR	10608	1	11	0	1750	50	21
154	111	112	SR 639	COLLECTOR	1997	1	10	0	1700	50	27
155	111	118	SR 738	COLLECTOR	6747	1	11	0	1750	55	27
156	112	113	SR 658	COLLECTOR	4899	1	11	0	1700	55	27
157	112	315	SR 639	COLLECTOR	1191	1	10	0	1700	50	27
158	113	114	SR 658	COLLECTOR	9548	1	11	0	1700	55	27
159	113	258	SR 683	COLLECTOR	2796	1	8	0	1700	40	27
160	114	115	SR 658	COLLECTOR	8053	1	11	0	1700	55	28
161	115	116	SR 658	COLLECTOR	10193	1	11	0	1700	55	30
162	116	287	SR 658	COLLECTOR	6568	1	11	0	1700	55	31
163	117	135	US 1	MINOR ARTERIAL	12571	2	12	2	1900	60	29
164	117	302	US 1	MINOR ARTERIAL	6268	2	12	2	1750	60	31
165	118	111	SR 738	COLLECTOR	6754	1	11	0	1750	55	27
166	118	407	SR 738	COLLECTOR	6078	1	11	0	1700	55	27
167	119	286	SR 738	COLLECTOR	7719	1	11	0	1700	45	27
168	120	416	SR 652	COLLECTOR	9511	1	12	0	1700	50	26
169	120	595	SR 650	COLLECTOR	6780	1	10	0	1700	40	26
170	121	132	US 1	MINOR ARTERIAL	5589	2	12	2	1900	60	22
171	121	260	US 1	MINOR ARTERIAL	3686	2	12	2	1900	60	13
172	122	132	SR 605	COLLECTOR	3455	1	11	0	1700	40	22
173	122	318	CR 603	COLLECTOR	3656	1	10	0	1700	45	22
174	123	320	SR 603	COLLECTOR	1698	1	10	0	1700	55	22

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
175	124	123	SR 603	COLLECTOR	10327	1	10	0	1700	55	22
176	125	74	CR 612	COLLECTOR	3066	1	10	0	1700	40	10
177	125	130	CR 612	COLLECTOR	3715	1	10	0	1700	40	10
178	126	127	SR 639	COLLECTOR	3646	1	10	0	1750	50	22
179	127	133	US 1	MINOR ARTERIAL	15821	2	12	2	1900	60	22
180	127	134	US 1	MINOR ARTERIAL	7464	2	12	2	1900	60	22
181	127	250	SR 639	COLLECTOR	3712	1	10	0	1700	50	22
182	128	149	I-95	FREEWAY	1942	3	12	12	2250	75	22
183	128	150	I-95	FREEWAY	9282	3	12	12	2250	75	29
184	130	125	CR 612	COLLECTOR	3717	1	10	0	1700	40	10
185	130	136	CR 612	COLLECTOR	8426	1	10	0	1700	40	10
186	131	319	SR 683	COLLECTOR	4002	1	8	0	1700	40	28
187	132	121	US 1	MINOR ARTERIAL	5589	2	12	2	1900	60	22
188	132	133	US 1	MINOR ARTERIAL	10875	2	12	2	1900	60	22
189	132	254	SR 605	COLLECTOR	1187	1	11	0	1700	40	22
190	133	127	US 1	MINOR ARTERIAL	15821	2	12	2	1750	60	22
191	133	132	US 1	MINOR ARTERIAL	10875	2	12	2	1900	60	22
192	134	127	US 1	MINOR ARTERIAL	7464	2	12	2	1750	60	22
193	134	135	US 1	MINOR ARTERIAL	6786	2	12	2	1900	60	29
194	135	117	US 1	MINOR ARTERIAL	12571	2	12	2	1900	60	29
195	135	134	US 1	MINOR ARTERIAL	6786	2	12	2	1900	60	29
196	136	130	CR 612	COLLECTOR	8426	1	10	0	1700	40	10
197	136	137	CR 612	COLLECTOR	4504	1	10	0	1700	40	10
198	137	138	CR 612	COLLECTOR	2194	1	10	0	1700	40	10
199	138	560	CR 612	COLLECTOR	850	1	10	0	1350	30	10

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
200	138	638	CR 719	COLLECTOR	1609	1	10	0	1700	40	10
201	139	353	SR 719	COLLECTOR	2691	1	11	0	1700	50	10
202	140	71	CR 601	COLLECTOR	3716	1	11	0	1700	55	10
203	140	141	CR 601	COLLECTOR	2650	1	11	0	1700	55	11
204	141	140	CR 601	COLLECTOR	2653	1	11	0	1700	55	11
205	141	622	CR 601	COLLECTOR	3654	1	11	0	1700	55	11
206	142	8	CR 606	COLLECTOR	11391	1	11	0	1750	50	12
207	144	6	CR 601	COLLECTOR	2660	1	11	0	1700	55	11
208	144	622	CR 601	COLLECTOR	5015	1	11	0	1700	55	11
209	145	167	CR 606	COLLECTOR	2804	1	12	0	1700	45	13
210	146	212	I-95	FREEWAY	8652	3	12	12	2250	75	13
211	147	148	I-95	FREEWAY	14471	3	12	12	2250	75	22
212	147	207	I-95	FREEWAY	10424	3	12	12	2250	75	22
213	148	147	I-95	FREEWAY	14471	3	12	12	2250	75	22
214	148	149	I-95	FREEWAY	9252	3	12	12	2250	75	22
215	149	128	I-95	FREEWAY	1942	3	12	12	2250	75	22
216	149	148	I-95	FREEWAY	9252	3	12	12	2250	75	22
217	150	128	I-95	FREEWAY	9282	3	12	12	2250	75	29
218	150	151	I-95	FREEWAY	7390	3	12	12	2250	75	29
219	151	150	I-95	FREEWAY	7390	3	12	12	2250	75	29
220	151	208	I-95	FREEWAY	10054	3	12	12	2250	75	29
221	152	267	I-95	FREEWAY	6522	3	12	12	2250	75	31
222	153	158	CR 601	COLLECTOR	2811	1	10	0	1700	50	20
223	153	399	CR 601	COLLECTOR	7950	1	10	0	1700	50	20
224	154	41	SR 658	COLLECTOR	7017	1	9	0	1700	40	27

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
225	155	156	I-64	FREEWAY	27925	2	12	10	2250	75	23
226	155	291	I-64	FREEWAY	2954	2	12	10	2250	75	33
227	156	155	I-64	FREEWAY	27926	2	12	10	2250	75	23
228	156	290	I-64	FREEWAY	1828	2	12	10	2250	75	23
229	157	33	CR 612	COLLECTOR	5083	1	10	0	1700	60	9
230	158	159	CR 601	COLLECTOR	2378	1	10	0	1700	50	20
231	159	556	CR 601	COLLECTOR	3028	1	10	0	1700	50	20
232	160	6	SR 208	COLLECTOR	1696	1	12	1	1700	60	11
233	161	203	CR 655	COLLECTOR	1583	1	9	0	1700	45	19
234	162	213	SR 20	COLLECTOR	5821	1	11	2	1700	60	2
235	162	215	SR 20	COLLECTOR	7051	1	11	2	1700	60	2
236	163	80	US 33	COLLECTOR	1859	1	12	1	1700	60	24
237	163	165	US 33	COLLECTOR	5802	1	12	1	1700	60	24
238	164	163	MT AIRY RD	COLLECTOR	1969	1	9	0	1700	40	24
239	165	163	US 33	COLLECTOR	5802	1	12	1	1700	60	24
240	165	188	US 33	COLLECTOR	5281	1	12	1	1700	60	24
241	166	66	US 33	COLLECTOR	724	1	12	1	1750	30	17
242	166	170	US 33	COLLECTOR	634	1	12	4	1750	30	17
243	166	178	ROSEWOOD AVE	LOCAL ROADWAY	708	1	12	0	1125	25	17
244	168	66	SR 208	COLLECTOR	1987	1	12	1	1750	45	17
245	168	534	SR 208	COLLECTOR	844	1	12	1	1700	45	17
246	169	611	SR 207	MINOR ARTERIAL	1378	2	12	4	1750	50	31
247	170	67	US 33	COLLECTOR	1219	1	12	4	1350	30	17
248	170	166	US 33	COLLECTOR	634	1	12	4	1750	30	17
249	170	180	COURTHOUSE SQ	LOCAL ROADWAY	916	1	12	4	1125	25	17

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
250	171	7	SR 208	COLLECTOR	7451	1	12	1	1700	60	11
251	172	4	SR 208	COLLECTOR	5946	1	12	1	1750	60	19
252	173	507	CR 613	COLLECTOR	2335	1	12	0	1700	50	1
253	174	8	SR 208	COLLECTOR	4005	1	12	1	1750	50	12
254	174	497	LAKE ANNA PKWY	COLLECTOR	5873	1	12	10	1750	60	12
255	175	621	CR 612	COLLECTOR	1871	1	10	0	1700	40	2
256	176	28	CR 608	COLLECTOR	3844	1	12	0	1700	45	13
257	177	410	SR 618	COLLECTOR	5843	1	10	0	1700	50	26
258	178	180	WOOLFOLK AVE	LOCAL ROADWAY	621	1	12	0	1125	25	17
259	179	551	SR 738	COLLECTOR	3020	1	11	0	1700	45	27
260	180	168	ELM AVE	LOCAL ROADWAY	1346	1	12	4	1700	40	17
261	180	170	COURTHOUSE SQ	LOCAL ROADWAY	916	1	12	4	1750	25	17
262	181	500	SR 208	COLLECTOR	6178	1	12	0	1700	55	12
263	182	342	SR 208	COLLECTOR	3755	1	12	1	1700	50	18
264	182	519	SR 208	COLLECTOR	3235	1	12	1	1700	45	17
265	183	75	SR 208	COLLECTOR	5863	1	12	1	1700	60	24
266	183	534	SR 208	COLLECTOR	2252	1	12	1	1700	60	17
267	184	37	SR 652	COLLECTOR	4708	1	12	0	1700	50	20
268	185	55	US 522	COLLECTOR	2298	1	12	0	1700	60	34
269	186	295	SR 629	COLLECTOR	5871	1	11	0	1700	45	33
270	188	81	US 33	COLLECTOR	5432	1	12	1	1700	60	24
271	188	165	US 33	COLLECTOR	5281	1	12	1	1700	60	24
272	189	34	CR 612	COLLECTOR	3766	1	10	0	1700	40	9
273	190	20	CR 621	COLLECTOR	11577	1	10	0	1700	50	1
274	190	374	CR 621	COLLECTOR	8069	1	10	0	1700	60	5

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
275	191	18	SR 621	COLLECTOR	5721	1	10	0	1700	50	4
276	191	376	SR 621	COLLECTOR	2790	1	10	0	1700	50	4
277	192	458	CR 606	COLLECTOR	3742	1	11	0	1750	50	4
278	193	578	CR 606	COLLECTOR	1043	1	11	0	1575	35	4
279	194	2	SR 20	COLLECTOR	3683	1	12	3	1750	50	3
280	194	369	SR 20	COLLECTOR	8316	1	12	3	1700	50	3
281	195	2	US 522	COLLECTOR	2325	1	12	1	1750	60	3
282	196	15	US 522	COLLECTOR	9953	1	12	1	1700	60	3
283	197	350	US 522	COLLECTOR	2669	1	12	1	1700	60	19
284	198	2	SR 20	COLLECTOR	5624	1	11	2	1750	45	3
285	198	366	SR 20	COLLECTOR	3531	1	11	2	1700	60	3
286	199	607	SR 652	COLLECTOR	4396	1	12	0	1700	55	19
287	200	199	CENTERVILLE RD	LOCAL ROADWAY	4397	1	9	0	1700	40	19
288	201	605	SR 614	COLLECTOR	2987	1	12	0	1700	40	20
289	202	36	SR 700	COLLECTOR	982	2	11	0	1700	60	19
290	203	5	SR 208	COLLECTOR	3960	1	12	1	1700	60	20
291	203	509	SR 208	COLLECTOR	2705	1	12	1	1700	60	19
292	204	183	SR 646	COLLECTOR	7005	1	10	0	1700	40	24
293	205	13	US 522	COLLECTOR	2161	1	12	1	1700	60	10
294	206	211	I-95	FREEWAY	5135	3	12	12	2250	75	13
295	206	212	I-95	FREEWAY	4706	3	12	12	2250	75	13
296	207	147	I-95	FREEWAY	10424	3	12	12	2250	75	22
297	207	269	I-95	FREEWAY	5962	3	12	12	2250	75	13
298	208	151	I-95	FREEWAY	10054	3	12	12	2250	75	29
299	208	266	I-95	FREEWAY	3146	3	12	12	2250	75	31

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
300	209	204	SR 646	COLLECTOR	2676	1	10	0	1700	40	24
301	209	216	SR 646	COLLECTOR	2568	1	10	0	1700	40	24
302	211	206	I-95	FREEWAY	5135	3	12	12	2250	75	13
303	211	268	I-95	FREEWAY	5303	3	12	12	2250	75	13
304	212	146	I-95	FREEWAY	8652	3	12	12	2250	75	13
305	212	206	I-95	FREEWAY	4706	3	12	12	2250	75	13
306	213	30	SR 20	COLLECTOR	4416	1	11	2	1700	60	3
307	213	162	SR 20	COLLECTOR	5821	1	11	2	1700	60	2
308	214	31	SR 20	COLLECTOR	1827	1	11	2	1700	40	2
309	215	31	SR 20	COLLECTOR	5871	1	11	2	1700	40	2
310	215	162	SR 20	COLLECTOR	7051	1	11	2	1700	60	2
311	216	217	SR 646	COLLECTOR	5206	1	10	0	1700	40	24
312	217	218	SR 646	COLLECTOR	11844	1	10	0	1700	40	24
313	218	277	SR 646	COLLECTOR	5035	1	10	0	1700	40	24
314	219	166	SR 628	COLLECTOR	1856	1	10	0	1750	30	17
315	220	219	SR 628	COLLECTOR	3156	1	10	0	1700	50	17
316	221	220	SR 628	COLLECTOR	4095	1	10	0	1700	50	17
317	222	521	SR 628	COLLECTOR	430	1	10	0	1350	30	18
318	224	26	SR 208 BUS	LOCAL ROADWAY	3232	1	12	4	1750	25	6
319	224	307	SR 208	MINOR ARTERIAL	4910	1	12	0	1750	50	6
320	224	562	SR 208	MINOR ARTERIAL	1854	2	12	0	1900	50	6
321	226	562	SR 208	MINOR ARTERIAL	2251	2	12	0	1900	60	6
322	227	525	SR 628	COLLECTOR	2846	1	10	0	1700	40	16
323	228	227	SR 628	COLLECTOR	6204	1	10	0	1700	50	16
324	228	496	SR 613	COLLECTOR	5651	1	11	0	1700	50	16

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
325	229	504	CR 613	COLLECTOR	2328	1	12	0	1700	50	6
326	230	233	CR 613	COLLECTOR	2926	1	12	0	1700	50	6
327	232	16	SR 20	COLLECTOR	4864	1	12	3	1700	60	4
328	233	25	CR 613	COLLECTOR	2148	1	12	0	1700	50	6
329	234	236	CR 613	COLLECTOR	2897	1	12	0	1700	50	6
330	236	237	CR 613	COLLECTOR	5098	1	12	0	1700	50	6
331	237	173	CR 613	COLLECTOR	5255	1	12	0	1700	50	5
332	238	20	CR 621	COLLECTOR	3408	1	10	0	1700	50	1
333	239	240	US 522	COLLECTOR	2304	1	12	1	1700	60	9
334	240	196	US 522	COLLECTOR	7960	1	12	1	1700	60	9
335	241	447	SR 613	COLLECTOR	4135	1	12	0	1700	45	19
336	242	243	SR 625	COLLECTOR	4886	1	12	0	1700	45	16
337	243	244	SR 625	COLLECTOR	6056	1	12	0	1700	40	16
338	244	245	SR 625	COLLECTOR	3724	1	12	0	1700	40	18
339	245	246	SR 625	COLLECTOR	1866	1	12	0	1700	40	18
340	246	620	SR 625	COLLECTOR	4978	1	12	0	1700	45	18
341	247	249	SR 207	MINOR ARTERIAL	2014	2	12	4	1900	50	31
342	247	266	I-95 ON-RAMP FROM SR 207	FREEWAY RAMP	1624	1	12	4	1700	50	31
343	247	609	SR 207	MINOR ARTERIAL	783	2	12	4	1750	50	31
344	248	271	SR 614	COLLECTOR	5473	1	10	0	1700	50	20
345	249	247	SR 207	MINOR ARTERIAL	2014	2	12	4	1900	50	31
346	249	267	I-95 ON-RAMP FROM SR 207	FREEWAY RAMP	1365	1	12	4	1700	50	31
347	249	613	SR 207	MINOR ARTERIAL	449	1	12	4	1750	50	31

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
348	250	128	I-95 ON-RAMP FROM SR 639	FREEWAY RAMP	1171	1	12	6	1700	50	22
349	250	251	SR 639	COLLECTOR	1750	1	10	0	1700	50	22
350	251	129	SR 639	COLLECTOR	2756	1	10	0	1700	50	22
351	251	149	I-95 ON-RAMP FROM SR 639	FREEWAY RAMP	1348	1	12	6	1700	50	22
352	252	145	CR 606	COLLECTOR	1587	1	12	0	1700	45	13
353	252	268	I-95 ON-RAMP FROM CR 606	FREEWAY RAMP	1523	1	12	4	1700	50	13
354	253	252	CR 606	COLLECTOR	1736	1	12	0	1700	45	13
355	253	269	I-95 ON-RAMP FROM CR 606	FREEWAY RAMP	1066	1	12	4	1700	50	13
356	254	143	SR 605	COLLECTOR	4898	1	11	0	1700	40	22
357	255	264	CR 608	COLLECTOR	5147	1	12	0	1750	45	13
358	256	257	CR 608	COLLECTOR	2381	1	12	0	1700	45	13
359	258	131	SR 683	COLLECTOR	7384	1	8	0	1700	40	28
360	259	1	SR 603	COLLECTOR	3108	1	10	0	1700	55	21
361	260	121	US 1	MINOR ARTERIAL	3686	2	12	2	1900	60	13
362	260	289	US 1	MINOR ARTERIAL	2220	2	12	2	1900	60	13
363	261	262	US 1	MINOR ARTERIAL	4422	2	12	2	1900	60	13
364	261	288	US 1	MINOR ARTERIAL	5381	2	12	2	1750	60	13
365	262	261	US 1	MINOR ARTERIAL	4422	2	12	2	1900	60	13
366	262	263	US 1	MINOR ARTERIAL	4621	2	12	2	1900	60	13
367	263	262	US 1	MINOR ARTERIAL	4621	2	12	2	1900	60	13
368	263	264	US 1	MINOR ARTERIAL	7912	2	12	2	1750	60	13
369	264	256	CR 608	COLLECTOR	1953	1	12	0	1700	45	13

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
370	264	263	US 1	MINOR ARTERIAL	7912	2	12	2	1900	60	13
371	264	265	US 1	MINOR ARTERIAL	2404	2	12	2	1900	60	7
372	265	264	US 1	MINOR ARTERIAL	2404	2	12	2	1750	60	7
373	266	208	I-95	FREEWAY	3146	3	12	12	2250	75	31
374	266	267	I-95	FREEWAY	2285	3	12	12	2250	75	31
375	267	152	I-95	FREEWAY	6522	3	12	12	2250	75	31
376	267	266	I-95	FREEWAY	2285	3	12	12	2250	75	31
377	268	211	I-95	FREEWAY	5320	3	12	12	2250	75	13
378	268	269	I-95	FREEWAY	2220	3	12	12	2250	75	13
379	269	207	I-95	FREEWAY	5961	3	12	12	2250	75	13
380	269	268	I-95	FREEWAY	2220	3	12	12	2250	75	13
381	270	176	CR 608	COLLECTOR	7427	1	12	0	1700	45	12
382	271	272	SR 614	COLLECTOR	1855	1	10	0	1700	50	19
383	272	273	SR 614	COLLECTOR	2285	1	10	0	1700	50	25
384	273	59	SR 614	COLLECTOR	5084	1	10	0	1750	50	25
385	274	58	SR 618	COLLECTOR	4100	1	10	0	1700	45	25
386	274	600	SR 618	COLLECTOR	1471	1	10	0	1700	45	25
387	275	38	SR 652	COLLECTOR	4328	1	12	0	1700	50	20
388	276	171	SR 208	COLLECTOR	7438	1	12	1	1700	60	11
389	277	538	SR 605	COLLECTOR	2227	1	11	1	1700	60	24
390	278	92	SR 605	COLLECTOR	5823	1	11	1	1700	50	24
391	279	515	US 522	COLLECTOR	542	1	12	1	1350	30	25
392	280	50	US 522	COLLECTOR	3475	1	12	1	1700	60	25
393	281	58	SR 618	COLLECTOR	3454	1	10	0	1700	45	25
394	281	601	SR 618	COLLECTOR	1683	1	10	0	1700	45	25

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
395	282	172	SR 208	COLLECTOR	6084	1	12	1	1700	60	19
396	283	160	SR 208	COLLECTOR	2845	1	12	1	1700	60	11
397	284	142	CR 606	COLLECTOR	5743	1	11	0	1700	50	11
398	285	284	CR 606	COLLECTOR	5125	1	11	0	1700	50	11
399	286	42	SR 738	COLLECTOR	3760	1	11	0	1575	35	36
400	287	302	SR 658	COLLECTOR	4363	1	11	0	1750	55	31
401	288	253	CR 606	COLLECTOR	2496	1	12	0	1700	45	13
402	288	261	US 1	MINOR ARTERIAL	5381	2	12	2	1900	60	13
403	288	289	US 1	MINOR ARTERIAL	4875	2	12	0	1900	55	13
404	289	260	US 1	MINOR ARTERIAL	2220	2	12	2	1900	60	13
405	289	288	US 1	MINOR ARTERIAL	4875	2	12	0	1750	55	13
406	290	156	I-64	FREEWAY	1828	2	12	10	2250	75	23
407	290	330	I-64	FREEWAY	8286	2	12	10	2250	75	23
408	291	98	I-64	FREEWAY	14035	2	12	10	2250	75	33
409	291	155	I-64	FREEWAY	2954	2	12	10	2250	75	33
410	292	290	I-64 ON-RAMP FROM SR 208	FREEWAY RAMP	829	1	12	2	1700	50	23
411	292	322	SR 208	COLLECTOR	1033	1	12	1	1700	55	23
412	293	155	I-64 ON-RAMP FROM SR 605	FREEWAY RAMP	2083	1	12	6	1700	50	33
413	293	323	SR 605	COLLECTOR	2480	1	11	1	1700	40	33
414	294	98	I-64	FREEWAY	4235	2	12	10	2250	75	33
415	294	328	I-64	FREEWAY	2139	2	12	10	2250	75	33
416	295	294	I-64 ON-RAMP FROM SR 629	FREEWAY RAMP	1966	1	12	6	1700	50	33
417	295	327	SR 629	COLLECTOR	2172	1	11	0	1700	40	33

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
418	296	54	US 522	COLLECTOR	8870	1	12	0	1700	60	34
419	297	48	US 522	COLLECTOR	1150	1	15	0	1575	35	19
420	298	47	US 522	COLLECTOR	4717	1	12	1	1700	60	19
421	299	345	US 522	COLLECTOR	4595	1	12	1	1700	65	19
422	300	189	CR 612	COLLECTOR	2340	1	10	0	1700	40	9
423	301	354	CR 612	COLLECTOR	1465	1	10	0	1700	40	9
424	302	117	US 1	MINOR ARTERIAL	6268	2	12	2	1900	60	31
425	302	303	US 1	MINOR ARTERIAL	6581	2	12	2	1900	60	31
426	302	613	SR 207	MINOR ARTERIAL	1885	2	12	4	1750	50	31
427	303	302	US 1	MINOR ARTERIAL	6581	2	12	2	1750	60	31
428	304	43	SR 738	COLLECTOR	6358	1	11	0	1700	50	36
429	305	335	SR 208	COLLECTOR	1405	1	12	1	1750	40	19
430	305	517	SR 208	COLLECTOR	4082	1	12	1	1700	50	19
431	307	224	SR 208	MINOR ARTERIAL	4911	2	12	0	1750	50	6
432	307	229	CR 613	COLLECTOR	2888	1	12	0	1700	50	6
433	308	24	CR 613	COLLECTOR	7694	1	12	0	1700	50	6
434	309	505	CR 613	COLLECTOR	214	1	12	0	1575	35	6
435	310	234	CR 613	COLLECTOR	2975	1	12	0	1700	50	6
436	311	17	SR 621	COLLECTOR	4267	1	10	0	1700	50	4
437	312	64	SR 208	COLLECTOR	3048	1	12	1	1700	60	18
438	312	342	SR 208	COLLECTOR	2911	1	12	1	1700	50	18
439	313	65	US 33	COLLECTOR	5376	1	12	4	1750	40	17
440	314	598	SR 618	COLLECTOR	1554	1	10	0	1700	40	25
441	315	259	SR 603	COLLECTOR	5689	1	10	0	1700	55	21
442	315	316	SR 639	COLLECTOR	6769	1	10	0	1700	50	21

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
443	316	553	SR 639	COLLECTOR	903	1	10	0	1700	40	21
444	317	61	SR 618	COLLECTOR	2645	1	10	0	1700	50	26
445	318	121	CR 603	COLLECTOR	527	1	10	0	1700	40	13
446	319	134	SR 683	COLLECTOR	6767	1	8	0	1700	40	28
447	320	122	CR 603	COLLECTOR	5737	1	10	0	1700	50	22
448	321	4	SR 652	COLLECTOR	5497	1	12	0	1750	55	19
449	322	156	I-64 ON-RAMP FROM SR 208	FREEWAY RAMP	957	1	12	2	1700	50	23
450	323	291	I-64 ON-RAMP FROM SR 605	FREEWAY RAMP	2285	1	12	6	1700	50	33
451	324	95	SR 605	COLLECTOR	4207	1	11	1	1700	60	33
452	325	326	SR 629	COLLECTOR	3078	1	11	0	1575	35	33
453	326	186	SR 629	COLLECTOR	2413	1	11	0	1700	45	33
454	327	328	I-64 ON-RAMP FROM SR 629	FREEWAY RAMP	1810	1	12	6	1700	50	33
455	328	294	I-64	FREEWAY	2139	2	12	10	2250	75	33
456	328	329	I-64	FREEWAY	6800	2	12	10	2250	75	33
457	329	328	I-64	FREEWAY	6800	2	12	10	2250	75	33
458	330	290	I-64	FREEWAY	8286	2	12	10	2250	75	23
459	331	332	US 522	COLLECTOR	2086	1	12	0	1700	45	25
460	332	333	US 522	COLLECTOR	5980	1	12	0	1700	45	25
461	333	53	US 522	COLLECTOR	4258	1	12	0	1700	60	25
462	334	280	US 522	COLLECTOR	4260	1	12	1	1700	60	25
463	335	305	SR 208	COLLECTOR	1405	1	12	1	1700	40	19
464	335	514	US 522	COLLECTOR	1248	1	16	1	1700	40	19
465	336	335	E 1ST ST	LOCAL ROADWAY	611	1	12	0	1750	35	19

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
466	337	341	US 33	COLLECTOR	1320	1	12	4	1700	55	14
467	337	528	US 33	COLLECTOR	5859	1	12	1	1700	60	14
468	338	67	US 33	COLLECTOR	4520	1	12	1	1700	45	17
469	338	339	US 33	COLLECTOR	5422	1	12	1	1700	60	17
470	339	338	US 33	COLLECTOR	5422	1	12	1	1700	60	17
471	339	340	US 33	COLLECTOR	2480	1	12	1	1700	60	14
472	340	339	US 33	COLLECTOR	2480	1	12	1	1700	60	14
473	340	528	US 33	COLLECTOR	987	1	12	1	1700	55	14
474	341	68	US 33	COLLECTOR	3041	1	11	1	1700	55	14
475	341	337	US 33	COLLECTOR	1320	1	12	4	1700	55	14
476	342	182	SR 208	COLLECTOR	3746	1	12	1	1700	50	18
477	342	312	SR 208	COLLECTOR	2912	1	12	1	1700	50	18
478	343	46	US 522	COLLECTOR	2046	1	12	1	1700	60	19
479	344	343	US 522	COLLECTOR	2216	1	12	1	1700	60	19
480	345	346	US 522	COLLECTOR	1696	1	12	1	1700	65	19
481	346	344	US 522	COLLECTOR	3587	1	12	1	1700	60	19
482	347	348	SR 208	COLLECTOR	1425	1	12	1	1700	60	19
483	348	511	SR 208	COLLECTOR	1689	1	12	1	1700	45	19
484	349	352	US 522	COLLECTOR	3414	1	12	1	1700	60	19
485	350	351	US 522	COLLECTOR	3508	1	12	1	1700	60	10
486	351	205	US 522	COLLECTOR	2772	1	12	1	1700	60	10
487	352	197	US 522	COLLECTOR	4037	1	12	1	1700	60	19
488	353	561	SR 719	COLLECTOR	1042	1	11	0	1575	35	19
489	354	355	CR 612	COLLECTOR	7630	1	10	0	1700	40	9
490	355	356	CR 612	COLLECTOR	2707	1	10	0	1700	50	9

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
491	356	357	CR 612	COLLECTOR	2756	1	10	0	1700	40	9
492	357	358	CR 612	COLLECTOR	2037	1	10	0	1700	40	9
493	358	157	CR 612	COLLECTOR	1143	1	10	0	1700	40	9
494	359	360	CR 612	COLLECTOR	5214	1	10	0	1700	60	8
495	360	32	CR 612	COLLECTOR	4362	1	10	0	1700	60	8
496	361	362	CR 612	COLLECTOR	4745	1	10	0	1700	50	2
497	362	175	CR 612	COLLECTOR	1711	1	10	0	1700	40	2
498	363	364	CR 612	COLLECTOR	1706	1	10	0	1700	40	2
499	364	365	CR 612	COLLECTOR	3231	1	10	0	1700	40	2
500	365	31	CR 612	COLLECTOR	1787	1	10	0	1700	40	2
501	366	198	SR 20	COLLECTOR	3531	1	11	2	1700	60	3
502	366	367	SR 20	COLLECTOR	2878	1	11	2	1700	60	3
503	367	366	SR 20	COLLECTOR	2878	1	11	2	1700	60	3
504	367	368	SR 20	COLLECTOR	2819	1	11	2	1700	60	3
505	368	30	SR 20	COLLECTOR	5867	1	11	2	1700	60	3
506	368	367	SR 20	COLLECTOR	2819	1	11	2	1700	60	3
507	369	194	SR 20	COLLECTOR	8316	1	12	3	1700	50	3
508	369	370	SR 20	COLLECTOR	2695	1	12	3	1700	60	4
509	370	16	SR 20	COLLECTOR	3243	1	12	3	1700	60	4
510	370	369	SR 20	COLLECTOR	2695	1	12	3	1700	60	4
511	371	311	SR 692	COLLECTOR	4359	1	10	0	1700	50	4
512	372	371	SR 692	COLLECTOR	3224	1	10	0	1700	40	4
513	373	19	CR 621	COLLECTOR	6009	1	10	0	1700	50	5
514	373	375	SR 621	COLLECTOR	2628	1	10	0	1700	50	4
515	374	19	CR 621	COLLECTOR	2969	1	10	0	1700	50	5

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
516	374	190	CR 621	COLLECTOR	8069	1	10	0	1700	60	5
517	375	373	SR 621	COLLECTOR	2628	1	10	0	1700	50	4
518	375	376	SR 621	COLLECTOR	1816	1	10	0	1700	50	4
519	376	191	SR 621	COLLECTOR	2791	1	10	0	1700	50	4
520	376	375	SR 621	COLLECTOR	1816	1	10	0	1700	50	4
521	377	174	SR 208	COLLECTOR	2545	1	12	1	1700	60	12
522	378	377	SR 208	COLLECTOR	6324	1	12	1	1700	60	11
523	379	380	LAKE ANNA PKWY	COLLECTOR	2726	1	12	0	1700	55	12
524	380	563	LAKE ANNA PKWY	COLLECTOR	2892	1	12	0	1700	55	12
525	381	309	CR 648	COLLECTOR	5910	1	12	0	1700	45	6
526	381	502	CR 648	COLLECTOR	1180	1	11	0	1750	40	6
527	382	384	CR 648	COLLECTOR	2715	1	10	0	1700	45	12
528	383	382	CR 648	COLLECTOR	2215	1	10	0	1700	45	12
529	383	587	SR 738	COLLECTOR	1181	1	11	0	1700	40	12
530	384	385	CR 648	COLLECTOR	5167	1	10	0	1700	45	12
531	385	9	CR 648	COLLECTOR	7707	1	10	0	1750	45	12
532	386	105	SR 738	COLLECTOR	3094	1	11	0	1700	50	12
533	387	386	SR 738	COLLECTOR	4900	1	11	0	1700	50	12
534	388	106	SR 738	COLLECTOR	602	1	11	0	1700	50	12
535	389	388	SR 738	COLLECTOR	2897	1	11	0	1700	50	12
536	390	389	SR 738	COLLECTOR	4364	1	11	0	1700	50	21
537	391	392	BRENT'S LANDING RD	LOCAL ROADWAY	2978	1	10	0	1700	40	20
538	392	393	CR 601	COLLECTOR	5011	1	10	0	1700	50	20
539	392	397	CR 601	COLLECTOR	1052	1	10	0	1700	50	20

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
540	393	394	CR 601	COLLECTOR	1862	1	10	0	1700	50	20
541	394	422	CR 601	COLLECTOR	4897	1	10	0	1575	35	20
542	394	619	CR 622	COLLECTOR	2228	1	10	0	1700	45	20
543	395	396	CR 622	COLLECTOR	9238	1	10	0	1700	50	21
544	396	108	CR 622	COLLECTOR	1338	1	10	0	1700	50	21
545	397	392	CR 601	COLLECTOR	1052	1	10	0	1700	50	20
546	397	555	CR 601	COLLECTOR	975	1	10	0	1700	40	20
547	398	399	CR 601	COLLECTOR	3721	1	10	0	1700	50	20
548	398	555	CR 601	COLLECTOR	3482	1	10	0	1700	50	20
549	399	153	CR 601	COLLECTOR	7959	1	10	0	1700	50	20
550	399	398	CR 601	COLLECTOR	3715	1	10	0	1700	50	20
551	399	400	CR 614	COLLECTOR	7566	1	9	0	1700	40	20
552	400	401	CR 657	COLLECTOR	2537	1	9	0	1700	40	20
553	400	490	CR 614	COLLECTOR	5679	1	9	0	1700	40	20
554	401	402	CR 657	COLLECTOR	7017	1	9	0	1700	40	20
555	402	403	CR 657	COLLECTOR	4280	1	9	0	1700	40	20
556	403	404	CR 657	COLLECTOR	2494	1	9	0	1700	40	21
557	404	107	CR 657	COLLECTOR	1237	1	9	0	1700	40	21
558	405	109	SR 738	COLLECTOR	6204	1	11	0	1700	50	21
559	406	107	SR 738	COLLECTOR	7642	1	11	0	1700	50	21
560	406	108	SR 738	COLLECTOR	3774	1	11	0	1700	50	21
561	407	179	SR 738	COLLECTOR	3256	1	11	0	1700	45	27
562	408	317	SR 618	COLLECTOR	4330	1	10	0	1700	50	25
563	409	177	SR 618	COLLECTOR	4248	1	10	0	1700	50	26
564	410	39	SR 618	COLLECTOR	1702	1	10	0	1700	50	26

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
565	411	412	SR 609	COLLECTOR	9079	1	9	0	1700	45	25
566	412	413	SR 609	COLLECTOR	5465	1	9	0	1700	45	25
567	412	436	SR 612	COLLECTOR	1809	1	9	0	1700	40	25
568	413	414	SR 609	COLLECTOR	10254	1	9	0	1700	45	34
569	414	86	SR 609	COLLECTOR	2670	1	9	0	1750	40	34
570	415	154	SR 680	COLLECTOR	6182	1	10	0	1700	40	26
571	416	591	SR 601	COLLECTOR	421	1	10	0	1700	40	26
572	417	39	SR 701	COLLECTOR	6002	1	10	0	1700	50	26
573	418	416	SR 601	COLLECTOR	2939	1	10	0	1700	45	26
574	419	424	SR 601	COLLECTOR	5498	1	10	0	1700	40	26
575	420	419	SR 601	COLLECTOR	2649	1	10	0	1700	40	26
576	421	423	CR 601	COLLECTOR	3646	1	10	0	1700	40	20
577	422	421	CR 601	COLLECTOR	1600	1	10	0	1575	35	20
578	423	420	SR 601	COLLECTOR	3338	1	10	0	1700	40	20
579	424	593	SR 601	COLLECTOR	3294	1	10	0	1700	40	26
580	425	606	SR 652	COLLECTOR	5918	1	12	0	1700	50	20
581	426	202	SR 700	COLLECTOR	1391	1	11	0	1700	60	19
582	427	426	SR 700	COLLECTOR	3995	1	11	0	1700	60	19
583	428	429	SR 700	COLLECTOR	4310	1	11	0	1700	45	19
584	429	430	SR 700	COLLECTOR	4062	1	11	0	1700	45	19
585	430	431	SR 700	COLLECTOR	2486	1	11	0	1700	45	19
586	431	432	SR 700	COLLECTOR	4505	1	11	0	1700	45	19
587	432	434	SR 700	COLLECTOR	4382	1	11	0	1750	45	19
588	433	428	SR 700	COLLECTOR	2631	1	11	0	1700	45	19
589	434	57	SR 618	COLLECTOR	3692	1	10	0	1700	50	25

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
590	434	602	SR 618	COLLECTOR	698	1	10	0	1700	45	25
591	435	540	US 33	COLLECTOR	3115	1	12	1	1700	60	25
592	436	437	SR 612	COLLECTOR	6028	1	9	0	1700	40	25
593	437	435	SR 612	COLLECTOR	5683	1	9	0	1700	40	25
594	438	546	SR 715	COLLECTOR	1310	1	12	0	1575	35	27
595	439	440	SR 715	COLLECTOR	8312	1	12	1	1700	60	36
596	440	441	SR 715	COLLECTOR	2471	1	12	1	1700	60	36
597	441	545	SR 715	COLLECTOR	5503	1	12	1	1700	60	35
598	442	443	SR 715	COLLECTOR	7673	1	12	1	1700	60	35
599	443	444	SR 715	COLLECTOR	6864	1	12	1	1700	60	35
600	445	444	US 33	COLLECTOR	3263	1	12	1	1700	40	35
601	446	35	CR 612	COLLECTOR	2377	1	10	0	1700	40	10
602	447	228	SR 613	COLLECTOR	8380	1	12	0	1700	40	16
603	447	242	SR 625	COLLECTOR	4955	1	12	0	1700	40	16
604	448	526	SR 613	COLLECTOR	3212	1	11	0	1700	50	15
605	449	531	SR 613	COLLECTOR	8105	1	11	0	1700	50	14
606	450	573	CR 608	COLLECTOR	927	1	11	0	1700	40	5
607	450	574	CR 608	COLLECTOR	1477	1	12	0	1700	50	5
608	450	642	CR 612	COLLECTOR	611	1	10	0	1700	40	5
609	451	571	CR 608	COLLECTOR	2088	1	11	0	1700	50	6
610	452	570	CR 608	COLLECTOR	1007	1	11	0	1700	55	6
611	453	454	CR 612	COLLECTOR	6445	1	10	0	1700	40	5
612	454	24	CR 612	COLLECTOR	1531	1	10	0	1700	40	6
613	455	456	CR 608	COLLECTOR	8205	1	12	0	1700	50	5
614	456	575	CR 608	COLLECTOR	4389	1	12	0	1700	50	5

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
615	457	577	CR 608	COLLECTOR	3009	1	12	0	1700	50	4
616	458	21	CR 606	COLLECTOR	4826	1	12	0	1700	50	4
617	459	461	CR 605	COLLECTOR	7046	1	10	0	1700	40	21
618	459	625	CR 604	COLLECTOR	163	1	9	0	1700	40	21
619	460	617	CR 604	COLLECTOR	346	1	9	0	1125	25	21
620	461	462	CR 647	COLLECTOR	14625	1	9	0	1700	40	21
621	461	643	CR 605	COLLECTOR	807	1	10	0	1700	40	21
622	462	582	CR 647	COLLECTOR	3847	1	9	0	1750	40	12
623	463	464	CR 605	COLLECTOR	7668	1	10	0	1700	40	22
624	464	616	CR 605	COLLECTOR	444	1	10	0	1125	25	22
625	465	87	SR 601	COLLECTOR	4568	1	11	0	1700	40	34
626	466	465	SR 658	COLLECTOR	4327	1	10	0	1700	40	34
627	467	466	SR 658	COLLECTOR	3392	1	10	0	1700	40	34
628	467	468	SR 648	COLLECTOR	4251	1	11	0	1700	40	34
629	468	469	SR 648	COLLECTOR	4124	1	11	0	1700	40	34
630	469	54	SR 648	COLLECTOR	4678	1	11	0	1700	40	34
631	470	120	SR 652	COLLECTOR	5407	1	12	0	1700	50	26
632	471	472	SR 701	COLLECTOR	5004	1	10	0	1700	40	26
633	471	589	SR 618	COLLECTOR	1181	1	10	0	1700	45	26
634	472	473	SR 701	COLLECTOR	3635	1	10	0	1700	40	26
635	473	474	SR 701	COLLECTOR	10097	1	10	0	1700	40	26
636	474	475	SR 701	COLLECTOR	3223	1	10	0	1700	40	35
637	475	476	SR 655	COLLECTOR	6231	1	10	0	1700	40	35
638	476	88	SR 655	COLLECTOR	6340	1	10	0	1700	40	35
639	477	201	BURRUSS MILL RD	COLLECTOR	5638	1	10	0	1700	40	20

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
640	478	459	CR 605	COLLECTOR	4109	1	10	0	1700	40	21
641	479	478	CR 605	COLLECTOR	5690	1	10	0	1700	40	21
642	479	480	CR 605	COLLECTOR	4097	1	10	0	1700	40	21
643	480	481	CR 605	COLLECTOR	1656	1	10	0	1700	40	21
644	481	618	CR 605	COLLECTOR	220	1	10	0	1125	25	21
645	482	239	US 522	COLLECTOR	3007	1	12	1	1700	60	9
646	483	482	CR 719	COLLECTOR	6282	1	10	0	1750	40	10
647	484	483	CR 719	COLLECTOR	2193	1	10	0	1700	40	10
648	485	484	CR 719	COLLECTOR	4637	1	10	0	1700	40	10
649	486	101	CR 612	COLLECTOR	4486	1	10	0	1700	40	10
650	487	23	CR 659	COLLECTOR	4545	1	10	0	1700	40	11
651	488	171	CR 659	COLLECTOR	4782	1	10	0	1700	40	11
652	488	487	CR 659	COLLECTOR	4762	1	10	0	1700	40	11
653	489	104	CR 606	COLLECTOR	7727	1	11	0	1700	50	11
654	490	388	CR 614	COLLECTOR	16136	1	9	0	1700	40	11
655	491	479	CR 658	COLLECTOR	2411	1	9	0	1700	40	21
656	492	488	HARLEY LN	COLLECTOR	1305	1	9	0	1700	40	11
657	493	574	CR 612	COLLECTOR	2621	1	12	0	1350	30	5
658	494	209	SR 604	COLLECTOR	1333	1	8	0	1700	40	24
659	495	467	SR 648	COLLECTOR	2993	1	11	0	1700	40	34
660	496	448	SR 613	COLLECTOR	4968	1	11	0	1700	50	16
661	497	9	LAKE ANNA PKWY	COLLECTOR	3561	1	12	1	1750	50	12
662	498	11	CR 606	COLLECTOR	12047	1	12	0	1700	55	12
663	499	181	SR 208	COLLECTOR	8338	1	12	0	1700	55	12
664	500	27	SR 208	COLLECTOR	1050	1	12	0	1700	40	12

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
665	501	26	SR 208	COLLECTOR	538	1	12	0	1750	35	6
666	502	503	LAKE ANNA PKWY	MINOR ARTERIAL	2374	2	12	6	1900	60	6
667	503	307	LAKE ANNA PKWY	MINOR ARTERIAL	2692	2	12	6	1750	60	6
668	504	309	CR 613	COLLECTOR	256	1	12	0	1575	35	6
669	505	506	CR 613	COLLECTOR	986	1	12	0	1700	50	6
670	506	230	CR 613	COLLECTOR	290	1	12	0	1575	35	6
671	507	508	CR 613	COLLECTOR	691	1	12	0	1700	40	1
672	508	20	CR 613	COLLECTOR	2837	1	12	0	1700	50	1
673	509	282	SR 208	COLLECTOR	1772	1	12	1	1700	60	19
674	510	241	SR 613	COLLECTOR	9914	1	12	0	1700	40	19
675	510	299	US 522	COLLECTOR	1967	1	12	1	1700	65	19
676	511	3	SR 208	COLLECTOR	101	1	12	4	1700	45	19
677	511	512	SR 208	COLLECTOR	145	1	12	0	1350	30	19
678	512	349	US 522	COLLECTOR	1868	1	12	1	1700	60	19
679	513	297	US 522	COLLECTOR	2555	1	12	1	1700	40	19
680	514	279	US 522	COLLECTOR	1805	1	12	1	1700	40	25
681	515	49	US 522	COLLECTOR	4596	1	12	1	1700	50	25
682	516	517	BUS GARAGE RD	LOCAL ROADWAY	915	1	11	0	1350	30	18
683	517	63	SR 208	COLLECTOR	2503	1	12	1	1700	50	18
684	517	305	SR 208	COLLECTOR	4082	1	12	1	1700	50	19
685	518	342	INDUSTRIAL DR	LOCAL ROADWAY	1220	1	11	0	1700	40	18
686	519	65	SR 208	COLLECTOR	947	1	12	1	1750	35	17
687	519	182	SR 208	COLLECTOR	3233	1	12	1	1700	45	17
688	520	221	SR 628	COLLECTOR	656	1	10	0	1575	35	17
689	521	520	SR 628	COLLECTOR	4439	1	10	0	1700	50	18

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
690	522	222	SR 628	COLLECTOR	1642	1	10	0	1575	35	18
691	524	522	SR 628	COLLECTOR	3610	1	10	0	1700	50	16
692	525	524	SR 628	COLLECTOR	3757	1	10	0	1700	50	16
693	526	527	SR 613	COLLECTOR	1739	1	11	0	1700	40	15
694	527	532	SR 613	COLLECTOR	3929	1	11	0	1700	50	15
695	528	337	US 33	COLLECTOR	5859	1	12	1	1700	60	14
696	528	340	US 33	COLLECTOR	989	1	12	1	1700	55	14
697	529	530	SR 613	COLLECTOR	2392	1	11	0	1700	50	14
698	530	337	SR 613	COLLECTOR	2006	1	11	0	1350	30	14
699	531	529	SR 613	COLLECTOR	3533	1	11	0	1700	50	14
700	532	533	SR 613	COLLECTOR	5097	1	11	0	1700	50	15
701	533	449	SR 613	COLLECTOR	5211	1	11	0	1700	50	15
702	534	168	SR 208	COLLECTOR	844	1	12	1	1700	45	17
703	534	183	SR 208	COLLECTOR	2252	1	12	1	1700	60	17
704	535	536	SR 208	COLLECTOR	1865	1	12	1	1700	50	23
705	536	292	SR 208	COLLECTOR	7090	1	12	1	1700	55	23
706	537	324	SR 605	COLLECTOR	1461	1	11	1	1700	45	24
707	538	537	SR 605	COLLECTOR	1564	1	11	1	1700	45	24
708	539	94	SR 605	COLLECTOR	2692	1	11	1	1700	45	24
709	540	541	US 33	COLLECTOR	2437	1	12	1	1700	60	25
710	541	84	US 33	COLLECTOR	2617	1	12	1	1700	60	34
711	542	641	US 33	COLLECTOR	3398	1	12	1	1700	60	34
712	543	86	US 33	COLLECTOR	2648	1	12	1	1750	60	34
713	544	87	US 33	COLLECTOR	1423	1	12	1	1700	60	34
714	545	442	SR 715	COLLECTOR	1479	1	12	1	1700	50	35

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
715	546	547	SR 715	COLLECTOR	960	1	12	1	1575	35	27
716	547	41	SR 715	COLLECTOR	5858	1	12	1	1700	60	27
717	548	550	SR 738	COLLECTOR	2690	1	11	0	1700	45	27
718	549	119	SR 738	COLLECTOR	1136	1	11	0	1700	45	27
719	550	549	SR 738	COLLECTOR	651	1	11	0	1125	25	27
720	551	552	SR 738	COLLECTOR	3429	1	11	0	1700	55	27
721	552	548	SR 738	COLLECTOR	2576	1	11	0	1700	40	27
722	553	554	SR 639	COLLECTOR	878	1	10	0	1700	50	22
723	554	126	SR 639	COLLECTOR	9644	1	10	0	1700	50	22
724	555	397	CR 601	COLLECTOR	949	1	10	0	1700	40	20
725	555	398	CR 601	COLLECTOR	3496	1	10	0	1700	50	20
726	556	557	CR 601	COLLECTOR	2444	1	10	0	1700	50	11
727	557	160	CR 601	COLLECTOR	1305	1	10	0	1700	50	11
728	558	71	STATE PARK LN	LOCAL ROADWAY	3301	1	10	0	1575	35	10
729	559	74	CR 601	COLLECTOR	1832	1	11	0	1700	50	10
730	560	139	SR 719	COLLECTOR	5574	1	11	0	1700	50	10
731	560	446	CR 612	COLLECTOR	10582	1	10	0	1700	40	10
732	561	352	SR 719	COLLECTOR	2728	1	11	0	1700	50	19
733	562	224	SR 208	MINOR ARTERIAL	1854	2	12	0	1750	50	6
734	562	226	SR 208	MINOR ARTERIAL	2251	2	12	0	1900	60	6
735	563	564	LAKE ANNA PKWY	MINOR ARTERIAL	3340	2	12	4	1900	55	12
736	564	502	LAKE ANNA PKWY	MINOR ARTERIAL	1768	2	12	4	1750	55	6
737	565	381	CR 608	COLLECTOR	1484	1	11	0	1700	50	6
738	566	452	CR 608	COLLECTOR	3837	1	11	0	1700	55	6
739	567	566	CR 608	COLLECTOR	5094	1	11	0	1700	55	6

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
740	568	567	CR 608	COLLECTOR	2663	1	11	0	1700	50	6
741	569	451	CR 608	COLLECTOR	4643	1	11	0	1700	50	5
742	570	565	CR 608	COLLECTOR	4341	1	11	0	1700	50	6
743	571	568	CR 608	COLLECTOR	653	1	11	0	1700	45	6
744	572	569	CR 608	COLLECTOR	2500	1	11	0	1700	40	5
745	573	572	CR 608	COLLECTOR	1532	1	11	0	1575	35	5
746	574	450	CR 608	COLLECTOR	1477	1	12	0	1700	50	5
747	574	455	CR 608	COLLECTOR	2775	1	12	0	1700	50	5
748	575	576	CR 608	COLLECTOR	4988	1	12	0	1700	50	5
749	576	457	CR 608	COLLECTOR	3649	1	12	0	1700	50	5
750	577	458	CR 608	COLLECTOR	4376	1	12	0	1750	50	4
751	578	579	SR 608	COLLECTOR	2035	1	11	0	1700	50	4
752	579	580	SR 608	COLLECTOR	2008	1	11	0	1700	50	4
753	580	18	SR 608	COLLECTOR	1951	1	11	0	1700	50	4
754	581	497	SPOTSYLVANIA SCHOOL RD	LOCAL ROADWAY	904	1	12	0	1750	30	12
755	582	387	SR 738	COLLECTOR	679	1	11	0	1700	40	12
756	583	582	SR 738	COLLECTOR	1941	1	11	0	1750	50	12
757	584	583	SR 738	COLLECTOR	1055	1	11	0	1700	40	12
758	585	584	SR 738	COLLECTOR	1141	1	11	0	1700	40	12
759	586	585	SR 738	COLLECTOR	2520	1	11	0	1700	50	12
760	587	586	SR 738	COLLECTOR	1001	1	11	0	1700	40	12
761	588	383	SR 738	COLLECTOR	1412	1	11	0	1700	40	12
762	589	40	SR 618	COLLECTOR	4115	1	10	0	1700	50	26
763	590	417	SR 701	COLLECTOR	1544	1	10	0	1700	40	26

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
764	591	590	SR 601	COLLECTOR	293	1	10	0	675	15	26
765	592	418	SR 601	COLLECTOR	3305	1	10	0	1700	40	26
766	593	592	SR 601	COLLECTOR	1010	1	10	0	1125	25	26
767	594	624	SR 650	COLLECTOR	282	1	10	0	1125	25	26
768	595	594	SR 650	COLLECTOR	2078	1	10	0	1700	40	26
769	596	62	SR 618	COLLECTOR	1997	1	10	0	1700	40	26
770	597	408	SR 618	COLLECTOR	4513	1	10	0	1700	50	25
771	598	597	SR 618	COLLECTOR	552	1	10	0	900	20	25
772	599	314	SR 618	COLLECTOR	2549	1	10	0	1700	50	25
773	600	59	SR 618	COLLECTOR	648	1	10	0	1750	35	25
774	600	274	SR 618	COLLECTOR	1469	1	10	0	1700	45	25
775	601	281	SR 618	COLLECTOR	1681	1	10	0	1700	45	25
776	601	602	SR 618	COLLECTOR	369	1	10	0	1350	30	25
777	602	434	SR 618	COLLECTOR	698	1	10	0	1750	45	25
778	602	601	SR 618	COLLECTOR	369	1	10	0	1350	30	25
779	603	56	SR 618	COLLECTOR	1861	1	10	0	1700	40	19
780	604	60	SR 614	COLLECTOR	847	1	10	0	1575	35	20
781	605	184	SR 614	COLLECTOR	1652	1	12	0	1700	40	20
782	606	184	SR 652	COLLECTOR	1581	1	12	0	1700	50	20
783	607	321	SR 652	COLLECTOR	4579	1	12	0	1700	55	19
784	608	124	SR 604	COLLECTOR	4840	1	9	0	1700	40	21
785	609	247	SR 207	MINOR ARTERIAL	778	2	12	4	1900	50	31
786	609	611	SR 207	MINOR ARTERIAL	2041	2	12	4	1750	50	31
787	610	609	SR 652	COLLECTOR	967	1	11	2	1750	45	31
788	611	169	SR 207	MINOR ARTERIAL	1378	2	12	4	1900	50	31

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
789	611	609	SR 207	MINOR ARTERIAL	2041	2	12	4	1750	50	31
790	612	611	RUTHER GLEN RD	LOCAL ROADWAY	589	1	11	2	1750	45	31
791	613	249	SR 207	MINOR ARTERIAL	449	3	12	4	1900	50	31
792	613	302	SR 207	MINOR ARTERIAL	1885	1	12	4	1750	50	31
793	614	613	SR F-160	LOCAL ROADWAY	308	1	10	0	1750	30	31
794	616	122	CR 605	COLLECTOR	2129	1	10	0	1700	40	22
795	617	608	CR 604	COLLECTOR	3438	1	9	0	1700	40	21
796	618	406	CR 605	COLLECTOR	3843	1	10	0	1700	40	21
797	619	395	CR 622	COLLECTOR	2293	1	10	0	1700	45	20
798	620	312	SR 625	COLLECTOR	373	1	12	0	1350	30	18
799	621	363	CR 612	COLLECTOR	2882	1	10	0	1700	40	2
800	622	141	CR 601	COLLECTOR	3658	1	11	0	1700	55	11
801	622	144	CR 601	COLLECTOR	5015	1	11	0	1700	55	11
802	623	622	CR 655	COLLECTOR	1320	1	9	0	1700	45	11
803	624	409	SR 650	COLLECTOR	911	1	10	0	1750	40	26
804	625	460	CR 604	COLLECTOR	4640	1	9	0	1700	40	21
805	626	96	CR 652	COLLECTOR	1169	1	10	0	1700	50	10
806	627	626	CR 652	COLLECTOR	936	1	10	0	1700	50	10
807	628	627	CR 652	COLLECTOR	2399	1	10	0	1700	50	10
808	629	628	CR 652	COLLECTOR	1147	1	10	0	1700	50	10
809	630	629	CR 652	COLLECTOR	3402	1	10	0	1700	50	10
810	631	630	CR 652	COLLECTOR	2211	1	10	0	1700	50	10
811	632	631	CR 652	COLLECTOR	1311	1	10	0	1700	50	10
812	633	632	CR 652	COLLECTOR	3358	1	10	0	1700	50	10
813	634	639	CR 652	COLLECTOR	1426	1	10	0	1700	40	10

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
814	635	634	CR 652	COLLECTOR	723	1	10	0	1700	40	10
815	636	635	CR 652	COLLECTOR	1482	1	10	0	1700	40	10
816	637	636	CR 719	COLLECTOR	1362	1	10	0	1700	40	10
817	637	638	CR 719	COLLECTOR	2175	1	10	0	1700	50	10
818	638	138	CR 719	COLLECTOR	1576	1	10	0	1700	40	10
819	638	637	CR 719	COLLECTOR	2175	1	10	0	1700	50	10
820	639	633	CR 652	COLLECTOR	1931	1	10	0	1700	50	10
821	640	641	SR 648	COLLECTOR	2679	1	11	0	1700	40	34
822	641	85	US 33	COLLECTOR	1609	1	12	1	1700	60	34
823	641	495	SR 648	COLLECTOR	4990	1	11	0	1700	40	34
824	642	453	CR 612	COLLECTOR	8798	1	10	0	1700	40	5
825	643	463	CR 605	COLLECTOR	5653	1	10	0	1700	40	21
826	644	118	TRIVETTE RD	LOCAL ROADWAY	1063	1	11	0	1700	40	27
827	8146	146	I-95	FREEWAY	2911	3	12	12	2250	75	7
828	8152	152	I-95	FREEWAY	4365	3	12	12	2250	75	31
829	8265	265	US 1	MINOR ARTERIAL	2025	2	12	2	1900	60	7
830	8303	303	US 1	MINOR ARTERIAL	3508	2	12	2	1900	60	37
831	8329	329	I-64	FREEWAY	2307	2	12	10	2250	75	33
Exit Link	235	8235	SR 738	COLLECTOR	2514	1	11	0	1700	50	36
Exit Link	257	8257	CR 608	COLLECTOR	3207	1	12	0	1700	45	13
Exit Link	146	8146	I-95	FREEWAY	2911	3	12	12	2250	75	7
Exit Link	152	8152	I-95	FREEWAY	4365	3	12	12	2250	75	31
Exit Link	169	8169	SR 207	MINOR ARTERIAL	1848	2	12	4	1900	50	31
Exit Link	44	8044	SR 671	COLLECTOR	3596	1	11	0	1700	50	36
Exit Link	226	8226	SR 208	MINOR ARTERIAL	3464	2	12	0	1900	60	6

Link #	Up-Stream Node	Down-Stream Node	Roadway Name	Roadway Type	Length (ft.)	No. of Lanes	Lane Width (ft.)	Shoulder Width (ft.)	Saturation Flow Rate (pcphpl)	Free Flow Speed (mph)	Grid Number
Exit Link	70	8070	US 33	COLLECTOR	2710	1	11	0	1700	55	14
Exit Link	73	8073	SR 22	COLLECTOR	2764	1	11	0	1700	45	14
Exit Link	129	8129	SR 639	COLLECTOR	2735	1	10	0	1700	50	22
Exit Link	143	8143	SR 605	COLLECTOR	1727	1	11	0	1700	40	22
Exit Link	167	8167	STONEWALL JACKSON RD	COLLECTOR	2067	1	12	0	1700	45	13
Exit Link	187	8187	US 522	COLLECTOR	1747	1	12	0	1700	60	34
Exit Link	223	8223	CR 613	COLLECTOR	2456	1	12	0	1700	50	1
Exit Link	225	8225	CR 627	COLLECTOR	4169	1	12	2	1700	45	6
Exit Link	231	8231	US 522	COLLECTOR	4645	1	12	1	1700	60	3
Exit Link	232	8016	SR 20	COLLECTOR	4855	1	12	3	1700	60	4
Exit Link	238	8238	CR 621	COLLECTOR	1957	1	10	0	1700	50	1
Exit Link	444	8444	US 33	COLLECTOR	3161	1	12	1	1700	40	36
Exit Link	265	8265	US 1	MINOR ARTERIAL	2025	2	12	2	1900	60	7
Exit Link	303	8303	US 1	MINOR ARTERIAL	3508	2	12	2	1900	60	37
Exit Link	214	8214	SR 20	COLLECTOR	1575	1	11	2	1700	40	2
Exit Link	329	8329	I-64	FREEWAY	2307	2	12	10	2250	75	33
Exit Link	330	8330	I-64	FREEWAY	6358	2	12	10	2250	75	23
Exit Link	306	8306	CR 612	COLLECTOR	2435	1	10	0	1700	45	6

Table K-2. Nodes in the Link-Node Analysis Network which are Controlled

Node	X Coordinate (ft)	Y Coordinate (ft)	Control Type	Grid Map Number
2	11638749	6780690	Actuated	3
3	11661508	6713177	TCP Uncontrolled	19
4	11668745	6714072	TCP Actuated	19
8	11723737	6745023	TCP Actuated	12
9	11730212	6743549	TCP Actuated	12
10	11741662	6738461	Actuated	12
16	11656309	6782910	Stop	4
18	11673093	6777797	Stop	4
20	11709946	6793806	Stop	1
21	11674684	6766769	Stop	4
23	11702430	6742414	Stop	11
24	11721873	6774782	Stop	6
26	11745039	6757906	Actuated	6
31	11597219	6771531	Stop	2
35	11650509	6730923	Stop	10
36	11679813	6701623	Stop	19
39	11701123	6663747	Stop	26
41	11725824	6656802	Stop	27
42	11732613	6649926	Stop	36
48	11653592	6687743	Stop	19
50	11654831	6669639	Stop	25
51	11655864	6666710	TCP Uncontrolled	25
54	11658771	6635919	Stop	34
56	11656682	6687839	Yield	19
59	11676068	6682941	TCP Actuated	25
65	11628791	6691103	Actuated	17
66	11626770	6691855	Actuated	17
68	11603959	6702751	Stop	14
71	11680218	6736288	Stop	10
86	11676467	6641362	TCP Actuated	34
87	11680097	6637805	Stop	34
88	11688666	6635927	Stop	35
96	11668513	6752671	Stop	10
100	11671767	6764094	TCP Uncontrolled	4
103	11686750	6754700	Stop	11
107	11722882	6714017	Stop	21
108	11724634	6702878	Stop	21

Node	X Coordinate (ft)	Y Coordinate (ft)	Control Type	Grid Map Number
111	11744285	6684255	TCP Actuated	27
112	11746267	6684497	Yield	27
118	11738815	6680524	TCP Actuated	27
121	11762334	6723100	Stop	13
122	11760583	6719400	Stop	22
124	11753489	6703852	Stop	22
127	11766960	6691244	Actuated	22
132	11763409	6717612	Stop	22
134	11769248	6684033	Stop	28
138	11663780	6728480	Stop	10
154	11719411	6659480	TCP Uncontrolled	27
160	11692947	6725191	Stop	11
163	11636244	6683679	Stop	24
166	11626237	6692346	Actuated	17
168	11625093	6690789	Stop	17
170	11625830	6692831	Actuated	17
171	11703556	6732071	Stop	11
180	11625245	6692126	Stop	17
182	11632902	6690365	TCP Uncontrolled	18
183	11624147	6687863	Stop	17
184	11688468	6698039	Stop	20
199	11678258	6703372	Stop	19
203	11684194	6717239	Stop	19
209	11626438	6678615	Stop	24
219	11627968	6693016	TCP Uncontrolled	17
224	11747296	6760219	Actuated	6
264	11767872	6755060	Actuated	13
277	11633233	6656172	Stop	24
288	11764372	6733405	Actuated	13
302	11777484	6659827	Actuated	31
307	11742420	6759640	Actuated	6
309	11737965	6762487	Stop	6
311	11663295	6779158	Stop	4
312	11639128	6691088	Yield	18
335	11653204	6687739	TCP Actuated	19
337	11608123	6701758	Stop	14
342	11636576	6689704	Stop	18
352	11659216	6717658	Stop	19

Node	X Coordinate (ft)	Y Coordinate (ft)	Control Type	Grid Map Number
355	11632154	6738156	Stop	9
497	11726651	6743506	Actuated	12
502	11738487	6756614	Actuated	6
512	11661550	6713280	Yield	19
517	11649482	6691247	Stop	18
641	11671165	6645863	Stop	34
526	11628255	6719167	Stop	15
546	11727108	6663426	Stop	27
574	11708424	6764505	Stop	5
582	11737280	6728970	TCP Actuated	12
593	11707918	6675692	Stop	26
609	11781777	6662831	Actuated	31
611	11783446	6664006	Actuated	31
613	11779090	6661023	Actuated	31
625	11742263	6708539	Stop	21
381	11737307	6756614	Stop	6
388	11724972	6722711	Stop	12
406	11724788	6706617	Stop	21
409	11692400	6669583	TCP Actuated	26
415	11714279	6656033	TCP Uncontrolled	26
416	11703038	6671616	Stop	26
434	11664681	6685714	TCP Actuated	25
435	11665757	6658568	Stop	25
444	11717412	6620093	Stop	35
448	11631193	6720438	TCP Uncontrolled	15
450	11709766	6765122	TCP Uncontrolled	5
458	11678340	6763683	TCP Actuated	4
459	11742148	6708654	TCP Uncontrolled	21
465	11675541	6637461	Stop	34
467	11668518	6638441	Stop	34
470	11693069	6682652	TCP Uncontrolled	26
475	11692070	6647984	TCP Uncontrolled	35
482	11647208	6740563	TCP Actuated	9
488	11699294	6734031	Stop	11

[1]Coordinates are in the North American Datum of 1983 Virginia North State Plane Zone

APPENDIX L

Protective Action Zone (PAZ) Boundaries

L. PROTECTIVE ACTION ZONE BOUNDARIES

PAZ 1	Not in Use
PAZ 2	County: Louisa Defined as the area within the following boundary: Town of Mineral
PAZ 3	County: Louisa Defined as the area within the following boundary: north by Routes 22 and 208, east by Routes 33, 522 and Mineral Town line, south by Routes 605 and 643, west by Routes 644, 33 and Louisa Town line
PAZ 4	County: Louisa Defined as the area within the following boundary: north by Route 208, east by Lake Anna, Contrary Creek and Routes 652 and 700, south by Routes 618 and 667, west by Routes 208 and 522
PAZ 5	County: Louisa Defined as the area within the following boundary: north by Route 618 and Mineral Town line, east by Route 609, south by Routes 33 and 657, west by Route 522
PAZ 6	County: Louisa Defined as the area within the following boundary: north by Route 652, east by Route 614, south by Route 618, west by Route 700
PAZ 7	County: Louisa Defined as the area within the following boundary: north by Route 652, east by Route 650, south by Route 618, west by Route 614
PAZ 8	County: Louisa Defined as the area within the following boundary: northeast by Lake Anna, southeast by Route 614, northwest by Contrary Creek, southwest by Route 652
PAZ 9	County: Spotsylvania Defined as the area within the following boundary: north by Routes 713 and 601, east by Route 614, south by Lake Anna, west by Route 208

PAZ 10 County: Louisa

Defined as the area within the following boundary: north by Lake Anna, east by Lake Anna and Route 622, south by Route 622, west by Routes 652 and 614

PAZ 11 County: Spotsylvania

Defined as the area within the following boundary: north by Route 657, east by Routes 738 and 622, south by Route 622, west by Lake Anna and Route 614

PAZ 12 County: Spotsylvania

Defined as the area within the following boundary: north by Bluff Run and Glebe Run, east by Route 738 and Oak Crest Drive, south by Routes 657, 614, 601 and 713, west by Route 208

PAZ 13 County: Spotsylvania

Defined as the area within the following boundary: north by Route 606, east by Routes 208 and 650, south by Route 208, west by Routes 601, 612 and 655

PAZ 14 County: Spotsylvania

Defined as the area within the following boundary: north by Route 601, east by Route 655, south by Lake Anna, west by Routes 612 and 719

PAZ 15 County: Louisa

Defined as the area within the following boundary: north by Lake Anna, east by Lake Anna, south by Route 208, west by Routes 522 and 719

PAZ 16 County: Louisa

Defined as the area within the following boundary: north by Lake Anna, east by Routes 719 and 522/208, south by Routes 22, 208 and Louisa Town line, west by Colonial Pipeline

PAZ 17 County: Orange

Defined as the area within the following boundary: north by Routes 653 and 629, east by Orange/Spotsylvania County line, south by Orange/Louisa County line (North Anna River), west by Colonial Pipeline

PAZ 18 County: Spotsylvania

Defined as the area within the following boundary: north by Routes 606 and 608, east by Routes 612 and 719, south by Spotsylvania/Louisa County line (North Anna River), west by Spotsylvania/Orange County line

PAZ 19 County: Spotsylvania

Defined as the area within the following boundary: north by Route 608, east by Route 612, south by Route 606, west by Route 606

PAZ 20 County: Spotsylvania

Defined as the area within the following boundary: north by Route 608, east by Routes 606 and 649, south by Route 208, west by Routes 606, 612 and 650

PAZ 21 County: Spotsylvania

Defined as the area within the following boundary: north by Routes 208 and 606, east by Routes 647 and 738, south by Route 605, west by Bluff Run, Glebe Run, Oak Crest Drive and Route 738

PAZ 22 County: Spotsylvania

Defined as the area within the following boundary: north by Routes 604 and 605, east by Spotsylvania/Caroline County line, south by North Anna River, west by Routes 622 and 738

PAZ 23 County: Caroline

Defined as the area within the following boundary: north by Route 738, east by Route 738, south by North Anna River, west by Spotsylvania/Caroline County line

PAZ 24 County: Hanover

Defined as the area within the following boundary: north by North Anna River, east by Route 738, south by Routes 608, 658, 680, 715, 729, 739 and 800, west by Hanover/Louisa County line

PAZ 25 County: Louisa

Defined as the area within the following boundary: north by North Anna River, east by Route 601, south by Route 652, west by Route 622

PAZ 26 County: Louisa

Defined as the area within the following boundary: north by North Anna River, east by Hanover/Louisa County line, south by Routes 33, 608, 655 and 701, west by Routes 601, 609, 650 and 652

APPENDIX M

Evacuation Sensitivity Studies

M. EVACUATION SENSITIVITY STUDIES

This appendix presents the results of a series of sensitivity analyses. These analyses are designed to identify the sensitivity of the ETE to changes in some base evacuation conditions.

M.1 Effect of Changes in Trip Generation Times

A sensitivity study was performed to determine whether changes in the estimated trip generation time have an effect on the ETE for the entire EPZ. Specifically, if the tail of the mobilization distribution were truncated (i.e., if those who responded most slowly to the Advisory to Evacuate, could be persuaded to respond much more rapidly), how would the ETE be affected? The case considered was Scenario 6, Region 3; a winter, midweek, midday, good weather evacuation of the entire EPZ. Table M-1 presents the results of this study.

Table M-1. Evacuation Time Estimates for Trip Generation Sensitivity Study

Trip Generation Period	Evacuation Time Estimate for Entire EPZ	
	90th Percentile	100th Percentile
3 Hours 30 Minutes	2:40	3:45
4 Hours 30 Minutes	2:40	4:40
5 Hours 30 Minutes (Base)	2:40	5:40

The results confirm the importance of accurately estimating the trip generation (mobilization) times. The ETE for the 100th percentile closely mirror the values for the time the last evacuation trip is generated. In contrast, the 90th percentile ETE is very insensitive to truncating the tail of the mobilization time distribution. As indicated in Section 7.3, traffic congestion within the EPZ clears at about 1 hour and 30 minutes after the ATE, well before the completion of trip generation time. The results indicate that programs to educate the public and encourage them toward faster responses for a radiological emergency, translates into shorter ETE at the 100th percentile. The results also justify the guidance to employ the [stable] 90th percentile ETE for protective action decision making.

M.2 Effect of Changes in the Number of People in the Shadow Region Who Relocate

A sensitivity study was conducted to determine the effect on ETE of changes in the percentage of people who decide to relocate from the Shadow Region. The case considered was Scenario 6, Region 3; a winter, midweek, midday, good weather evacuation for the entire EPZ. The movement of people in the Shadow Region has the potential to impede vehicles evacuating from an Evacuation Region within the EPZ. Refer to Sections 3.2 and 7.1 for additional information on population within the shadow region.

Table M-2 presents the evacuation time estimates for each of the cases considered. The results show that the ETE is not impacted by shadow evacuation from 0% to 20%. Tripling the shadow percentage has no effect on ETE. Note, the telephone survey results presented in Appendix F indicate that 19% of households would elect to evacuate if advised to shelter. Thus, the base assumption of 20% non-compliance suggested in NUREG/CR-7002 is valid.

Table M-2. Evacuation Time Estimates for Shadow Sensitivity Study

Percent Shadow Evacuation	Evacuating Shadow Vehicles	Evacuation Time Estimate for Entire EPZ	
		90th Percentile	100th Percentile
0	0	2:40	5:40
15	2,650	2:40	5:40
20 (Base)	3,533	2:40	5:40
60	10,599	2:40	5:40

M.3 Effect of Changes in EPZ Resident Population

A sensitivity study was conducted to determine the effect on ETE of changes in the resident population within the EPZ. As population in the EPZ changes over time, the time required to evacuate the public may increase, decrease, or remain the same. Since the ETE is related to the demand to capacity ratio present within the EPZ, changes in population will cause the demand side of the equation to change. The sensitivity study was conducted using the following planning assumptions:

1. The change in population within the EPZ was treated parametrically. The percent population change was varied between +100% and -85%. Changes in population were applied to permanent residents only (as per federal guidance), in both the EPZ area and the Shadow Region.
2. The transportation infrastructure remained fixed; the presence of new roads or highway capacity improvements were not considered.
3. The study was performed for the 2-Mile Region (R01), the 5-Mile Region (R02) and the entire EPZ (R03).
4. The good weather scenario which yielded the highest ETE values was selected as the case to be considered in this sensitivity study (Scenario 6).

Table M-3 presents the results of the sensitivity study. Section IV of Appendix E to 10 CFR Part 50, and NUREG/CR-7002, Section 5.4, require licensees to provide an updated ETE analysis to the NRC when a population increase within the EPZ causes ETE values (for the 2-Mile Region, 5-Mile Region or entire EPZ) to increase by 25 percent or 30 minutes, whichever is less. Note that all of the base ETE values are greater than 2 hours; 25 percent of the base ETE is always greater than 30 minutes. Therefore, 30 minutes is the lesser and is the criterion for updating.

Those percent population changes which result in ETE changes greater than 30 minutes are highlighted in red below – a 150% increase or 85% decrease in the EPZ population. Dominion will have to estimate the EPZ population on an annual basis. If the EPZ population increases by 150% or more, or decreases by 85% or more, an updated ETE analysis will be needed.

Table M-3. ETE Variation with Population Change

EPZ Resident Population	Base	Population Change			Base	Population Change		
		100%	135%	150%		-40%	-70%	-85%
	25,202	50,404	59,225	63,005	25,202	15,122	7,561	3,781
ETE for 90th Percentile								
Region	Base	Population Change			Base	Population Change		
		100%	135%	150%		-40%	-70%	-85%
2-MILE	2:30	2:35	2:40	2:40	2:30	2:25	2:10	1:55
5-MILE	2:30	2:35	2:40	2:40	2:30	2:25	2:15	1:55
FULL EPZ	2:40	2:50	3:00	3:10	2:40	2:35	2:30	2:10
ETE for 100th Percentile								
Region	Base	Population Change			Base	Population Change		
		100%	135%	150%		-40%	-70%	-85%
2-MILE	5:30	5:30	5:30	5:30	5:30	5:30	5:30	5:30
5-MILE	5:35	5:35	5:35	5:35	5:35	5:35	5:35	5:35
FULL EPZ	5:40	5:40	5:40	5:40	5:40	5:40	5:40	5:40

M.4 Effect of an Outage at the NAPS with Construction of New Unit 3

A sensitivity study was conducted to determine the effect on ETE from having an outage at the NAPS, concurrent with construction of the new unit. Outages may occur in spring (March/April) or fall (September/October) and typically last between 25 and 35 days. Data obtained from emergency management personnel at NAPS indicate there are an additional 900 employees (with a maximum shift of 450 employees) and an additional 150 Dominion/supplemental personnel per day for the Unit 3 construction project, resulting in a total of 600 additional employees. Using a vehicle occupancy factor of 1.04 obtained from the telephone survey, there are a total of 577 additional vehicles present at the plant during an outage.

ETE results shown in Table M-4 compare the outage to Scenario 6; a winter, midweek, midday, good weather evacuation of the 2-mile, 5-mile and full EPZ. Results indicate that the ETE are not affected by the additional plant employees, with the exception of the 90th percentile ETE for the 2-mile region, which decreased by 5 minutes. The decrease in the 90th percentile ETE is attributable to employees mobilizing at a quicker rate than the general population.

Table M-4. Evacuation Time Estimates for Outage

	Scenario 6 (Base)		Outage with Construction of New Unit 3	
Region	90th Percentile	100th Percentile	90th Percentile	100th Percentile
2-MILE	2:30	5:30	2:25	5:30
5-MILE	2:30	5:35	2:30	5:35
FULL EPZ	2:40	5:40	2:40	5:40

APPENDIX N

ETE Criteria Checklist

N. ETE CRITERIA CHECKLIST

Table N-1. ETE Review Criteria Checklist

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
1.0 Introduction		
a. The emergency planning zone (EPZ) and surrounding area should be described.	Yes	Section 1
b. A map should be included that identifies primary features of the site, including major roadways, significant topographical features, boundaries of counties, and population centers within the EPZ.	Yes	Figure 1-1
c. A comparison of the current and previous ETE should be provided and includes similar information as identified in Table 1-1, "ETE Comparison," of NUREG/CR-7002.	Yes	Table 1-3
1.1 Approach		
a. A discussion of the approach and level of detail obtained during the field survey of the roadway network should be provided.	Yes	Section 1.3
b. Sources of demographic data for schools, special facilities, large employers, and special events should be identified.	Yes	Section 2.1 Section 3
c. Discussion should be presented on use of traffic control plans in the analysis.	Yes	Section 1.3, Section 2.3, Section 9, Appendix G
d. Traffic simulation models used for the analyses should be identified by name and version.	Yes	Section 1.3, Appendix B, Appendix C, Appendix D

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
e. Methods used to address data uncertainties should be described.	Yes	Section 3 – avoid double counting Section 5, Appendix F – 4.15% sampling error at 95% confidence interval for telephone survey
1.2 Assumptions		
a. The planning basis for the ETE includes the assumption that the evacuation should be ordered promptly and no early protective actions have been implemented.	Yes	Section 2.3 – Assumption 1 Section 5.1
b. Assumptions consistent with Table 1-2, "General Assumptions," of NUREG/CR-7002 should be provided and include the basis to support their use.	Yes	Sections 2.2, 2.3
1.3 Scenario Development		
a. The ten scenarios in Table 1-3, Evacuation Scenarios, should be developed for the ETE analysis, or a reason should be provided for use of other scenarios.	Yes	Tables 2-1, 6-2
1.3.1 Staged Evacuation		
a. A discussion should be provided on the approach used in development of a staged evacuation.	Yes	Sections 5.4.2, 7.2
1.4 Evacuation Planning Areas		
a. A map of EPZ with emergency response planning areas (ERPAs) should be included.	Yes	Figure 6-1
b. A table should be provided identifying the ERPAs considered for each ETE calculation by downwind direction in each sector.	Yes	Table 6-1

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
c. A table similar to Table 1-4, "Evacuation Areas for a Staged Evacuation Keyhole," of NUREG/CR-7002 should be provided and includes the complete evacuation of the 2, 5, and 10 mile areas and for the 2 mile area/5 mile keyhole evacuations.	Yes	Table 7-5
2.0 Demand Estimation		
a. Demand estimation should be developed for the four population groups, including permanent residents of the EPZ, transients, special facilities, and schools.	Yes	Permanent residents, employees, transients – Section 3, Appendix E Special facilities, schools – Section 8, Appendix E
2.1 Permanent Residents and Transient Population		
a. The US Census should be the source of the population values, or another credible source should be provided.	Yes	Section 3.1
b. Population values should be adjusted as necessary for growth to reflect population estimates to the year of the ETE.	Yes	2010 used as the base year for analysis. No growth of population necessary.
c. A sector diagram should be included, similar to Figure 2-1, "Population by Sector," of NUREG/CR-7002, showing the population distribution for permanent residents.	Yes	Figure 3-2
2.1.1 Permanent Residents with Vehicles		
a. The persons per vehicle value should be between 1 and 2 or justification should be provided for other values.	Yes	1.81 persons per vehicle – Table 1-3
b. Major employers should be listed.	Yes	Appendix E – Table E-3
2.1.2 Transient Population		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. A list of facilities which attract transient populations should be included, and peak and average attendance for these facilities should be listed. The source of information used to develop attendance values should be provided.	Yes	Sections 3.3, 3.4, Appendix E
b. The average population during the season should be used, itemized and totaled for each scenario.	Yes	Tables 3-4, 3-5 and Appendix E itemize the transient population and employee estimates. These estimates are multiplied by the scenario specific percentages provided in Table 6-3 to estimate transient population by scenario.
c. The percent of permanent residents assumed to be at facilities should be estimated.	Yes	Sections 3.3, 3.4
d. The number of people per vehicle should be provided. Numbers may vary by scenario, and if so, discussion on why values vary should be provided.	Yes	Sections 3.3, 3.4
e. A sector diagram should be included, similar to Figure 2-1 of NUREG/CR-7002, showing the population distribution for the transient population.	Yes	Figure 3-6 – transients Figure 3-8 – employees
2.2 Transit Dependent Permanent Residents		
a. The methodology used to determine the number of transit dependent residents should be discussed.	Yes	Section 8.1, Table 8-1
b. Transportation resources needed to evacuate this group should be quantified.	Yes	Section 8.1, Tables 8-5, 8-10
c. The county/local evacuation plans for transit dependent residents should be used in the analysis.	Yes	Sections 8.1, 8.4

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
d. The methodology used to determine the number of people with disabilities and those with access and functional needs who may need assistance and do not reside in special facilities should be provided. Data from local/county registration programs should be used in the estimate, but should not be the only set of data.	Yes	Section 8.5
e. Capacities should be provided for all types of transportation resources. Bus seating capacity of 50% should be used or justification should be provided for higher values.	Yes	Section 2.3 – Assumption 10 Sections 3.5, 8.1, 8.2, 8.3
f. An estimate of this population should be provided and information should be provided that the existing registration programs were used in developing the estimate.	Yes	Table 8-1 – transit dependents Section 8.4 – special needs
g. A summary table of the total number of buses, ambulances, or other transport needed to support evacuation should be provided and the quantification of resources should be detailed enough to assure double counting has not occurred.	Yes	Section 8.3, 8.4 Table 8-5
2.3 Special Facility Residents		
a. A list of special facilities, including the type of facility, location, and average population should be provided. Special facility staff should be included in the total special facility population.	Yes	Appendix E, Table E-2 – list facility, type, location, and population
b. A discussion should be provided on how special facility data was obtained.	Yes	Section 8.3

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
c. The number of wheelchair and bed-bound individuals should be provided.	Yes	Section 3.5 Table E-2
d. An estimate of the number and capacity of vehicles needed to support the evacuation of the facility should be provided.	Yes	Section 8.3 Table 8-4
e. The logistics for mobilizing specially trained staff (e.g., medical support or security support for prisons, jails, and other correctional facilities) should be discussed when appropriate.	Yes	Sections 8.3, 8.4
2.4 Schools		
a. A list of schools including name, location, student population, and transportation resources required to support the evacuation, should be provided. The source of this information should be provided.	Yes	Table 8-2 Section 8.2
b. Transportation resources for elementary and middle schools should be based on 100% of the school capacity.	Yes	Table 8-2
c. The estimate of high school students who will use their personal vehicle to evacuate should be provided and a basis for the values used should be discussed.	Yes	Section 8.2
d. The need for return trips should be identified if necessary.	Yes	There are sufficient resources to evacuate schools in a single wave if transportation resources are shared between counties. However, Section 8.4 and Figure 8-1 discuss the potential for a multiple wave evacuation.

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
2.5.1 Special Events		
a. A complete list of special events should be provided and includes information on the population, estimated duration, and season of the event.	Yes	Section 3.7 Section 6
b. The special event that encompasses the peak transient population should be analyzed in the ETE.	Yes	Section 3.7
c. The percent of permanent residents attending the event should be estimated.	Yes	Section 3.7
2.5.2 Shadow Evacuation		
a. A shadow evacuation of 20 percent should be included for areas outside the evacuation area extending to 15 miles from the NPP.	Yes	Section 2.2 – Assumption 5 Figure 2-1 Section 3.2
b. Population estimates for the shadow evacuation in the 10 to 15 mile area beyond the EPZ are provided by sector.	Yes	Section 3.2 Figure 3-4 Table 3-3
c. The loading of the shadow evacuation onto the roadway network should be consistent with the trip generation time generated for the permanent resident population.	Yes	Section 5 – Table 5-9
2.5.3 Background and Pass Through Traffic		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. The volume of background traffic and pass through traffic is based on the average daytime traffic. Values may be reduced for nighttime scenarios.	Yes	Section 3.6 Table 3-6 Section 6 Table 6-3, 6-4
b. Pass through traffic is assumed to have stopped entering the EPZ about two hours after the initial notification.	Yes	Section 2.3 – Assumption 5 Section 3.6
2.6 Summary of Demand Estimation		
a. A summary table should be provided that identifies the total populations and total vehicles used in analysis for permanent residents, transients, transit dependent residents, special facilities, schools, shadow population, and pass-through demand used in each scenario.	Yes	Tables 3-7, 3-8
3.0 Roadway Capacity		
a. The method(s) used to assess roadway capacity should be discussed.	Yes	Section 4
3.1 Roadway Characteristics		
a. A field survey of key routes within the EPZ has been conducted.	Yes	Section 1.3
b. Information should be provided describing the extent of the survey, and types of information gathered and used in the analysis.	Yes	Section 1.3
c. A table similar to that in Appendix A, "Roadway Characteristics," of NUREG/CR-7002 should be provided.	Yes	Appendix K, Table K-1

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
d. Calculations for a representative roadway segment should be provided.	Yes	Section 4
e. A legible map of the roadway system that identifies node numbers and segments used to develop the ETE should be provided and should be similar to Figure 3-1, "Roadway Network Identifying Nodes and Segments," of NUREG/CR-7002.	Yes	Appendix K, Figures K-1 through K-38 present the entire link-node analysis network at a scale suitable to identify all links and nodes
3.2 Capacity Analysis		
a. The approach used to calculate the roadway capacity for the transportation network should be described in detail and identifies factors that should be expressly used in the modeling.	Yes	Section 4
b. The capacity analysis identifies where field information should be used in the ETE calculation.	Yes	Section 1.3, Section 4
3.3 Intersection Control		
a. A list of intersections should be provided that includes the total number of intersections modeled that are unsignalized, signalized, or manned by response personnel.	Yes	Appendix K, Table K-2
b. Characteristics for the 10 highest volume intersections within the EPZ are provided including the location, signal cycle length, and turn lane queue capacity.	Yes	Table J-1
c. Discussion should be provided on how signal cycle time is used in the calculations.	Yes	Section 4.1, Appendix C.
3.4 Adverse Weather		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. The adverse weather condition should be identified and the effects of adverse weather on mobilization time should be considered.	Yes	Table 2-1, Section 2.3 – Assumption 9 Mobilization time – Table 2-2, Section 5.3 (page 5-10)
b. The speed and capacity reduction factors identified in Table 3-1, "Weather Capacity Factors," of NUREG/CR-7002 should be used or a basis should be provided for other values.	Yes	Table 2-2 – based on HCM 2010. The factors provided in Table 3-1 of NUREG/CR-7002 are from HCM 2000.
c. The study identifies assumptions for snow removal on streets and driveways, when applicable.	Yes	Section 5.3 – page 5-10 Appendix F – Section F.3.3
4.0 Development of Evacuation Times		
4.1 Trip Generation Time		
a. The process used to develop trip generation times should be identified.	Yes	Section 5
b. When telephone surveys are used, the scope of the survey, area of survey, number of participants, and statistical relevance should be provided.	Yes	Appendix F
c. Data obtained from telephone surveys should be summarized.	Yes	Appendix F
d. The trip generation time for each population group should be developed from site specific information.	Yes	Section 5, Appendix F
4.1.1 Permanent Residents and Transient Population		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. Permanent residents are assumed to evacuate from their homes but are not assumed to be at home at all times. Trip generation time includes the assumption that a percentage of residents will need to return home prior to evacuating.	Yes	Section 5 discusses trip generation for households with and without returning commuters. Table 6-3 presents the percentage of households with returning commuters and the percentage of households either without returning commuters or with no commuters. Appendix F presents the percent households who will await the return of commuters.
b. Discussion should be provided on the time and method used to notify transients. The trip generation time discusses any difficulties notifying persons in hard to reach areas such as on lakes or in campgrounds.	Yes	Section 5.4.3
c. The trip generation time accounts for transients potentially returning to hotels prior to evacuating.	Yes	Section 5 Figure 5-1
d. Effect of public transportation resources used during special events where a large number of transients should be expected should be considered.	Yes	Section 3.7
e. The trip generation time for the transient population should be integrated and loaded onto the transportation network with the general public.	Yes	Section 5 Table 5-9
4.1.2 Transit Dependent Residents		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. If available, existing plans and bus routes should be used in the ETE analysis. If new plans should be developed with the ETE, they have been agreed upon by the responsible authorities.	Yes	Section 8.4 – pages 8-7, 8-8. Pre-established bus routes were used as defined in each of the counties RERP– see Figures 8-2, 8-3, 8-4, Table 8-10.
b. Discussion should be included on the means of evacuating ambulatory and non-ambulatory residents.	Yes	Section 8.4
c. The number, location, and availability of buses, and other resources needed to support the demand estimation should be provided.	Yes	Section 8.4 Table 8-5
d. Logistical details, such as the time to obtain buses, brief drivers, and initiate the bus route should be provided.	Yes	Section 8.4 Figure 8-1
e. Discussion should identify the time estimated for transit dependent residents to prepare and travel to a bus pickup point, and describes the expected means of travel to the pickup point.	Yes	Section 8.4
f. The number of bus stops and time needed to load passengers should be discussed.	Yes	Section 8.4
g. A map of bus routes should be included.	Yes	Figures 8-2, 8-3, 8-4
h. The trip generation time for non-ambulatory persons includes the time to mobilize ambulances or special vehicles, time to drive to the home of residents, loading time, and time to drive out of the EPZ should be provided.	Yes	Section 8.4

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
i. Information should be provided to supports analysis of return trips, if necessary.	Yes	Section 8.4 Figure 8-1 Tables 8-11, 8-12, 8-13
4.1.3 Special Facilities		
a. Information on evacuation logistics and mobilization times should be provided.	Yes	Section 8-4 Tables 8-14, 8-15, 8-16
b. Discussion should be provided on the inbound and outbound speeds.	Yes	Sections 8.4
c. The number of wheelchair and bed-bounds individuals should be provided, and the logistics of evacuating these residents should be discussed.	Yes	Section 8-4 Tables 8-14, 8-15, 8-16
d. Time for loading of residents should be provided	Yes	Section 8.4
e. Information should be provided that indicates whether the evacuation can be completed in a single trip or if additional trips should be needed.	Yes	Section 8.4 Tables 8-4, 8-5
f. If return trips should be needed, the destination of vehicles should be provided.	Yes	Return trips are not needed.
g. Discussion should be provided on whether special facility residents are expected to pass through the reception center prior to being evacuated to their final destination.	Yes	Section 8.4
h. Supporting information should be provided to quantify the time elements for the return trips.	Yes	Return trips are not needed.
4.1.4 Schools		

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
a. Information on evacuation logistics and mobilization time should be provided.	Yes	Section 8.4
b. Discussion should be provided on the inbound and outbound speeds.	Yes	School bus routes are presented in Table 8-6. School bus speeds are presented in Tables 8-7 (good weather), 8-8 (rain) and 8-9 (snow). Outbound speeds are defined as the minimum of the evacuation route speed and the State school bus speed limit. Inbound speeds are limited to the State school bus speed limit.
c. Time for loading of students should be provided.	Yes	Tables 8-7, 8-8, 8-9 Discussion in Section 8.4
d. Information should be provided that indicates whether the evacuation can be completed in a single trip or if additional trips are needed.	Yes	Section 8.4 – page 8-6 Table 8-2, 8-5
e. If return trips are needed, the destination of school buses should be provided.	Yes	Table 8-3
f. If used, reception centers should be identified. Discussion should be provided on whether students are expected to pass through the reception center prior to being evacuated to their final destination.	Yes	Table 8-3. Students are evacuated to Evacuation Assembly Centers (EAC) where they will be picked up by parents or guardians.

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
g. Supporting information should be provided to quantify the time elements for the return trips.	Yes	Return trips are needed for two of the schools. Tables 8-7, 8-8 and 8-9 provide time needed to arrive at the EAC, which could be used to compute a second wave evacuation. Example calculation is done in Section 8-4 – page 8-9
4.2 ETE Modeling		
a. General information about the model should be provided and demonstrates its use in ETE studies.	Yes	DYNEV II (Ver. 4.0.8.0) Section 1.3 Table 1-3 Appendix B and Appendix C
b. If a traffic simulation model is not used to conduct the ETE calculation, sufficient detail should be provided to validate the analytical approach used. All criteria elements should have been met, as appropriate.	No	Not applicable as a traffic simulation model was used.
4.2.1 Traffic Simulation Model Input		
a. Traffic simulation model assumptions and a representative set of model inputs should be provided.	Yes	Appendices B and C describe the simulation model assumptions and algorithms Table J-2
b. A glossary of terms should be provided for the key performance measures and parameters used in the analysis.	Yes	Appendix A Tables C-1, C-2

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
4.2.2 Traffic Simulation Model Output		
a. A discussion regarding whether the traffic simulation model used must be in equilibration prior to calculating the ETE should be provided.	Yes	Appendix B
b. The minimum following model outputs should be provided to support review: 1. Total volume and percent by hour at each EPZ exit node. 2. Network wide average travel time. 3. Longest queue length for the 10 intersections with the highest traffic volume. 4. Total vehicles exiting the network. 5. A plot that provides both the mobilization curve and evacuation curve identifying the cumulative percentage of evacuees who have mobilized and exited the EPZ. 6. Average speed for each major evacuation route that exits the EPZ.	Yes	1. Table J-5. 2. Table J-3. 3. Table J-1. 4. Table J-3. 5. Figures J-1 through J-14 (one plot for each scenario considered). 6. Table J-4. Network wide average speed also provided in Table J-3.
c. Color coded roadway maps should be provided for various times (i.e., at 2, 4, 6 hrs., etc.) during a full EPZ evacuation scenario, identifying areas where long queues exist including level of service (LOS) “E” and LOS “F” conditions, if they occur.	Yes	Figures 7-3 through 7-6
4.3 Evacuation Time Estimates for the General Public		
a. The ETE should include the time to evacuate 90% and 100% of the total permanent resident and transient population	Yes	Tables 7-1, 7-2

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
b. The ETE for 100% of the general public should include all members of the general public. Any reductions or truncated data should be explained.	Yes	Section 5.4.1 – truncating survey data to eliminate statistical outliers Table 7-2 – 100th percentile ETE for general public
c. Tables should be provided for the 90 and 100 percent ETEs similar to Table 4-3, "ETEs for Staged Evacuation Keyhole," of NUREG/CR-7002.	Yes	Tables 7-3, 7-4
d. ETEs should be provided for the 100 percent evacuation of special facilities, transit dependent, and school populations.	Yes	Section 8.4 Tables 8-7, 8-8, 8-9 Tables 8-11, 8-12, 8-13, 8-14, 8-15, 8-16
5.0 Other Considerations		
5.1 Development of Traffic Control Plans		
a. Information that responsible authorities have approved the traffic control plan used in the analysis should be provided.	Yes	Section 9, Appendix G
b. A discussion of adjustments or additions to the traffic control plan that affect the ETE should be provided.	Yes	Appendix G
5.2 Enhancements in Evacuation Time		
a. The results of assessments for improvement of evacuation time should be provided.	Yes	Section 13 Appendix M
b. A statement or discussion regarding presentation of enhancements to local authorities should be provided.	Yes	Results of the ETE study were formally presented to local authorities at the final project meeting. Recommended enhancements were discussed.

NRC Review Criteria	Criterion Addressed in ETE Analysis	Comments
5.3 State and Local Review		
a. A list of agencies contacted and the extent of interaction with these agencies should be discussed.	Yes	Table 1-1
b. Information should be provided on any unresolved issues that may affect the ETE.	Yes	There are no outstanding issues.
5.4 Reviews and Updates		
a. A discussion of when an updated ETE analysis is required to be performed and submitted to the NRC.	Yes	Appendix M, Section M.3
5.5 Reception Centers and Congregate Care Center		
a. A map of congregate care centers and reception centers should be provided.	Yes	Figure 10-1
b. If return trips are required, assumptions used to estimate return times for buses should be provided.	Yes	Section 8.4 discusses a multi-wave evacuation procedure. Figure 8-1
c. It should be clearly stated if it is assumed that passengers are left at the reception center and are taken by separate buses to the congregate care center.	Yes	Section 2.3 – Assumption 7h Section 10

Technical Reviewer ________________________________ Date __________________________

Supervisory Review ________________________________ Date __________________________

North Anna 3 Combined License Application

Part 7: Departures Report

(Includes Information on Departures, Variances, and Exemptions)

Revision 7

June 2016

REVISION SUMMARY

Revision 7

Section	Changes	Reason for Change
Departures, Introduction, DEP 19A-1	RAI 03.05.01.04-02, Missiles Generated by Tornadoes and Extreme Winds	
Departures, DEP 3.7-1	RAI 03.07.04-03, Seismic Instrumentation	
Departures, DEP 3.7-1, Summary of Departure	Changed "performance-based surface response spectra (PBSRS)" to "site-dependent SSE manifestation at grade"	Consistency with FSAR Section 3.7.1
Departures, DEP 3.7-1, Scope/Extent of Departure	Updated referenced FSAR sections	Incorporate NA3 site-specific SSI/SSSI and structural evaluation results and discuss performance and results of SMA
Departures, DEP 3.7-1, Departure Justification	Added reference to the SSI input response spectra for the FWSC at the average elevation of the bottom of the fill concrete	Consistency with FSAR Section 3.7.1
	Expanded the discussion to address design changes and structural acceptance criteria exceedances, and to clarify departure justification	Incorporate NA3 site-specific SSI/SSSI and structural evaluation results and discuss performance and results of SMA
Departures, DEP 3.7-1, Departure Evaluations	Clarified scope of departure evaluation; deleted unnecessary content in the departure evaluation	To clarify the scope of the departure to include those departures identified through site-specific analyses that result from the FIRS exceeding the CSDRS
Variances, Introduction, VAR 12.2-4	RAI 02.03.05-05, Modeling of Radwaste Building Vent Stack Releases	
Variances, VAR 2.0-4	Revised Request	EPRI 2013 GMM is current source
Exemptions, Exemption 3, Summary of Exemption	Added reference to the SSI input response spectra for the FWSC at the average elevation of the bottom of the fill concrete	Consistency with FSAR Section 3.7.1
Exemptions, Exemption 5	RAI 03.05.01.04-02, Missiles Generated by Tornadoes and Extreme Winds	

Revision 6

Section	Changes	Reason for Change
Departures, Introduction	Added second paragraph making reference to final certification rulemaking	Consistency with EF3 COLA and editorial change reflecting multiple departures
	Added NAPS DEP 3.7-1, NAPS DEP 8.1-1, NAPS DEP 8.1-2, & NAPS DEP 12.3-1	New departures
Departures, DEP 3.7-1	Added departure for Ground Response Spectra	New departure
Departures, DEP 8.1-1	Added departure for Electrical Power Distribution System	New departure
Departures, DEP 8.1-2	Added departure for On-site Power System SRP Criteria Applicability Matrix	New departure
Departures, DEP 11.4-1, Summary of Departure	Address the LWMS and SWMS	Consistency with EF3 COLA
Departures, DEP 11.4-1, Scope/Extent of Departure	Added references to all FSAR locations affected by NAPS DEP 11.4-1	Consistency with EF3 COLA
Departures, DEP 11.4-1, Departure Evaluation	Added new first paragraph stating departure affects Tier 2 information. Revised last paragraph to reference RG 1.206 and 10 CFR 52 Appendix E	Consistency with EF3 COLA
Departures, DEP 12.3-1	Added departure	NAPS DEP 12.3-1
Variances, Introduction	Revised NAPS ESP VAR 2.0-1 title	No longer a variance for χ/Q, only D/Q
	Added NAPS ESP VAR 2.3-1	New variance
	Added NAPS ESP VAR 2.4-3	New variance
	Added NAPS ESP VAR 2.4-4, “Lake Level Increase”	Consistency with US-APWR S-COLA
	Added NAPS ESP VAR 2.4-5	New variance
	Revised NAPS ESP VAR 2.5-2 entry to “Deleted”	No longer seeking variance
	Added NAPS ESP VAR 12.2-5	New variance
Variances, VAR 2.0-1	Revised	No longer a variance for χ/Q, only D/Q
Variances, VAR 2.0-2, Justification	Revised the maximum groundwater elevation values	Incorporate revised groundwater model

Revision 6 *(continued)*

Section	Changes	Reason for Change
Variances, VAR 2.0-3	Revised hydraulic gradient values	Consistency with US-APWR S-COLA
	Deleted metric units	Editorial
Variances, VAR 2.0-4	Revised variance to reflect ground motion response spectra	New GMRS based on CEUS and Mineral, VA earthquake
Variances, VAR 2.0-5	Revised variance	Revised analysis of accidental release of liquid radioactive waste
Variances, VAR 2.3-1	Added variance	Revised site characteristics for tornadoes and consistency with US-APWR S-COLA
Variances, VAR 2.4-1	Revised seepage velocity	Consistency with US-APWR S-COLA
	Deleted metric units	Editorial
Variances, VAR 2.4-3	Added variance	Consistency with US-APWR S-COLA (RAI 0.04.12-2); updated for well No. WP-3 and maximum groundwater elevations information
Variances, VAR 2.4-4	Added NAPS ESP VAR 2.4-4, “Lake Level Increase”	Consistency with US-APWR S-COLA
Variances, VAR 2.4-5	Added variance	Revised Lake Anna PMF analysis
Variances, VAR 2.5-2	Deleted variance	No longer seeking variance
Variances, VAR 12.2-1	Revised variance	Consistency with FSAR Section 12.2
Variances, VAR 12.2-3	Added reference to SSAR	Completeness
Variances, VAR 12.2-4	Revised variance	Consistency with FSAR Section 12.2
Variances, VAR 12.2-5	Added variance	DCD R9 gaseous effluent releases are not bounded by ESP
Variances, References	Added Reference 6	To include EIS
Exemptions	Changed title from “Exemption Requests” to “Exemptions”	Consistency with EF3 COLA

Revision 6 *(continued)*

Section	Changes	Reason for Change
Exemptions, Exemption 1	Added exemption for special nuclear material	Consistency with EF3 COLA
Exemptions, Exemption 2	Added exemption for intermediate switchyard	New exemption
Exemptions, Exemption 3	Added exemption request	New exemption
Exemptions, Table 3-1	Deleted Table 3-1	DCD R9
Exemptions, Exemption 4	Added exemption request	NAPS DEP 12.3-1

Revision 5

Section	Changes
All	Technology change from US-APWR to ESBWR

Revision 2

Section	Changes
Departures	Added Departure NAPS DEP 11.4-1 and associated justification.

Revision 1

Section	Changes
Departures	RAI 09.05.01-17, Fire Water Supply Locations
Variances	Revised to reflect issuance of ESP-003.
	Updated to align with DCD R5.
	RAI 12.02-1, Update to Commitment to Final Version of NEI 07-03
	RAI 12.02-10, Clarification of FSAR Tables in Chapter 12
	RAI 15.06.05-1, Dose Evaluation Factors
Exemption Requests	Deleted 10 CFR 26 Exemption Request.
	Added exemption for eliminating the expected minimum accumulator pressure value in the Bases for SR 3.1.5.1.
	Added exemption to revise the Bases description for SR 3.7.2.3 to include an expanded discussion of the acceptance criteria for differential pressure across the Emergency Filter Unit (EFU). [

Contents

Contents

DEPARTURES

Introduction

A *departure* is a plant-specific deviation from design information in a standard design certification rule. Departures from the reference ESBWR Design Control Document (DCD) are identified and evaluated consistent with regulatory requirements and guidance. Each departure is examined in accordance with 10 CFR 52 requirements. Although the ESBWR Design Certification Application is currently under review with the NRC, departures are evaluated utilizing the guidance provided in Regulatory Guide 1.206, Section C.IV.3.3.

It is anticipated that the final certification rulemaking for the ESBWR would have the same change process as that in current appendices to 10 CFR 52 and in the proposed 10 CFR 52 Appendix E, “Design Certification Rule for the ESBWR Design.” References in this part to the Design Certification Rule (DCR) or 10 CFR 52 Appendix E are understood to mean the proposed 10 CFR 52 Appendix E and the anticipated final ESBWR DCR.

The following departures are evaluated in this report:

NAPS DEP 3.7-1, Ground Response Spectra for Seismic Structural Loads and Floor Response Spectra

NAPS DEP 8.1-1: Figure 8.1-1, Sheet 1, *Electrical Power Distribution System*

NAPS DEP 8.1-2: Table 8.1-1, On-site Power System SRP Criteria Applicability Matrix

NAPS DEP 11.4-1: Long-term, Temporary Storage of Class B and C Low-Level Radioactive Waste

NAPS DEP 12.3-1: Liquid Radwaste Effluent Discharge Piping Flow Path

NAPS DEP 19A-1: Design of Structures Housing RTNSS Equipment for Hurricane Wind Generated Missiles

Departure: NAPS DEP 3.7-1, Ground Response Spectra for Seismic Structural Loads and Floor Response Spectra

1. Summary of Departure

DCD Table 2.0-1, *Envelope of ESBWR Standard Plant Site Parameters*, defines the safe shutdown earthquake (SSE) horizontal and vertical design ground response spectra of 5 percent damping, also termed the Certified Seismic Design Response Spectra (CSDRS), as the free-field outcrop spectra at the foundation level (bottom of the base slab) of the Reactor Building/Fuel Building and Control Building structures, as shown in DCD Figures 2.0-1 and 2.0-2. As specified in DCD Table 2.0-1, Note (9) for the Firewater Service Complex, which is essentially a surface founded structure, the CSDRS is 1.35 times the values shown in DCD Figures 2.0-1 and 2.0-2 and is defined as free-field outcrop spectra at the foundation level (bottom of the base slab) of the Firewater Service Complex structure. The site-specific horizontal and vertical seismic response spectra exhibit exceedances at certain frequencies, when compared to the CSDRS. As a result of these exceedances, Dominion performed site-specific soil-structure interaction (SSI) analyses for the RB/FB, CB and FWSC structures and revised the SSE definition to include the ESBWR CSDRS and the site-specific foundation input response spectra (FIRS) for each seismically qualified structure for use in performing seismic design, analysis, and qualification of structures, systems and components (SSCs).

Because the SSE is also defined in DCD Tier 1, Table 5.1-1, the changes to the site-specific definition requires a departure from DCD Tier 1 information. Therefore, a request for exemption from DCD Tier 1 information is provided in Exemption 3.

Finally, DCD Section 3.7 defines, as Tier 2* information, the ESBWR Operating Basis Earthquake (OBE) as one-third of the SSE ground motion. The Unit 3 plant-shutdown OBE response spectrum limit is based on (a) one-third of the CSDRS and (b) one-third of the site-dependent SSE manifestation at grade. Because all safety-related SSCs are designed, analyzed, and qualified to meet both the CSDRS and site-specific FIRS, plant shutdown is required, as discussed in FSAR Section 3.7.4.4, only if both response spectra in FSAR Section 3.7.4.4 are exceeded.

2. Scope/Extent of Departure

This departure is for the site-specific FIRS exceeding the CSDRS at certain frequencies and a revision of the SSE definition to include the site-specific FIRS for each seismically qualified structure. The changes are identified in FSAR Sections 1.3, 1.11, 2.0, 3.7, 3.8, 4.2, 9.1, 19.1, 19.2, and 19.5, and Appendices 3A, 3C, 3G, and 19A. The departure also involves redefinition of the OBE. The changes to the OBE definition are identified in FSAR Section 3.7.

As noted above, an associated request for exemption from DCD Tier 1 information is provided in Exemption 3.

3. Departure Justification

For the RB/FB and CB structures, DCD Table 2.0-1 defines the CSDRS associated with the SSE for horizontal and vertical directions as those presented in DCD Figures 2.0-1 and 2.0-2, respectively. For the FWSC, DCD Table 2.0-1, Note (9) defines the CSDRS. Comparisons of site-specific spectra with the CSDRS are presented in FSAR Figures 2.0-201, 2.0-202, 2.0-203, and 2.0-204 for both full column outcrop motions and geologic outcrop motions. In addition, FSAR Figure 3.7.1-285 presents the SSI input response spectra for the FWSC at the average elevation of the bottom of the concrete fill (Elevation 220 ft NAVD88, 220.86 ft NGVD 29) as further discussed in FSAR Section 3.7.1.1.4.2.3. As discussed in FSAR Section 3.7.1.1, these figures show that the site-dependent FIRS exceed the CSDRS for Seismic Category I structures. The site-specific SSI analyses results are presented in FSAR Section 3.7.2.4 for the RB/FB, CB and FWSC structures.

FSAR Figures 2.0-201, 2.0-202, 2.0-203, and 2.0-204 present the CSDRS and site-specific FIRS for the horizontal and vertical directions, for all of the Unit 3 Seismic Category I structures. These figures reflect the site-specific horizontal and vertical seismic spectra, therefore DCD Figures 2.0-1 and 2.0-2 for the RB/FB and CB structures and DCD Table 2.0-1, Note (9) for the FWSC structure, which defined the CSDRS, are not replaced by this departure. Seismic design, analyses, and qualification of site-specific structures, systems, and components use both the CSDRS and the site-specific FIRS for purposes of establishing the SSE ground motion response spectra, as defined in FSAR Section 3.7.1. This approach satisfies the minimum requirements for design ground motion as described in 10 CFR 50, Appendix S (as discussed in FSAR Section 3.7.1.1).

FSAR Section 3.7.2.4 and Appendix 3A discuss the site-specific SSI analyses that are performed to validate the design of the standard plant Seismic Category I structures, based on the site-specific SSI input motions. The results of the site-specific SSI and SSSI analyses, documented in FSAR Section 3.7.2.4 and Appendix 3A, demonstrate that the standard plant seismic design of structural members does not envelope the site-specific seismic responses for the RB/FB, CB and FWSC, in some instances. To address those instances where the standard design is not enveloping, structural evaluations are performed. For certain seismic equipment and supports, structural evaluations indicate that the standard design is not enveloping in all cases.

FSAR Section 3.7.2.8 states that the same process is used for the design and analyses of the Seismic Category II and Radwaste Building structures, including both the SSI analyses and the SSSI analyses, using the same methodology, load combinations, and acceptance criteria as used for the Seismic Category I structures.

FSAR Sections 19.1, 19.2, and 19.5, and Appendix 19A discuss the seismic risk evaluation. A site-specific Seismic Margin Analysis update is performed to evaluate the impact of the peak ground acceleration on the DCD PRA risk insights in support of a plant-specific PRA assessment, as described in these FSAR sections.

FSAR Section 3.7.2.4 refers to FSAR Appendix 3A where the site-specific floor response spectra for the best estimate, lower bound, and upper bound subsurface profiles are compared with the DCD enveloping floor response spectra at 5 percent damping. The analyses described in FSAR Appendix 3A indicate that the site-specific in-structure response spectra (ISRS), in some locations, exceed the DCD corresponding floor response spectra at 5 percent damping. The floor response spectra used for seismic design of systems and components consider the DCD floor response spectra and the site-specific ISRS.

The site-specific SSSI effects evaluations are performed using the same methodologies as used in the standard design using site-specific conditions, as described in FSAR Section 3A.17.11. In addition, SSSI analyses are performed of the CB-RB/FB combined models that include the Access Tunnel to evaluate the site-specific SSSI effects of RB/FB on the CB seismic response. This is not a change in the methodology but is a difference from the standard design to provide explicit representation of the site-specific conditions that exist between the RB/FB and the CB.

The seismic load demands are used in site-specific structural evaluations that are performed for those structures and components that are evaluated as part of the standard design. The site-specific structural evaluations are performed using the standard design methodologies, with the following changes related to the models and inputs:

- FSAR Section 3G.7.5.3, Stability Requirements (Reactor Building/Fuel Building (RB/FB)): The stability of the RB/FB is performed without considering the resistance from the shear keys, as in the standard design. No changes are made to the design and the shear keys remain a part of the RB/FB structure.
- FSAR Section 3G.7.5.2, Site Design Loads, Load Combinations, and Material Properties: The TRACG thermal loads, updated temperatures, and upper pool design changes described in DCD Section 3G.5 are evaluated for the standard design as separate calculations and with separate results provided in DCD Section 3G.5. The site-specific structural evaluations involving the TRACG thermal loads, updated temperatures, and upper pool design changes are performed in total using the updated global finite element model, which is used for the DCD Section 3G.5 calculations. The thermal loads for the RCCV are addressed using the SSDP-2D process (which is described in DCD Section 3G.1.5.4) for evaluating stresses in concrete and rebar for the structural evaluations as described in FSAR Section 3G.7.5.2. Rather than having two separate calculations, the site-specific structural evaluations combine these inputs, and the methodology described in DCD Section 3G.1.5.4. This is a change in (1) using the updated model (used for the DCD Section 3G.5 calculations), (2) thermal loads, and (3) the upper pool design for the structural evaluations. FSAR Section 3G.7.5.4.3.6 is a site-specific section that addresses the IC/PCCS Pools (Element 32 of the Reactor Building). This approach is acceptable because it is a global evaluation that considers the updated combined loads, and uses the conservative SSDP-2D method for reducing thermal loads for the RCCV.

The results of the evaluations of the structures, which are described in FSAR Appendix 3G, and equipment and components, which are described in FSAR Sections 3.8.2, 3G.7, 4.2, and 9.1, are compared to the acceptance limits. Changes that are necessary to ensure that the site-specific structures and equipment are seismically adequate are listed below by the FSAR section that describes the change.

- FSAR Section 3G.7.5.4.1, PCCS Condenser: The support saddle bolts and their embedment are changed to withstand the site-specific seismic loads.
- FSAR Section 3G.7.5.4.3, Structural Design Evaluation (Reactor Building): The arrangement of shear ties for Element 24211 in Section 23 at the exterior wall of the RB, Elevation 22.50 m to 24.60 m, is changed to withstand the site-specific seismic loads.

- FSAR Section 3G.8.5.4, Structural Design Evaluation (Control Building): For the CB, the size of steel girder SG23 (CBAR ID 21016) is changed from that used in the standard design to withstand the site-specific seismic loads.
- FSAR Section 3G.9.5.4, Structural Design Evaluation (Fuel Building): The arrangements of shear ties and reinforcement at the exterior wall at Elevations 4.65 m to 6.60 m are updated from standard design to withstand the site-specific seismic loads.
- FSAR Section 3G.10.5.4, Structural Design Evaluation (FWSC): Rebar is added to basemat Element 227 and rebar and shear ties are added to shear key Elements 72008 and 73017.
- FSAR Section 9.1.1, New Fuel Storage: For the new fuel storage racks in the buffer pool, the size of the anchor bolts is increased and the loads in the final embedment are increased to withstand the site-specific seismic loads.
- FSAR Section 9.1.2, Spent Fuel Storage: For the spent fuel storage racks in the buffer pool deep pit, the size of the anchor bolts is increased, the welds from the enveloping plate to the base plates are increased, and the loads in the final embedment are increased to withstand the site-specific seismic loads.
- Diaphragm Floor, described in FSAR Section 3G.7.5.4.2.1: A refined calculation has been performed applying the methodology consistent with the one used for development of the out-of-plane loads on slabs using equivalent average acceleration to demonstrate that the site-specific stress demands for the upper and lower radial plates remain within allowable limits.
- Acceptance Criteria, FSAR Section 3.8.4.5: The stress evaluation approach is modified for the RB and FB structures, as described in FSAR Section 3.8.4.5 using axial load-moment interaction curves to demonstrate that the ASME BPVC, Section III, Division 2, Subsection CC and ACI 349-01 acceptance criteria are met. The ASME acceptance criteria are based on a parabolic concrete stress-strain relationship and applicable ASME allowable stresses for a cross section subjected to membrane loads and moments due to factored loads. This refined approach is also described in FSAR Sections 3G.7.5.4 and 3G.9.5.4.

A plant-shutdown OBE response spectrum limit is established, as described in FSAR Section 3.7.1, for purposes of requiring a plant shutdown, as described in FSAR Section 3.7.4.4. The plant-shutdown OBE response spectrum limit is established based on one-third of the site-specific ground motion response spectra used in the design of seismic SSCs. This approach is consistent with 10 CFR 50, Appendix S, and Regulatory Guide 1.166, Section 4.1.2, for purposes of ensuring margin to the ground motion response spectra used in the design of seismic SSCs in the event of an earthquake.

4. Departure Evaluation

As discussed above, appropriate site-specific analyses for the RB/FB, CB, and FWSC structures have been conducted to assess site-specific FIRS exceeding the CSDRS at certain frequencies and a revision of the SSE definition to include the FIRS for each seismically qualified structure.

Specific changes from the standard design that result from the site-specific seismic analyses and structural evaluations are described in Section 3. This departure has been evaluated and determined to comply with the requirements of the ESBWR Design Certification Rule, Section VIII.

This departure involves a change to DCD Tier 1 and DCD Tier 2* information. Pursuant to Section VIII.B.2.b.5a of the ESBWR design certification rule, NRC approval is necessary; Exemption 3 requests the approval for the exemption from the DCD Tier 1 information.

Departure: NAPS DEP 8.1-1 - Figure 8.1-1, Sheet 1, *Electrical Power Distribution System*

1. Summary of Departure

DCD Tier 2, Figure 8.1-1, Sheet 1, *Electrical Power Distribution System*, has a horizontal dashed line with components in the “Turbine Island/Transformer Yard” shown below the line and components in the “Switchyard” shown above the line. This figure shows the location of the main generator circuit breaker and its motor-operated disconnects (MODs) below the dashed line in the “Turbine Island/Transformer Yard” area of the plant. The space available at the North Anna Power Station site for Unit 3 does not allow installing these components in this area of the plant. As shown in FSAR Figure 8.1-1R, an intermediate switchyard is needed for Unit 3 and the main generator circuit breaker and its MODs will be located in the intermediate switchyard. Therefore, the location of these components in the intermediate switchyard at Unit 3 represents a departure from DCD Tier 2 information. There are no changes to the functions performed by the main generator circuit breaker and its MODs, how the functions are performed, or the ability to perform the functions due to the change in location to the intermediate switchyard.

Also, because these components need to be located in the intermediate switchyard at Unit 3, the dashed line in DCD Tier 2, Figure 8.1-1, Sheet 1, needs to be used to clarify that the departure affects physical location but not functional performance. FSAR Figure 8.1-1R shows the addition of labels above and below the dashed line to indicate that there is not a departure from the functions performed by these components in the on-site power supply system of the ESBWR standard plant. Therefore, the addition of the labels represents a departure from DCD Tier 2 information.

Because the dashed line and the location of the main generator circuit breaker and its MODs are also defined in DCD Tier 1, Figure 2.13.1-1, Sheet 1, *Electric Power Distribution System Functional Arrangement*, adding the labels and locating these components in the intermediate switchyard also represent departures from DCD Tier 1 information. Therefore, a request for an exemption from DCD Tier 1 information is included in Exemption 2.

This Tier 2 departure does not pertain to the changes to DCD Tier 2, Figure 8.1-1, Sheet 1, to add the intermediate switchyard or to show a 500/230 kV intermediate transformer with high side circuit breaker and three MODs in the intermediate switchyard as part of the Unit 3 off-site power supply system in FSAR Figure 8.1-1R. For DCD Tier 2, the designs of the off-site power supply system and switchyard are required to be addressed in the FSAR by DCD Tier 2 COL Items. Changes to a DCD Tier 2 figure to address DCD COL Items do not require a departure.

2. Scope/Extent of Departure

This Tier 2 departure is for the location of the main generator circuit breaker and its MODs in the on-site power supply system and the addition of labels on both sides of the dashed line. These changes are shown in FSAR Figure 8.1-1R, Sheet 1. As noted above, an associated request for exemption from DCD Tier 1 information is provided.

3. Departure Justification

DCD Tier 2, Figure 8.1-1, Sheet 1, shows the overall electrical power distribution system including both the on-site and off-site power distribution systems. This figure has a horizontal dashed line with the “Turbine Island/Transformer Yard” below the line and the “Switchyard” above the line. This dashed line is nearly identical with the physical interfaces between the on-site power supply system and the off-site power supply system.

DCD Tier 2, Section 8.1.2.2, *Offsite Power System Description*, describes these physical interfaces more specifically as follows. This section states that the off-site power supply system includes the switchyard and the high voltage lines up to the high voltage side (high-side) MODs of the main generator circuit breaker, up to the high-side MODs of the circuit breakers for the unit auxiliary transformers, and up to the high-side MODs of the reserve auxiliary transformers.

Based on this description of the interface between the on-site and off-site power supply systems, the main generator circuit breaker and its MODs are part of the on-site power supply system and are included in the scope of the ESBWR standard plant design as described in the DCD. Per the DCD’s description, the main generator circuit breaker and its MODs are part of the on-site power supply system’s functional design. Per DCD Tier 2, Figure 8.1-1, these components are to be located in the area of the plant identified as the Turbine Island/Transformer Yard.

The space available for Unit 3 at the site does not allow the main generator circuit breaker and its MODs to be located in the Turbine Island/Transformer Yard area of the plant. Therefore, Unit 3 requires a departure from this DCD figure to locate the main generator circuit breaker and its MODs in the intermediate switchyard. To indicate that the main generator circuit breaker and its high-side MODs remain functionally in the on-site power supply system, the dashed line between “Turbine Island/Transformer Yard” and “Switchyard” is used inside of the intermediate switchyard to create two areas to clarify the departure affects location but not functional performance. The portion below the dashed line in the intermediate switchyard is labeled: “ESBWR standard plant.” The portion above the dashed line in the intermediate switchyard is labeled: “Unit 3 site-specific design.” These labels show that the departure is only related to the location of the main generator circuit breaker and its MODs, and does not affect the functions performed by these ESBWR standard plant components.

There are no proposed changes to the functions performed by the main generator circuit breaker and its MODs and no proposed changes to the method of operation. Because only the location of these components is being revised for this departure, there are no intended design functions, performance requirements, or DCD methods of evaluation that are affected by the proposed departure. The functional requirements for the main generator circuit breaker and its MODs that are established in the DCD for the on-site power supply system as part of the ESBWR standard plant design will continue to apply. Both the Turbine Island/Transformer Yard and the Intermediate Switchyard are outdoor locations. The main generator circuit breaker and its MODs are designed as outdoor equipment and are rated for the environmental conditions that are the same for both locations. There is no change to a design function, the ability to perform a design function, or the types of malfunctions identified for the main generator breaker and associated MODs as a result of the change in location. Therefore, the proposed departure does not have an adverse effect on an intended design function.

For DCD Tier 2, the design of the switchyard and off-site power supply system shown in DCD Tier 2, Figure 8.1-1, Sheet 1, is required to be added to the FSAR as indicated in DCD Tier 2 Section 8.2.1.1, *Transmission System*, see COL 8.2.4-1-A; and Section 8.2.1.2.1, *Switchyard*, see COL 8.2.4-2-A. Therefore, changes to the Tier 2 figure to add the intermediate switchyard and show a 500/230 kV intermediate transformer with high-side circuit breaker and three MODs in the intermediate switchyard as part of the Unit 3 off-site power supply system are not departures from DCD Tier 2 information.

4. Departure Evaluation

As described above, locating the main generator circuit breaker and its MODs in the intermediate switchyard and adding labels on each side of the dashed line in the intermediate switchyard drawing do not adversely affect any intended DCD design functions. This departure has been evaluated and determined to comply with the requirements of the Design Certification Rule, Section VIII.B.5.

Accordingly, this departure does not:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD;

2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the plant-specific DCD;

3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD;

4. Result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated in the plant-specific DCD;

5. Create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD;

6. Create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD;

7. Result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered; or

8. Result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses.

This departure does not affect resolution of an ex-vessel severe accident design feature identified in the DCD.

This departure does not modify design features and functional capabilities that are supported in a required assessment of a DCD design regarding aircraft impact hazards (i.e., as required by 10 CFR 50.150(a)(1)).

This departure involves a change to DCD Tier 1 information. Pursuant to Section VIII.B.2.b.5a of the ESBWR Design Certification Rule, NRC approval is necessary; Exemption 2 requests this approval.

Departure: NAPS DEP 8.1-2 – Table 8.1-1, Onsite Power System SRP Criteria Applicability Matrix

1. Summary of Departure

DCD Tier 2, Section 8.1.5.2.4 and Table 8.1-1, indicate that the off-site power system complies with Regulatory Guide (RG) 1.204. In RG 1.204, the NRC endorses four Institute of Electrical and Electronics Engineers (IEEE) documents that provide methods acceptable to the NRC for the design and implementation of lightning protection systems to ensure that electrical transients resulting from lightning phenomena do not render safety-related systems inoperable or cause spurious operation of such systems. The four IEEE documents are: IEEE Guide for Generating Station Grounding, Std. 665-1995 (reaffirmed 2001); IEEE Design Guide for Electrical Power Service Systems for Generating Stations, Std. 666-1991 (reaffirmed 1996); IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations, Std. 1050-1996; and IEEE Application Guide for Surge Protection of Electric Generating Plants, Std. C62.23-1995 (reaffirmed 2001).

The North Anna Power Station (NAPS) switchyard was designed and constructed in the 1970s in accordance with Dominion transmission system standards to serve up to four units at the NAPS site. North Anna Units 1 and 2 were placed on line in 1978 and 1980, respectively, and have been in continuous operation using the NAPS switchyard. The design and construction of the NAPS switchyard significantly predates the issue of RG 1.204 (initially issued as DG-1137, dated February 2005) and, as such, the NAPS switchyard design conforms to part, but not all, of RG 1.204. IEEE Stds. 665, 666, and 1050 provide design and installation practices relevant to the standard plant. IEEE Std. 665 also provides recommended practices for connecting the power plant grounding grid to the switchyard grounding grid. The NAPS switchyard grounding grid connection to the plant grid is consistent with IEEE Std. 665. The NAPS switchyard surge protection is designed to Dominion transmission system standards that provide similar protection, but do not specifically match all of the guidance provided in IEEE Std. C62.23. Therefore, a departure is needed from DCD Section 8.1.5.2.4 and Table 8.1-1 that indicates full compliance with RG 1.204 for the NAPS switchyard lightning protection system design.

2. Scope/Extent of Departure

This Tier 2 departure documents an exception to the requirements of RG 1.204 as it relates to the NAPS switchyard design for lighting/surge protection. These changes are shown in FSAR Section 8.1.5.2.4 an Table 8.1-1R. There is no associated departure for Tier 1. Section 2.13.9 and the ITAAC in Table 2.13.9-1 remain valid.

3. Departure Justification

The NAPS switchyard and its lightning protection system were designed and constructed in the 1970s, in accordance with Dominion transmission system standards, to serve up to four units at the NAPS site. North Anna Units 1 and 2 were placed on line in 1978 and 1980, respectively, and have been in continuous operation using the NAPS switchyard. The design and construction of the NAPS switchyard significantly predates the issue date of RG 1.204 (initially issued as DG-1137, dated February 2005) and, as such, the NAPS switchyard lightning protection system design conforms to part, but not all, of RG 1.204. IEEE Stds. 665, 666, and 1050 provide design and installation practices relevant to the standard plant. IEEE Std. 665 also provides recommended practices for connecting the power plant grounding grid to the switchyard grounding grid. The NAPS switchyard grounding grid connection to the plant grid is consistent with IEEE Std. 665. The NAPS switchyard conforms to IEEE Std. C62.23 with certain exceptions, and conforms to the corresponding NAPS switchyard surge protection design practices outlined in the Dominion transmission standards.

There are no proposed changes to the functions performed by the switchyard equipment or its surge protection, and no proposed changes to the method of operation. The off-site power system and switchyard are site-specific and meet the interface requirements specified for off-site power in the DCD; thus, there are no intended DCD design functions, DCD performance requirements, or DCD methods of evaluation that are affected by the proposed departure. The functional requirements for the off-site power system that are established in the DCD will continue to apply. There is no change to the types of malfunctions identified for the switchyard as a result of the exceptions to IEEE C62.23 for the surge protection. Therefore, the proposed departure does not have an adverse effect on an intended design function.

4. Departure Evaluation

This departure affects Tier 2 information.

As described above, deviations from the IEEE C62.23 guidance for switchyard surge protection does not adversely affect any DCD intended design functions. This departure has been evaluated and determined to comply with the requirements of the DCR, Section VIII.B.5.

Accordingly, this departure does not:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD;
2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the plant-specific DCD;
3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD;
4. Result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated in the plant-specific DCD;
5. Create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD;
6. Create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD;
7. Result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered; or
8. Result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses.

This departure does not affect resolution of an ex-vessel severe accident design feature identified in the DCD.

This departure does not modify design features and functional capabilities that are supported in a required assessment of a DCD design regarding aircraft impact hazards (i.e., as required by 10 CFR 50.150(a)(1)).

Therefore, in accordance with RG 1.206, Section C.IV.3.3, and the DCR, Section VIII.B.5, this departure does not require prior NRC approval or an exemption from 10 CFR 52.

Departure: NAPS DEP 11.4-1 - Long-Term, Temporary Storage of Class B and C Low-Level Radioactive Waste

1. Summary of Departure

The ESBWR DCD identifies that on-site storage space for a six-month volume of packaged waste is provided in the Radwaste Building. The Unit 3 Radwaste Building is configured to accommodate a minimum of ten years volume of packaged Class B and C waste, while maintaining space for at least three months of packaged Class A waste. This departure reconfigures the arrangement of systems and components within the ESBWR Radwaste Building volume. The systems, structures, and components requiring re-arrangement are associated with the Liquid Waste Management System and Solid Waste Management System (SWMS). The existing Radwaste Building Fire Protection and HVAC Systems have sufficient capacity to accommodate the extra volume of Class B and C wastes, and require no modification.

2. Scope/Extent of Departure

This departure affects Tier 2 information in the ESBWR DCD. The departure from the Tier 2 information does not involve a change to or departure from Tier 1 information, Tier 2* information, operational requirements, or the Technical Specifications. This departure is identified in FSAR Sections 1.2.2.10.2, 1.2.2.16.9, 11.4, 11.4.1, 11.4.2.2.1, 11.4.2.2.2, 11.4.2.2.4, 11.4.2.3.1, 12.2 and 12.3; FSAR Tables 1.9-11R, 9A.5-5R, 11.4-1R, 11.4-2R, 12.2-22R, and 12.3-8R; and FSAR Figures 1.2-21R, 1.2-22R, 1.2-23R, 1.2-24R, 1.2-25R, 9A.2-20R, 9A.2-21R, 9A.2-22R, 9A.2-23R, 9A.2-24R, 11.4-1R, 11.4-2R, 12.3-19R, 12.3-20R, 12.3-21R, 12.3-22R, 12.3-39R, 12.3-40R, 12.3-41R, 12.3-42R, 12.3-61R, 12.3-62R, 12.3-63R, and 12.3-64R.

3. Departure Justification

DCD Sections 11.4.1, SWMS Design Basis, and 11.4.2.2.4, Container Storage Subsystem, discuss on-site storage space for low-level radioactive waste. The design accommodates a six-month volume of packaged waste storage in the Radwaste Building.

Class A, B, and C low-level radioactive waste is normally promptly disposed of at licensed off-site processing and disposal facilities. In the event that an off-site facility is not available to accept Class B and C waste shipments, the Unit 3 Radwaste Building waste storage space has been configured to accommodate at least ten years of Class B and C waste generated during plant operation. Shielding analysis results show that the dose rates in surrounding areas, both within the building and externally, are maintained below the allowable limits in accordance with the radiological area classification in FSAR Section 12.3. Long-term, temporary storage of Class B and C waste HICs, with design lifetimes of 300 years, will not have an adverse effect on the integrity of the waste containers. Periodic inspections will be performed to confirm container integrity during storage.

The increased Class B and C waste storage space is consistent with the regulatory guidance of NUREG-0800, Section 11.4, Appendix 11.4-A. The storage space reserved for Class A waste exceeds that recommended by NUREG-0800, Standard Review Plan, Branch Technical Position 11-3.

4. Departure Evaluation

This departure affects DCD Tier 2 information.

This Tier 2 departure does not affect off-site dose rates or the integrity of waste containers in storage. As such, the potential for increased radiation exposure to members of the public is not created. Accordingly, it does not:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD;
2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the plant-specific DCD;
3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD;
4. Result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated in the plant-specific DCD;
5. Create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD;
6. Create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD;
7. Result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered; or
8. Result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses.

This departure does not affect resolution of an ex-vessel severe accident design feature identified in the ESBWR DCD.

This departure does not modify design features and functional capabilities that are supported in a required assessment of a DCD design regarding aircraft impact hazards (i.e., as required by 10 CFR 50.150(a)(1)).

Therefore, in accordance with RG 1.206, Section C.IV.3.3, and the DCR, this departure does not require prior NRC approval or an exemption from 10 CFR 52.

Departure: NAPS DEP 12.3-1 - Liquid Radwaste Effluent Discharge Piping Flow Path

1. Summary of Departure

The DCD describes that the Liquid Waste Management System (LWMS) either returns processed water to the condensate system or discharges to the environment via the circulating water system. The DCD also describes that the portion of the circulating water system which receives the LWMS discharge is the cooling tower blowdown line. For Unit 3, the discharges from the LWMS to the environment will use only the liquid radioactive waste effluent discharge pipeline and not the cooling tower blowdown line. This departure will simplify design and construction of the cooling tower blowdown line.

The change to not use the cooling tower blowdown line for transfer of liquid radwaste effluent means that a departure is needed from certain DCD Tier 2 information. Also, because DCD Tier 1 describes the use of the circulating water system for discharge of LWMS effluent, a request for an exemption from DCD Tier 1 information is included in Exemption 4.

2. Scope/Extent of Departure

This Tier 2 departure is for not using the cooling tower blowdown line in the circulating water system as part of the flow path for liquid radwaste effluent discharges to the environment. The Unit 3 flow path is limited to the liquid radwaste effluent discharge pipeline between the Radwaste Building and the environment. The changes needed in DCD Tier 2 Chapters 11 and 12 are contained in the following FSAR sections, figure and table.

DCD Section 11.2.3.2, *Design Description*, describes that all radioactive releases will be discharged to the circulating water system. This departure changes the sentence in FSAR Section 11.2.3.2 to: “Liquid radioactive releases will be discharged using the liquid radwaste effluent discharge pipeline.”

DCD Figure 11.2-1b, *Floor Drain*, identifies that the “Floor Drain Process Subsystem” has a LWMS effluent discharge flow path labeled: “DISCHARGE VIA RADIATION MONITOR TO CIRCULATING WATER.” This departure changes the label in FSAR Figure 11.2-1bR to: “DISCHARGE VIA RADIATION MONITOR TO LIQUID RADWASTE EFFLUENT DISCHARGE PIPELINE.”

DCD Section 12.3.1.5.1, *Design Considerations*, indicates the “Cooling Tower Blowdown Line” is one of four piping segments that will contain radioactive materials, will have to run underground, and will be designed to preclude inadvertent or unidentified leakage to the environment. These piping segments are enclosed within a guard pipe and monitored for leakage, or are accessible for visual inspections via a trench or tunnel. This departure deletes the “Cooling Tower Blowdown Line” from the list because the liquid “Radwaste Effluent Discharge Pipeline” (as shown on the list) will no longer be directed to the cooling tower blowdown line. The cooling tower blowdown line will therefore not contain liquid radwaste effluent and will not need to be designed with these special features, which simplifies the design.

DCD Table 12.3-18, *Regulatory Guide 4.21 Design Objective and Applicable DCD Subsection Information*, Design Objective 3, identifies DCD Section 11.2.3.2 as a section which includes a description of a design feature used to meet the objective. This table repeats the sentence from that DCD section describing that all radioactive releases will be discharged to the circulating water system. This departure changes the sentence in FSAR Table 12.3-18R to: “Liquid radioactive releases will be discharged using the liquid radwaste effluent discharge pipeline.”

As noted above, an associated request for exemption from DCD Tier 1 information is provided.

3. Departure Justification

For the affected DCD Tier 2 sections, figure, and table listed above, the intended function of the circulating water system, and specifically the cooling tower blowdown line in the system, is to be a portion of the discharge path from the LWMS in the Radwaste Building to the environment. The liquid radwaste effluent discharge pipeline in the LWMS was to be discharged to the cooling tower blowdown line which would in turn discharge to the environment. For a COL Applicant, the DCD was intending that the cooling tower blowdown line be treated as containing liquid radwaste. To perform the function of containing the liquid radwaste with the performance requirement to not allow inadvertent or unidentified leakage to the environment, the cooling tower blowdown line was to be either enclosed within a guard pipe and monitored for leakage, or made accessible for visual inspections via a trench or tunnel.

The change is to not use the cooling tower blowdown line to transfer radwaste effluent to the environment and to extend the liquid radwaste effluent discharge pipeline to transfer liquid radwaste from the LWMS in the Radwaste Building to the environment. This change involves pipelines that are required to comply with regulations at 10 CFR 20.1406 to minimize, to the extent practicable, contamination of the facility and the environment.

With the departure, the cooling tower blowdown line will not be used to contain liquid radwaste and so the special design requirements for performing that function will not be required for the Unit 3 cooling tower blowdown line. This change does not have an adverse effect on a DCD-described design function because the liquid radwaste effluent discharge pipeline in the LWMS will be extended to transfer liquid radwaste from the Radwaste Building to the environment and that pipeline continues to meet the special design requirements and the regulations. The underground segments of the liquid radwaste effluent discharge pipeline will either be enclosed within a guard pipe and monitored for leakage, or made accessible for visual inspections via a trench or tunnel.

The change for this departure to use only the liquid radwaste effluent discharge pipeline for transfer to the environment will mean that the Unit 3 design continues to meet the DCD requirement for the piping to comply with 10 CFR 20.1406.

4. Departure Evaluation

As described above, not using the cooling tower blowdown line for transfer of liquid radwaste effluent discharges and extending the liquid radwaste effluent discharge pipeline to transfer liquid radwaste from the Radwaste Building to the environment do not adversely affect any intended DCD design functions. This departure has been evaluated and determined to comply with the requirements of the Design Certification Rule, Section VIII.B.5.

Accordingly, this departure does not:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD;
2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the plant-specific DCD;
3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD;
4. Result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated in the plant-specific DCD;
5. Create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD;
6. Create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD;
7. Result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered; or
8. Result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses.

This departure does not affect resolution of an ex-vessel severe accident design feature identified in the DCD.

This departure does not modify design features and functional capabilities that are supported in a required assessment of a DCD design regarding aircraft impact hazards (i.e., as required by 10 CFR 50.150(a)(1)).

This departure involves a change to DCD Tier 1 information. Pursuant to Section VIII.B.2.b.5a of the ESBWR Design Certification Rule, NRC approval is necessary; Exemption 4 requests this approval.

Departure: NAPS 19A-1, Design of Structures Housing RTNSS Equipment for Hurricane Wind Generated Missiles

1. Summary of Departure

DCD Appendix 19A, Regulatory Treatment of Non-Safety Systems, defines the design requirements for SSCs that are subject to Regulatory Treatment of Non-Safety Systems (RTNSS). DCD Section 19A.8.3, Augmented Design Standards, addresses the design requirements for structures housing RTNSS SSCs for resisting the impacts of missiles generated by hurricane winds. Subsequent to GEH's submittal of the Design Certificate Application for the ESBWR, the NRC issued revised guidance specifying maximum hurricane winds and the size and velocity of hurricane wind generated missiles that should be considered in the design of structures housing RTNSS SSCs. RG 1.221, Design-Basis Hurricane and Hurricane Missiles for Nuclear Power Plants, issued October 2011, contains the current NRC guidance for defining maximum hurricane winds and hurricane wind generated missile parameters.

The maximum hurricane wind for the Unit 3 site location specified in RG 1.221 is bounded by the maximum hurricane wind specified in the ESBWR DCD. The revised NRC guidance in RG 1.221, however, results in slightly higher velocities for certain hurricane wind generated missiles. This departure adds requirements to address higher Unit 3 site-specific hurricane wind generated missile velocities where the site-specific missile parameters are more severe than those specified in the DCD.

FSAR Table 2.2-201, Evaluation of Site/Design Parameters and Characteristics, contains, as Tier 2* information, references to hurricane wind generated missile parameters.

Because hurricane wind generated missiles used in the design of structures housing RTNSS SSCs are also addressed in DCD Tier 1, Table 5.1-1, Envelope of ESBWR Standard Plant Site Parameters, the additional design requirements for the Unit 3 site-specific hurricane wind generated missiles requires a departure from DCD Tier 1 information. Therefore, a request for exemption from DCD Tier 1 information is provided in Exemption 5.

2. Scope and Extent of Departure

This departure adds requirements to address Unit 3 site-specific hurricane wind generated missiles in accordance with RG 1.221. The changes are identified in FSAR Section 2.0 and Appendix 19A.

As noted above, an associated request for exemption from DCD Tier 1 information is provided in Exemption 5.

3. Departure Justification

DCD Appendix 19A defines the design requirements for structures housing RTNSS SSCs for resisting the impacts of hurricane wind generated missiles. The maximum hurricane wind speed for the Unit 3 site is lower than the maximum hurricane wind speed specified in the DCD. However, the current NRC guidance in RG 1.221 results in slightly higher hurricane wind generated missile velocities than those specified in the DCD for missiles of similar mass. This departure adds requirements to address the site-specific hurricane wind generated missile velocities when the site specific missile parameters exceed those specified in the DCD. The design of Unit 3 structures housing RTNSS SSCs continues to comply with the hurricane wind generated missile parameters specified in the DCD when the specified missile parameters are more conservative than the Unit 3 site-specific missile parameters.

4. Departure Evaluation

As discussed above, this departure adds requirements to address Unit 3 site-specific hurricane wind generated missiles calculated in accordance with current NRC guidance in RG 1.221 where the site-specific missile parameters exceed those specified in the DCD. The design of structures housing RTNSS SSCs continues to comply with the hurricane wind generated missiles where the parameters specified in the DCD exceed the Unit 3 site-specific missile parameters specified in accordance with RG 1.221.

This departure has been evaluated and determined to comply with the requirements of the Design Certification Rule, Section VIII.B.5.

Accordingly, this departure does not:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD;
2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the plant-specific DCD;
3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD;
4. Result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated in the plant-specific DCD;
5. Create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD;
6. Create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD;

7. Result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered; or

8. Result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses.

This departure does not affect resolution of an ex-vessel severe accident design feature identified in the DCD.

This departure does not modify design features and functional capabilities that are supported in a required assessment of a DCD design regarding aircraft impact hazards (i.e., as required by 10 CFR 50.150(a)(1)).

This departure involves a change to DCD Tier 1 and DCD Tier 2* information. Pursuant to Section VIII.B.2.b.5a of the ESBWR design certification rule, NRC approval is necessary; Exemption 5 requests the approval for the exemption from the DCD Tier 1 information.

VARIANCES

Introduction

A *variance* is a plant-specific deviation from one or more of the site characteristics, design parameters, or terms and conditions of an ESP or from the site safety analysis report (SSAR). A variance to an ESP is analogous to a departure from a standard design certification.

The following sections provide requests for variances from the site characteristics for the North Anna ESP (Reference 1) and from the ESPA SSAR. The requests comply with the requirements of 10 CFR 52.39 and 10 CFR 52.93. To support a decision whether to grant a variance, each variance request provides the technical justification and supporting cross-references to the Unit 3 FSAR information that meet the technically relevant regulatory acceptance criteria.

This COLA complies with the requirements of 10 CFR 52.79, *Contents of Applications; Technical Information in Final Safety Analysis Report*, and 10 CFR 52.39, *Finality of Early Site Permit Determinations*. In accordance with 10 CFR 52.79(b)(2) and 10 CFR 52.39(d), this COLA requests a variance where the Unit 3 FSAR references the North Anna ESP and: a) the Unit 3 FSAR does not demonstrate that the design of Unit 3 falls within the ESP site characteristics; or b) the Unit 3 FSAR does not demonstrate that the design of Unit 3 falls within the ESP (design) controlling parameters; or c) the Unit 3 FSAR does not incorporate the ESP SSAR information by reference without the need for certain changes. Accordingly, this COLA includes the following requests for variances:

NAPS ESP VAR 2.0-1 - Long-Term Dispersion Estimates (χ/Q and D/Q)
NAPS ESP VAR 2.0-2 - Hydraulic Conductivity
NAPS ESP VAR 2.0-3 - Hydraulic Gradient
NAPS ESP VAR 2.0-4 - Vibratory Ground Motion
NAPS ESP VAR 2.0-5 - Distribution Coefficients (K_d)
NAPS ESP VAR 2.0-6 - DBA Source Term Parameters and Doses
NAPS ESP VAR 2.0-7 - Coordinates and Abandoned Mat Foundations
NAPS ESP VAR 2.3-1 - Tornado Site Characteristics
NAPS ESP VAR 2.4-1 - Void Ratio, Porosity, and Seepage Velocity
NAPS ESP VAR 2.4-2 - NAPS Water Supply Well Information
NAPS ESP VAR 2.4-3 - Well Reference Point Elevation
NAPS ESP VAR 2.4.4 - Lake Level Increase
NAPS ESP VAR 2.4-5 - Lake Anna PMF Level Increase
NAPS ESP VAR 2.5-1 - Stability of Slopes
NAPS ESP VAR 2.5-2 - [Deleted]
NAPS ESP VAR 12.2-1 - Gaseous Pathway Doses
NAPS ESP VAR 12.2-2 - [Deleted]

NAPS ESP VAR 12.2-3 - Annual Liquid Effluent Releases
NAPS ESP VAR 12.2-4 - Existing Units' Doses
NAPS ESP VAR 12.2-5 - Annual Gaseous Effluent Releases

Variance: NAPS ESP VAR 2.0-1 – Long-Term Dispersion Estimates (χ/Q and D/Q)

Request

This is a request to use the Unit 3 maximum long-term dispersion estimates (χ/Q and D/Q) values provided in FSAR Table 2.3-16R for types of locations other than the EAB rather than the corresponding ESP values in FSER Supplement 1, Appendix A and in SSAR Table 2.3-16. The Unit 3 values for the Radwaste Building ventilation stack do not fall within (are greater than) the ESP and SSAR values.

This variance results from a review of the Radiological Environmental Monitoring Program (FSAR Reference 2.3-201). The review and subsequent plotting of updated receptor locations using Geographic Information System (GIS) technology determined that since the time of the SSAR, locations of and distances to several of the "closest receptors" had changed. The χ/Q and D/Q evaluation, and the subsequent normal gaseous effluent dose evaluation, conservatively assumed that each receptor (meat animal, vegetable garden, residence) is at the distance of that closest receptor and in the true East-southeast direction, which is the direction of the maximum annual χ/Q value at that distance.

Justification

This variance is acceptable because all estimated annual doses from normal gaseous effluent releases remain within applicable limits as shown in FSAR Table 12.2-201.

Because of the changes in Unit 3 maximum long-term dispersion and deposition estimates, and also because of changes in maximum annual gaseous release values, some of the gaseous effluent doses are higher than the corresponding ESP value. See related variance NAPS ESP VAR 12.2-1, which is addressed below.

Variance: NAPS ESP VAR 2.0-2 – Hydraulic Conductivity

Request

This is a request to use the Unit 3 maximum hydraulic conductivity value provided in FSAR Section 2.4.12.1.2 rather than the corresponding ESP value in FSER Supplement 1, Appendix A and in SSAR Table 1.9-1. The Unit 3 value does not fall within (is larger than) the ESP and SSAR value.

The ESP value of 1.04 m/day (3.4 ft/day) represents the upper limit of the values obtained by in situ hydraulic conductivity testing of observation wells installed for the ESP subsurface investigation.

These values varied from 0.076 to 1.04 m/day (0.25 to 3.4 ft/day) as shown in SSAR Table 2.4-16. The corresponding maximum hydraulic conductivity value reported in FSAR Section 2.4.12.1.2 is 3.0 m/day (9.9 ft/day) based on an expanded range from 0.076 to 3.0 m/day (0.25 to 9.9 ft/day). This data set includes in situ hydraulic conductivity test results for the observation wells installed for the ESP subsurface investigation plus additional observation wells installed for the Unit 3 subsurface investigation. Unit 3 values provided in FSAR Section 2.4.12.1.2 associated with hydraulic conductivity that do not fall within (are larger than) the ESP/SSAR values are as follows:

Value	ESP/SSAR Value	Unit 3 Value
Maximum – Saprolite	3.4 ft/day	9.9 ft/day
Geometric mean – Saprolite	1.3 ft/day	1.74 ft/day
Maximum – Bedrock	3 ft/day	6.3 ft/day

The variance in hydraulic conductivity values results from the hydraulic conductivity testing of the additional observation wells installed for the Unit 3 subsurface investigation.

Justification

The variance in hydraulic conductivity values is acceptable because:

1. Compliance with 10 CFR 20 is demonstrated in FSAR Section 2.4.13 with the use of a hydraulic conductivity value of 9.9 ft/day to evaluate radionuclide concentrations and associated doses resulting from a postulated accidental release of liquid effluents in the groundwater pathways. The calculated radionuclide concentrations and associated doses are conservative as the hydraulic conductivity of 9.9 ft/day is the maximum value identified in FSAR Table 2.4-16R.

2. The groundwater flow model used to evaluate the maximum groundwater level elevation at the Unit 3 site incorporated the hydraulic conductivity values measured for the Unit 3 subsurface investigation. The maximum groundwater level elevation in the power block area is predicted to range from approximately 270 to 284 ft NAVD88 (270.86 to 284.86 ft NGVD29). The maximum groundwater level elevation in the power block area around Seismic Category I structures is approximately 282.6 ft NAVD88 (283.46 ft NGVD29) or 7.4 ft below the design plant grade elevation of 290 ft NAVD88 (290.86 ft NGVD29). As shown in FSAR Table 2.0-201, this Unit 3 site characteristic value for maximum groundwater level elevation falls within the DCD site parameter value in DCD Table 2.0-1. The ESBWR design assumes a maximum groundwater level no higher than 0.61 m (2 ft) below the design plant grade elevation at a site and the Unit 3 site characteristic value of 7.4 ft below the Unit 3 design plant grade meets this requirement.

Variance: NAPS ESP VAR 2.0-3 – Hydraulic Gradient

Request

This is a request to use the Unit 3 hydraulic gradient value provided in FSAR Section 2.4.12.1.2 rather than the corresponding ESP value in FSER Supplement 1, Appendix A and in SSAR Table 1.9-1. The Unit 3 value does not fall within (is larger than) the ESP and SSAR value.

SSAR Section 2.4.12.1.2 states that there is a hydraulic gradient toward Lake Anna of about 3 ft per 100 ft. The corresponding Unit 3 hydraulic gradient in FSAR Section 2.4.12.1.2 is calculated to be 5 ft per 100 ft.

The variance in hydraulic gradient results from the use of additional groundwater data collected from the Unit 3 subsurface investigation.

Justification

The variance in hydraulic gradient is acceptable because compliance with 10 CFR 20 is demonstrated in FSAR Section 2.4.13 with the use of the higher hydraulic gradient of 5 ft per 100 ft to evaluate radionuclide concentrations and associated doses as a result of a postulated accidental release of liquid effluents in the groundwater pathways.

Variance: NAPS ESP VAR 2.0-4 – Vibratory Ground Motion

Request

This is a request to use the Unit 3 horizontal and vertical spectral acceleration (g) values for the ground motion response spectra (GMRS) at the top of a hypothetical outcrop under the reactor building/fuel building (RB/FB) common foundation (Elevation 224 ft NAVD88 (224.86 ft NGVD29)), rather than hypothetical outcrop control point safe shutdown earthquake (SSE) spectrum at the top of Zone III-IV (Elevation 249.14 ft NAVD88 (250 ft NGVD29)), as presented in the ESP and SSAR. The Unit 3 values do not fall within (are larger than) the ESP and SSAR values at some frequencies.

The Unit 3 GMRS horizontal and vertical spectra at Elevation 224 ft NAVD88 (224.86 ft NGVD29) are plotted in FSAR Figure 2.5.2-313. The corresponding ESP spectra at Elevation 249.14 ft NAVD88 (250 ft NGVD29) are provided in ESP FSER NUREG-1835, Supplement 1, Appendix A, Figure 2, and in SSAR Figure 2.5-48A. FSAR Figure 2.0-206 and Table 2.0-202 compare the Unit 3 and ESP horizontal response spectra. FSAR Figure 2.0-207 and Table 2.0-203 compare the Unit 3 and ESP vertical response spectra. There are 38 frequencies used for the Unit 3 spectra, however, the comparison with the ESP spectra is shown for the 21 frequencies which were used for the ESP spectra.

Besides the difference in elevation at which the SSE and GMRS are defined in the SSAR and FSAR, there are additional differences in models, data, and methodologies that contribute to the differences of the resulting SSE and GMRS.

A significant change in the FSAR is the replacement of the starting EPRI-SOG models and databases used in the SSAR (SSAR Section 2.5 References 1, 115, 120, and 121) by the starting models and databases of the Central and Eastern US Seismic Source Characterization (CEUS SSC) report by EPRI et al. (FSAR Reference 2.5-223). The new CEUS SSC models and databases included a new earthquake catalog, different characterization of the seismic sources, and state-of-the-knowledge evaluation of maximum magnitudes.

Unlike the EPRI-SOG earthquake catalog, the CEUS SSC earthquake catalog does not include a specific tabulation of Modified Mercalli intensities (MMI). Measures of MMI were considered in the development of the CEUS SSC earthquake catalog in estimating a uniform measure of magnitude; however, their exclusion in the final catalog tabulation is reflected in the earthquake tabulation in FSAR Table 2.5.2-202.

While the EPRI (2004) model of prediction equations for median ground motions and their aleatory uncertainties (FSAR Reference 2.5-224) was used in the PSHA for the SSAR, the EPRI (2013) model of prediction equations for median ground motions and their aleatory uncertainties (FSAR Reference 2.5-407) was used in the PSHA for the FSAR.

The procedures by which the rock ground motions are developed and used as input to the site response analyses in the SSAR and FSAR are different in two notable ways because the FSAR follows RG 1.208; the SSAR was based on earlier guidance. First, in the SSAR, the hard rock SSE was developed as a hybrid envelope of two methods: a modified reference probability approach from then-active RG 1.165 and a "pre-RG 1.208" performance-based approach. In the FSAR, only the published RG 1.208 performance-based approach was used. Second, in the SSAR, the rock motions used for input to the site response were high frequency (HF) and low frequency (LF) components of the hard rock SSE. In the FSAR, the performance-based methodology in RG 1.208 was applied not to rock motions (as in the SSAR), but to the GMRS-horizon motions resulting from the site response analyses. That is, for the FSAR, the HF and LF rock motions corresponding to uniform hazard response spectra (UHRS) at mean annual frequencies (MAFE) of 10^{-4} and 10^{-5} were used as rock motion inputs to the site response analyses, resulting in GMRS-horizon UHRS at MAFEs of 10^{-4} and 10^{-5}. The RG 1.208 performance-based methodology is then applied to the GMRS-horizon UHRS to obtain the GMRS ground motions. Another input to the site response analyses was the additional FSAR data from the Unit 3 subsurface investigation, which provided the seismic wave transmission characteristics of the materials specifically applied to the Unit 3 Seismic Category I RB/FB.

In the FSAR's development of the Unit 3 horizontal spectral acceleration (g) values for the GMRS at a hypothetical outcrop at Elevation 224 ft NAVD88 (224.86 ft NGVD29), the site response analysis program P-SHAKE was used, rather than SHAKE2000, which was used in the SSAR evaluations. Operating exclusively in the frequency domain, P-SHAKE uses power spectral density functions derived from input rock response spectra, in lieu of earthquake time histories matched to those same rock response spectra, and then used as input to SHAKE2000, as was the approach used in the SSAR analysis. Simulating the effect of numerous input spectrally-matched time histories, the methodology used in P-SHAKE derives a more robust consideration of the variability of input ground motions. The resulting smooth output ground motions from P-SHAKE do not require a post-process fitting function, as was used to smooth the ground motions for the top of Zone III-IV SSE in the SSAR analysis.

In the SSAR, the subsurface soil/rock column characterization was represented by 50 simulated profiles, while for the FSAR, 60 simulated profiles were used.

This variance also includes moving the definition of the operating basis earthquake (OBE) from SSAR Section 2.5.2 to FSAR Section 3.7 in order to facilitate compatibility with OBE instrumentation that records free-field ground motions at grade.

Justification

The variance in the GMRS control point location is justified because its location at a hypothetical outcrop under the RB/FB foundation is representative of the Unit 3 site below the foundations for the Seismic Category I structures in the power block area. This location is also consistent with NUREG-0800, SRP 2.5.2, which specifies that the GMRS be defined on an outcrop or a hypothetical outcrop that will exist after excavation.

The variance in the horizontal and vertical spectral acceleration values results from and is justified not only by the change in control point location but also from application of updated methodology and data, consistent with current NRC guidance. The GMRS was derived using the performance-based approach endorsed in RG 1.208, and the new CEUS SSC models and databases. To evaluate the potential significance of any reinterpretation of past earthquakes and to consider the impact of more recent seismicity, including the 2011 **M** 5.8 Mineral, Virginia earthquake, the CEUS SSC earthquake catalog was reviewed and updated for the period 2009 through mid-December 2011. Therefore, by using RG 1.208 and updating the CEUS, the Unit 3 GMRS is acceptable.

EPRI (2013) reviewed the model of prediction equations for median ground motions given in EPRI (2004) and the subsequently updated aleatory uncertainties given in EPRI (2006) (FSAR Reference 2.5-225). EPRI (2013), which presented an updated version of the EPRI (2004, 2006) ground motion models, was endorsed by the NRC (2013) (FSAR Reference 2.5-408) as an “acceptable ground motion attenuation model for use by CEUS plants in developing plant-specific ground motion response spectra until such time as the NGA-East project is completed and has been reviewed and approved by NRC staff.” As of mid-2014, the NGA-East project, which is a SSHAC Level 3 study on a new CEUS ground motion model, has not been completed.

The number of frequencies was increased to 38 frequencies based on the minimum number of points specified in RG 1.206 and RG 1.208. The SSAR, which presents 21 points, was written before these documents were issued. Therefore, the FSAR was updated to conform to the existing guidance.

The specification of OBE in SSAR Section 2.5.2.7 is moved to FSAR Section 3.7 because neither SRP 2.5.2 nor the DCD requests the OBE information to be described in FSAR Section 2.5.2. Further, given that OBE instrumentation is likely to be at a surface location, the definition of the OBE ground motions should consider the site response of multiple possible surface or at grade locations, which is not assessed in FSAR Section 2.5.2, but is in FSAR Section 3.7. Therefore, the OBE is defined in FSAR Section 3.7.

Variance: NAPS ESP VAR 2.0-5 – Distribution Coefficients (K_d)

Request

This is a request to use the Unit 3 distribution coefficient (K_d) values provided in FSAR Table 2.4-206 rather than the corresponding values in SSAR Table 1.9-1 and SSAR Table 2.4-20. Some of the values provided in FSAR Table 2.4-206 do not fall within (are smaller than) the SSAR values and therefore would predict higher doses than the K_d values in the SSAR.

A variance for several K_d values results from using the minimum site-specific K_d values from FSAR Table 2.4-207 for estimating the radionuclide migration to surface waters via groundwater pathways. The SSAR K_d values were assigned using literature values. The measured Unit 3 K_d values were obtained by laboratory testing and are provided in FSAR Table 2.4-207.

Justification

The variance in K_d values is acceptable because compliance with 10 CFR 20 is demonstrated in FSAR Section 2.4.13 with the use of the minimum site-specific K_d values to evaluate radionuclide concentrations and associated doses as a result of a postulated accident release of liquid effluents in the groundwater pathways.

Variance: NAPS ESP VAR 2.0-6 – DBA Source Term Parameters and Doses

Request

This is a request to use the Unit 3 source terms and resulting doses from DCD Chapter 15 analyses of design basis accidents (DBAs). DCD Chapter 15 provides the required analyses of design basis accidents for the ESBWR. The DCD Chapter 15 source terms replace the ESBWR accident source terms in ESP-003, Appendix B, and in SSAR Chapter 15. The DCD Chapter 15 doses replace the ESBWR DBA doses in SSAR Chapter 15.

10 CFR 52.17(a)(1) required that the SSAR demonstrate the acceptability of the ESP site under the radiological consequences evaluation factors identified in 10 CFR 50.34(a)(1) and that site characteristics comply with 10 CFR 100. Specifically, 10 CFR 100.21(c)(2) requires that radiological dose consequences of postulated accidents meet the criteria set forth in 10 CFR 50.34(a)(1). Therefore, SSAR Chapter 15 analyzed a set of postulated accidents to demonstrate that a reactor or reactors bounded by parameters defined therein could be operated on the ESP site without undue risk to the health and safety of the public. Accident analyses evaluated in SSAR Chapter 15 were based on accidents and associated source terms for a range of possible reactor designs, including the AP1000, ABWR, and the ESBWR plant designs. Based on these analyses, the DBA source term parameters were established for the site in ESP-003, Appendix B.

A comparison of DBA source terms evaluated for the ESBWR in DCD Chapter 15 shows that they are not bounded by the ESP-003 source terms in all cases. Some Unit 3 values do not fall within (are larger than) the ESP and SSAR values. Also, some Unit 3 doses from DBAs do not fall within (are larger than) the SSAR values.

Justification

This variance in DBA source term parameters and doses is acceptable because calculated doses for the ESBWR design are shown in DCD Chapter 15 to be within limits set by regulatory guidance documents and applicable regulations. These DCD analyses determined DBA dose results based on assumed site parameters for short term (accident) meteorological dispersion factors (χ/Q). Unit 3 site-specific short term χ/Q values are demonstrated in FSAR Table 2.0-201 to fall within (are less than) the associated DCD site parameter values. Therefore, the dose consequences for the DBAs evaluated in DCD Chapter 15 are bounding and applicable for the Unit 3 site, and as shown in DCD Chapter 15 analyses, are within limits set by regulatory guidance documents and applicable regulations.

Variance: NAPS ESP VAR 2.0-7 - Coordinates and Abandoned Mat Foundations

Request - Coordinates

This is a request to use the set of values given in FSAR Figure 2.0-205 as COORDINATES (STATE PLANE NAD 83 VA SOUTH ZONE) rather than the ESP (Reference 1), Appendix A, Figure 1 values given as Coordinates (State NAD 83 South Zone).

There is an error associated with the coordinates of the proposed facility boundaries, which are the coordinates of the eight points that define “ESP Plant Parameter Envelope” shown in ESP, Appendix A, Figure 1. In the ESP, Appendix A, Figure 1, Note 1 states: “North Anna Site and State NAD 83 (South Zone) coordinates are shown as noted.” However, the set of values given as Coordinates (State NAD 83 South Zone) are incorrect as shown. A variance from ESP, Appendix A, Figure 1, Note 1 is requested to correct these values.

The error with the coordinates originated in Dominion Letter 05-785B (Reference 2). In that letter, the response to Draft Safety Evaluation Report (Reference 3), Open Item 2.4-1 contained incorrect State Plane coordinates. Corrected and revised values were provided to NRC in Dominion Letter 05-457 (Reference 4). Figure 1 of the ESP contains the incorrect values; therefore, correction of the coordinates is required.

Justification

This variance is acceptable because it is an administrative change to establish the correct State Plane coordinates.

Request - Abandoned Mat Foundations

This is a request to not remove the abandoned mat foundations for the originally planned North Anna Units 3 and 4 unless a Unit 3 Seismic Category I or II structure would be located above an abandoned foundation. ESP Appendix A, *Characteristics of the Dominion Nuclear North Anna, LLC ESP Site*, contains Figure 1 (Figure 2.4.14-1), *The Proposed Facility Boundary for the ESP Site*. Note 2 on Figure 1 states: “Abandoned Unit 3 and 4 Reactor Building Mat Foundations are to be removed.” This corresponds to Note 2 on ESP SSAR, Figure 1.2-4. The requirement to remove the foundations was established to address the possibility that a Seismic Category I or II structure might be situated above a foundation.

After ESP SSAR, Figure 1.2-4, Note 2 was written, the ESBWR was selected for Unit 3, and the arrangement of a single ESBWR unit allows the power block Seismic Category I and II structures to be located away from the abandoned mat foundations. Therefore it is no longer necessary to remove the abandoned foundations. A variance from ESP, Appendix A, Figure 1, Note 2 is requested.

Justification

It is now known that the abandoned Units 3 and 4 reactor building mat foundations will not interfere with the Unit 3 Seismic Category I or II structures. Although the abandoned Units 3 and 4 reactor building mat foundations are within the ESP proposed facility boundary (ESP plant parameter envelope) as shown in ESP Appendix A, Figure 1, these mat foundations are located away from the Unit 3 ESBWR power block Seismic Category I and II structures. Therefore, this variance is acceptable because the abandoned foundations will not adversely affect Unit 3 safety-related or Seismic Category I or II structures.

Variance: NAPS ESP VAR 2.3-1 - Tornado Site Characteristics

Request

This is a request to use the Unit 3 site characteristic values for tornadoes provided in FSAR Section 2.3.1.3.2 and Table 2.3-225 rather than the corresponding values provided in ESP Appendix A, SSAR Section 2.3.1.3.2 and SSAR Tables 1.9-1 and 2.3-1. These tornado characteristics are: maximum tornado wind speed, maximum rotational speed, maximum translational speed, pressure drop and maximum rate of pressure drop. The values for these site characteristics in the FSAR do not fall within (are lower than) the corresponding values in the ESP and SSAR and therefore would result in smaller tornado-related loads than would result using the values present in the ESP and SSAR.

Because the ESP was issued based on the SSAR site characteristic values that would result in higher tornado loads, lowering these values is a variance. The ESP and SSAR values were determined before NRC had completed reviews of tornado site characteristics and issued Revision 1 of RG 1.76 in March 2007. Adopting the new lower values in Revision 1 of this RG creates a variance in tornado site characteristic values for the Unit 3 site.

Justification

The variance in tornado site characteristic values is acceptable because compliance with NRC regulations, including 10 CFR 50 Appendix A, GDC 2 is demonstrated by conformance to RG 1.76, Revision 1. The use of RG 1.76, Revision 1 is also consistent with the site parameter values for an ESBWR as shown in FSAR Table 2.0-201. The comparisons in that table demonstrate that the DCD site parameters for tornado characteristics bound the values for Unit 3.

Variance: NAPS ESP VAR 2.4-1 – Void Ratio, Porosity, and Seepage Velocity

Request

This is a request to use the Unit 3 values for void ratio, porosity, and seepage velocity of saprolite rather than the SSAR values. The Unit 3 values are as follows from FSAR Section 2.4.12.1.2: void ratio equals 0.45, total porosity equals 31 percent, effective porosity equals 25 percent, and seepage velocity equals 0.35 ft/day. Corresponding SSAR Section 2.4.12.1.2 values for saprolite are as follows: void ratio equals 0.7, total porosity equals 41 percent, effective porosity equals 33 percent, and seepage velocity equals 0.12 ft/day. The Unit 3 values result in a seepage velocity that does not fall within (is larger than) the SSAR value.

The variance in Unit 3 values for void ratio, porosity, and seepage velocity from the SSAR values results from the use of additional data collected from the Unit 3 subsurface investigation.

Justification

The variance in values for void ratio, porosity, and seepage velocity is acceptable because compliance with 10 CFR 20 is demonstrated in FSAR Section 2.4.13 which evaluates radionuclide concentrations and associated doses as a result of a postulated accidental release of liquid effluents in the groundwater pathways.

Variance: NAPS ESP VAR 2.4-2 – NAPS Water Supply Well Information

Request

This is a request to use corrected information for Unit 3 regarding the NAPS water supply wells rather than the SSAR information. The information in FSAR Table 2.4-17R revises SSAR Table 2.4-17 to correct certain information that is now known to be different and to reflect updated information on water supply wells at the NAPS site.

This variance results from the need to provide corrected information for well No. 2 and the Security Training Building well which is based on a reconsideration of technical content of the references for SSAR Table 2.4-17.

Justification

This variance in the NAPS water supply well information is acceptable because the corrected and new information continues to support the conclusions in SSAR Section 2.4.12.1.3 that: “Any groundwater supply required by the new units would likely come from an increase in the storage capacity for the existing wells or from drilling additional wells. In either event, additional groundwater withdrawal by the new units is not expected to impact any offsite wells due to: 1) their distance from the site, 2) the direction of the hydraulic gradient toward Lake Anna and the lake’s recharge effect, and 3) the existence of hydrologic divides between the ESP site and the offsite wells.”

Variance: NAPS ESP VAR 2.4-3 - Well Reference Point Elevation

Request

This is a request to use corrected information for Unit 3 regarding observation well No. WP-3 rather than the SSAR information. The information in FSAR Table 2.4-15R revises SSAR Table 2.4-15 to correct the reference point elevation that is now known to be different and to reflect corrected information on groundwater levels for this well at the NAPS site.

This variance results from the need to provide the corrected reference point elevation for observation well No. WP-3. The reference point elevation for well No. WP-3 provided in SSAR Table 2.4-15 was based on a field observation, specifically a label attached to the well surface casing. To remove the uncertainty in the elevation, which is reflected in the footnote in FSAR Table 2.4-15R, a field survey was performed in early 2009. The corrected reference point elevation is based on the survey measurement of the reference point for this well.

Justification

The variance in the observation well information is acceptable because the new corrected information continues to identify that there are observation wells installed for the independent spent fuel storage installation (ISFSI). There is no change to the information on this well in

FSAR Section 2.4.12.1.2: “The other wells being monitored (P- and WP-) were installed previously for Units 1 and 2 groundwater monitoring purposes around the SWR and the ISFSI, respectively. FSAR Figure 2.4-206 shows the locations of the observation wells.”

The corrected reference point elevation resulted in minor revisions to FSAR Table 2.4-15R and FSAR Figures 2.4-207 through 2.4-214b, the piezometric head contour maps for the site. These changes in observed groundwater levels for well No. WP-3, while not near the plant area for Unit 3, have been incorporated into the latest revision of the groundwater flow model. The revised post-construction piezometric head contour map (FSAR Figure 2.4-216) indicates that the maximum groundwater level elevation in the power block area around Seismic Category I structures is approximately 282.6 ft NAVD88 (283.46 ft NGVD29). The changes in observed groundwater levels for well No. WP-3 are also accounted for the analysis of a postulated, accidental release of radioactive liquid effluents to the groundwater at the Unit 3 site.

Variance: NAPS ESP VAR 2.4-4 - Lake Level Increase

Request

This is a request to use a lake level of 249.39 ft NAVD88 (250.25 ft NGVD29) in the FSAR rather than the corresponding ESP Application SSAR value of 249.14 ft NAVD88 (250 ft NGVD29). The new value does not fall within (is larger than) the SSAR value.

Lake level is used throughout FSAR Section 2.4 as an input for various hydrological evaluations. For example, FSAR Section 2.4.1.3 updates SSAR Table 2.4-1, Lake Anna Storage Allocation, which identifies volumes of water stored in Lake Anna based on lake level.

The variance in lake level results from the decision to increase lake level to reduce impacts on the ecology, wetlands, and recreation in Lake Anna and downstream.

Justification

The variance in lake level increase is acceptable because the new lake level is addressed as an input to various hydrological evaluations in FSAR Section 2.4 (for example, storage allocations, flooding, and groundwater). This FSAR section demonstrates that the increase in lake level does not result in hydrological site characteristics that could affect the safe design or siting of Unit 3.

Variance: NAPS ESP VAR 2.4-5 - Lake Anna PMF Level Increase

Request

This is a request to use a Lake Anna PMF level of 266.56 ft NAVD88 (267.42 ft NGVD29) at Unit 3 in the FSAR rather than the corresponding ESP Application SSAR value of 266.53 ft NAVD88 (267.39 ft NGVD29). The new value does not fall within (is larger than) the SSAR value.

The variance in the PMF level results from a revised PMF analysis that incorporates the lake level increase in NAPS ESP VAR 2.4-4 and a peaked unit hydrograph. The revised analysis is consistent with a Lake Anna PMF analysis performed in 2012 for NAPS Units 1 & 2.

Justification

The variance in PMF level increase is acceptable because the new PMF level is addressed in FSAR Section 2.4. This FSAR section demonstrates that the increase in the PMF level does not result in hydrological site characteristics that could affect the safe design or siting of Unit 3.

Variance: NAPS ESP VAR 2.5-1 – Stability of Slopes

Request

This is a request to use the information presented in FSAR Section 2.5.5 on slopes and the safety of the slopes rather than the information in SSAR Section 2.5.5. The slopes near Unit 3 are different from those anticipated in the SSAR, and, for the seismic slope stability analysis, the peak ground acceleration being applied is different. The method of analysis remains essentially the same.

This variance results from the need to provide Unit 3-specific information which is different from that presented in the SSAR.

Justification

This variance in Unit 3 slopes and slope analyses is acceptable because the slopes being considered in FSAR Section 2.5.5 are lower, less steep, and have a smaller applied seismic acceleration than the slopes analyzed in SSAR Section 2.5.5. As a result, the Unit 3 slopes have a higher computed factor of safety against failure, and are shown to be stable under both long-term static and short-term seismic conditions.

Variance: NAPS ESP VAR 2.5-2 - [Deleted]

Variance: NAPS ESP VAR 12.2-1 – Gaseous Pathway Doses

Request

This is a request to use updated information for Unit 3 gaseous effluent doses rather than the SSAR information which referred to ESP-ER Section 5.4. Several of the gaseous pathway doses to the maximally exposed individual (MEI) in FSAR Table 12.2-18bR do not fall within (are greater than) the corresponding values in ESP-ER Table 5.4-9. The Unit 3 values which are higher are shown in bold font in FSAR Table 12.2-18bR.

This variance is due in part to changes in maximum long-term dispersion estimates from those used in the ESP Application as discussed above under NAPS ESP VAR 2.0-1. The variance is also due to changes in maximum annual gaseous release values from those used in the ESP Application, as discussed below in NAPS ESP VAR 12.2-5.

Justification

This variance is acceptable because estimated annual doses from normal gaseous effluent releases remain within applicable limits. FSAR Table 12.2-18bR shows the annual gaseous pathway doses to the maximally exposed individual (MEI) for Unit 3 and compares each to the corresponding estimate from the ESP-ER Table 5.4-9. Not all doses increased due to changes in long term dispersion estimates because the normal release source term is lower for Unit 3 than the composite source term used to bound the multiple reactor types considered in the ESP Application. The effect of these changes is slight increases in two Unit 3 thyroid doses when compared to the earlier estimates for the ESP. The Unit 3 values that exceed the corresponding ESP value are shown in bold font in FSAR Table 12.2-18bR.

Although two of the individual pathway doses increased compared to the ESP Application, all gaseous effluent doses are acceptable when compared with the applicable limits in FSAR Table 12.2-201. As shown, the Unit 3 doses meet the 10 CFR 50, Appendix I, limits. This table also shows that the Unit 3 doses are lower than the corresponding ESP values.

Variance: NAPS ESP VAR 12.2-2 – [Deleted]

Variance: NAPS ESP VAR 12.2-3 – Annual Liquid Effluent Releases

Request

This is a request to use the Unit 3 maximum annual liquid release values provided in FSAR Table 12.2-19bR rather than the corresponding ESP values in EIS Appendix I (Reference 6) and ESP-ER Section 5.4 as referenced in SSAR Section 2.3.5.1. The Unit 3 values for some nuclides do not fall within (are larger than) the ESP and ER values, as shown in bold font in FSAR Table 12.2-19bR.

This variance results from a change in the annual release values for the ESBWR since the ESP-ER table was submitted. ESP-ER Table 5.4-6 presented the annual release values for a single unit nuclear plant, based on a composite of possible radionuclide releases from a number of reactor designs including the ESBWR. ESP-ER Table 5.4-6 also contained more radionuclides than FSAR Table 12.2-19bR, due to the use of the composite set of nuclides from multiple reactor designs.

Justification

This variance is acceptable because the estimated Unit 3 concentrations of normal liquid effluent releases remain within the applicable concentration limits and the annual doses from normal liquid effluent releases remain within applicable limits.

The estimated Unit 3 concentrations of normal liquid effluent releases for all nuclides meet the 10 CFR 20 concentration limits as shown in FSAR Table 12.2-19bR.

The estimated annual doses from Unit 3 to the MEI from liquid effluents are compared with the applicable limit in FSAR Table 12.2-202. The Unit 3 dose meets the 10 CFR Part 50, Appendix I, limit, and the Unit 3 dose estimates are lower than the corresponding ESP values.

Variance: NAPS ESP VAR 12.2-4 - Existing Units' Doses

Request

This is a request to use updated information for doses for the existing units in FSAR Table 12.2-203 rather than the information in SSAR Section 2.3.5.1 that refers to ESP ER Section 5.4, which contains ESP ER Table 5.4-11.

The doses for total body, thyroid, and bone due to the existing units, as shown in FSAR Table 12.2-203, do not fall within (are greater than) the corresponding values in ESP ER Table 5.4-11. Because these values are higher, they are shown in bold font in FSAR Table 12.2-203.

This variance is due to the conservative dose estimates for direct radiation from Units 1 and 2 and the Independent Spent Fuel Storage Installation (ISFSI), which were added to the doses for liquid and gaseous effluents from Units 1 and 2. The direct radiation dose contributions were included in the FSAR dose estimates, but not in the ESP Application dose estimates. The addition of these direct radiation doses to the existing units' doses (annual total body, thyroid, and bone) caused the FSAR values to exceed the SSAR values.

Justification

This variance is acceptable because the dose estimates are more conservative and complete with the addition of the dose contributions from direct radiation from the existing units and the ISFSI. As shown in FSAR Table 12.2-203, the annual total body, thyroid, and bone doses for the site, including the doses from the existing units and the ISFSI, meet the applicable 40 CFR 190 limits.

Variance: NAPS ESP VAR 12.2-5 - Annual Gaseous Effluent Releases

Request

This is a request to use the Unit 3 maximum annual gaseous effluent release values provided in FSAR Table 12.2-17R rather than the corresponding ESP values in EIS (Reference 6) Appendix I and ESP-ER Section 5.4, as reference in SSAR Section 2.3.5.1. The Unit 3 values for some nuclides do not fall within (are larger than) the ESP and ER values, as shown in bold font in FSAR Table 12.2-17R. This variance results from a change in the annual release values for the ESBWR since the ESP-ER table was submitted. ESP-ER Table 5.4-7 presented the annual release values for a single unit nuclear plant, based on a composite of possible radionuclide releases from a number of reactor designs, including the ESBWR. ESP-ER Table 5.4-7 also contained more radionuclides than FSAR Table 12.2-17R, due to the use of the composite set of nuclides from multiple reactor designs.

Justification

This variance is acceptable because the estimated Unit 3 concentrations of normal gaseous effluent releases remain within the applicable concentration limits and the annual doses from normal gaseous effluent releases remain within applicable limits. The estimated Unit 3 concentrations of normal gaseous effluent releases for all nuclides meet the 10 CFR 20 concentration limits as shown in FSAR Table 12.2-17R. The estimated annual doses from Unit 3 to the MEI from gaseous effluent releases are compared with the applicable limit in FSAR Table 12.2-201. The Unit 3 doses meet the 10 CFR 50, Appendix I, limits, and the Unit 3 dose estimates are lower than the corresponding ESP values.

References

1. Early Site Permit (ESP) for the North Anna ESP Site, No. ESP-003, Amendment No. 3, U.S. Nuclear Regulatory Commission, January 2013.
2. Dominion Nuclear North Anna, LLC, letter to U.S. Nuclear Regulatory Commission, Responses to Draft Safety Evaluation Report Open Items, Serial Number 05-785B, March 3, 2005.
3. Draft Safety Evaluation Report for the North Anna Early Site Permit Application, U.S. Nuclear Regulatory Commission, January 2005.
4. Dominion Nuclear North Anna, LLC, letter to U.S. Nuclear Regulatory Commission, Final Safety Evaluation Report Review Items and Revision 5 to the North Anna ESP Application, Serial Number 05-457, July 25, 2005.
5. NUREG-1835, Safety Evaluation Report for an Early Site Permit (ESP) at the North Anna ESP Site, U.S. Nuclear Regulatory Commission, September 2005.
6. NUREG-1811, Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna ESP Site, U.S. Nuclear Regulatory Commission, December 2006.

EXEMPTIONS

An *exemption* must be obtained if information proposed in the COL application is inconsistent with one or more NRC regulation. Exemptions are submitted pursuant to 10 CFR 52.7 and 52.93 and must comply with the special circumstances in 10 CFR 50.12(a).

Exemption 1: Special Nuclear Material Accountability

Introduction

Dominion requests an exemption from the requirements of 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51. Section 70.22(b) requires an application for a license for special nuclear material (SNM) to contain a full description of the applicant’s program for material control and accounting (MC&A) of special nuclear material under §§ 74.31, 74.33, 74.41, and 74.51 (While not containing an explicit exception for Part 50 reactors, § 74.33 applies only to uranium enrichment facilities and thus is not directly implicated in this exemption request). Section 70.32(c) requires a license authorizing the use of special nuclear material to contain and be subject to a condition requiring the licensee to maintain and follow a special nuclear material control and accounting program, measurement control program, and other material control procedures, including the corresponding records management requirements. However, §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 contain exceptions for nuclear reactors licensed under 10 CFR Part 50. The regulations applicable to the MC&A of special nuclear material for nuclear reactors licensed under 10 CFR Part 50 are provided in 10 CFR Part 74, Subpart B, §§ 74.11 through 74.19, excluding § 74.17. The purpose of this exemption request is to seek similar exceptions for this combined license (COL) under 10 CFR Part 52, such that the same regulations will be applied to the special nuclear material MC&A program as nuclear reactors licensed under 10 CFR Part 50.

Summary of Exemption

Applicable Regulation(s): As permitted by 10 CFR 70.17 and 10 CFR 74.7 exemptions are requested from the provisions of 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 relating to SNM accountability. Specifically, this exemption request would extend the current exceptions embodied in these regulations applicable to 10 CFR Part 50 licensees to the requested Unit 3 10 CFR 52 COL.

Specific wording from which exemption is requested:

<u>10 CFR 70.22(b), Contents of applications:</u>

(b) Each application for a license to possess special nuclear material, to possess equipment capable of enriching uranium, to operate an uranium enrichment facility, to possess and use at any one time and location special nuclear material in a quantity exceeding one effective kilogram, except for applications for use as sealed sources and for those uses involved in the operation of a nuclear reactor licensed pursuant to part 50 of this chapter and those involved in a waste disposal operation, must contain a full description of the applicant's program for control and accounting of such special nuclear material or enrichment equipment that will be in the applicant's possession under license to show how compliance with the requirements of §§ 74.31, 74.33, 74.41, or 74.51 of this chapter, as applicable, will be accomplished.

<u>10 CFR 70.32, Conditions of licenses:</u>

(c) (1) Each license authorizing the possession and use at any one time and location of uranium source material at an uranium enrichment facility or special nuclear material in a quantity exceeding one effective kilogram, except for use as sealed sources and those uses involved in the operation of a nuclear reactor licensed pursuant to part 50 of this chapter and those involved in a waste disposal operation, shall contain and be subject to a condition requiring the licensee to maintain and follow:

(i) The program for control and accounting of uranium source material at an uranium enrichment facility and special nuclear material at all applicable facilities as implemented pursuant to § 70.22(b), or §§ 74.31(b), 74.33(b), 74.41(b), or 74.51(c) of this chapter, as appropriate;

(ii) The measurement control program for uranium source material at an uranium enrichment facility and for special nuclear material at all applicable facilities as implemented pursuant to §§ 74.31(b), 74.33(b), 74.45(c), or 74.59(e) of this chapter, as appropriate; and

(iii) Other material control procedures as the Commission determines to be essential for the safeguarding of uranium source material at an uranium enrichment facility or of special nuclear material and providing that the licensee shall make no change that would decrease the effectiveness of the material control and accounting program implemented pursuant to § 70.22(b), or §§ 74.31 (b), 74.33(b), 74.41(b), or 74.51(c) of this chapter, and the measurement control program implemented pursuant to §§ 74.31(b), 74.33(b), 74.41(b), or 74.59(e) of this chapter without the prior approval of the Commission. A licensee desiring to make changes that would decrease the effectiveness of its material control and accounting program or its measurement control program shall submit an application for amendment to its license pursuant to § 70.34.

<u>10 CFR 74.31, Nuclear material control and accounting for special nuclear material of low strategic significance:</u>

(a) General performance objectives. Each licensee who is authorized to possess and use more than one effective kilogram of special nuclear material of low strategic significance, excluding sealed sources, at any site or contiguous sites subject to control by the licensee, other than a production or utilization facility licensed pursuant to part 50 or 70 of this chapter, or operations involved in waste disposal, shall implement and maintain a Commission approved material control and accounting system that will achieve the following objectives:

10 CFR 74.41, Nuclear material control and accounting for special nuclear material of moderate strategic significance:

(a) General performance objectives. Each licensee who is authorized to possess special nuclear material (SNM) of moderate strategic significance or SNM in a quantity exceeding one effective kilogram of strategic special nuclear material in irradiated fuel reprocessing operations other than as sealed sources and to use this material at any site other than a nuclear reactor licensed pursuant to part 50 of this chapter; or as reactor irradiated fuels involved in research, development, and evaluation programs in facilities other than irradiated fuel reprocessing plants; or an operation involved with waste disposal, shall establish, implement, and maintain a Commission-approved material control and accounting (MC&A) system that will achieve the following performance objectives:

10 CFR 74.51, Nuclear material control and accounting for strategic special nuclear material:

(a) General performance objectives. Each licensee who is authorized to possess five or more formula kilograms of strategic special nuclear material (SSNM) and to use such material at any site, other than a nuclear reactor licensed pursuant to part 50 of this chapter, an irradiated fuel reprocessing plant, an operation involved with waste disposal, or an independent spent fuel storage facility licensed pursuant to part 72 of this chapter shall establish, implement, and maintain a Commission-approved material control and accounting (MC&A) system that will achieve the following objectives:

Exemption Discussion

Nuclear reactors licensed under Part 50 are explicitly excepted from the requirements of §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51. There is no technical or regulatory reason to treat nuclear reactors licensed under Part 52 differently than reactors licensed under Part 50 with respect to the MC&A provisions in 10 CFR Part 74. As indicated in the Statement of Considerations for 10 CFR § 52.0(b) (72 Fed. Reg. 49352, 49372, 49436 (Aug. 28, 2007)), applicants and licensees under Part 52 are subject to all of the applicable requirements in 10 CFR Chapter I, whether or not those provisions explicitly mention a COL under Part 52. This regulation clearly indicates that plants licensed under Part 52 are to be treated no differently than plants licensed under Part 50 with respect to the substantive provisions in 10 CFR Chapter I (which includes Parts 70 and 74). In particular, the exception for nuclear reactors licensed under Part 50, as contained in §§ 70.22(b), 70.32(c), 74.31, 74.41, or 74.51, should also be applied to reactors licensed under Part 52.

An exemption from the requirements of §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 would not mean that a MC&A program would be unnecessary or that the COL application would be silent regarding MC&A. To the contrary, the MC&A requirements in Subpart B to Part 74 would still be applicable to the COL just as they are to licenses issued under Part 50. Additionally, the COL application describes the MC&A program for satisfying Subpart B to Part 74.

The exemption is being requested as permitted by 10 CFR 70.17(a) and 10 CFR 74.7. This exemption request is evaluated under 10 CFR § 52.7, which incorporates the evaluation criteria of § 50.12 and are extended to the evaluation of exemptions requested under 10 CFR 70.17(a) and 10 CFR 74.7. These sections allow the Commission to grant an exemption if 1) the exemption is authorized by law, 2) will not present an undue risk to the public health and safety, 3) is consistent with the common defense and security, and 4) special circumstances are present as specified in 10 CFR § 50.12(a)(2). The criteria in § 50.12 encompass the criteria for an exemption in 10 CFR §§ 70.17(a) and 74.7, the specific exemption requirements for Parts 70 and 74, respectively. Therefore, by demonstrating that the exemption criteria in § 50.12 are satisfied, this request also demonstrates that the exemption criteria in §§ 52.7, 70.17(a) and 74.7 are satisfied.

Evaluation Against Exemption Criteria

1. This exemption is not inconsistent with the Atomic Energy Act or any other statute and is therefore authorized by law.

2. An exemption from the requirements of 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 would not present an undue risk to public health and safety. The exemption would extend to the requested Unit 3 COL the exceptions currently included in these sections that are applicable to 10 CFR Part 50 licensees. Furthermore, the COL application contains a description of the applicant’s MC&A program under Subpart B to Part 74. Therefore, the exemption from 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 would not present an undue risk to public health and safety.

3. An exemption from the requirements of 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 would not be inconsistent with the common defense and security. The exemption would extend to the requested Unit 3 COL the exceptions currently included in these sections that are applicable to 10 CFR 50 licensees. Furthermore, the COL application contains a description of the applicant’s MC&A program under Subpart B to Part 74. Therefore, the exemption from §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 is consistent with the common defense and security.

4. The exemption request involves special circumstances under 10 CFR § 50.12(a)(2)(ii). That subsection defines special circumstances as when “[a]pplication of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.” Since the Commission determined that the requirements in 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51 are unnecessary for Part 50 applicants, those requirements are also unnecessary for Part 52 applicants.

As demonstrated above, the exemption complies with the requirements of 10 CFR §§ 50.12, 52.7, 70.17, and 74.7. For these reasons, approval of the requested exemption is requested from the regulations of 10 CFR §§ 70.22(b), 70.32(c), 74.31, 74.41, and 74.51, as described herein.

Exemption 2: *Electric Power Distribution System Functional Arrangement*

Introduction

Pursuant to 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, Dominion requests an exemption from DCD Tier 1 information. The location of the main generator circuit breaker and the two motor-operated disconnects (MODs) in the on-site power supply system are specified in DCD Tier 1, Figure 2.13.1-1, Sheet 1, *Electric Power Distribution System Functional Arrangement*. This figure shows a horizontal dashed line with these components below the line indicating that these components are to be installed in the “Turbine Island/ Transformer Yard” area of the plant. Due to space limitations for Unit 3 at the North Anna Power Station site, an intermediate switchyard is needed for Unit 3 and these components are to be physically located in the intermediate switchyard. As a result, an exemption from DCD Tier 1 to revise the location information for the main generator circuit breaker and the two motor-operated disconnects (MODs) in the above-referenced figure is requested.

Although the off-site power supply system is not part of the ESBWR standard plant design, DCD Tier 1, Figure 2.13.1-1, Sheet 1, also shows the off-site power supply system portion of the normal preferred power supply. Therefore, changes to this figure are needed to show a 500/230 kV intermediate transformer with high side circuit breaker and three MODs in the intermediate switchyard. As a result, an exemption from DCD Tier 1 to revise the off-site power supply system information in the above-referenced figure is requested.

Finally, DCD Tier 1, Figure 2.13.1-1, Sheet 1, shows a dashed line with the “Turbine Island / Transformer Yard” below the line and the “Switchyard” above the line. The addition of labels on each side of this dashed line in the intermediate switchyard drawing is needed to indicate that although the main generator circuit breaker and its MODs are to be located in the intermediate switchyard, there are no changes to the functions performed by these components as part of the on-site power supply system for the ESBWR standard plant design. The portion below the dashed line in the intermediate switchyard is labeled: “ESBWR standard plant.” The portion above the dashed line in the intermediate switchyard is labeled “Unit 3 site-specific design.” As a result, an exemption from DCD Tier 1 to add these labels to the above-referenced figure is requested.

Summary of Exemption

Applicable Regulations: As permitted by 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, an exemption is requested for certain information depicted on DCD, Tier 1, Figure 2.13.1-1, *Electric Power Distribution System Functional Arrangement*, Sheet 1. The changes for this figure are:

An intermediate switchyard is shown on the figure,

The location of the main generator circuit breaker and its MODs in the on-site power supply system is in the intermediate switchyard, A 500/230 kV intermediate transformer with high side circuit breaker and three MODs are included in the off-site power supply system in the intermediate switchyard, and

The dashed line with the “Turbine Island/Transformer Yard” below the line and the “Switchyard” above the line is used inside of the intermediate switchyard to clarify that the departure affects location but not functional performance. The portion below the dashed line in the intermediate switchyard is labeled: “ESBWR standard plant,” and the portion above the dashed line in the intermediate switchyard is labeled “Unit 3 site-specific design.”

Exemption Discussion

The addition of the intermediate switchyard to DCD Tier 1, Figure 2.13.1-1, Sheet 1, adds details regarding the site-specific design of the switchyard for Unit 3 and is consistent with this DCD figure in that it specifies the off-site normal and alternate preferred power supplies are in the switchyard area of the plant. This change more specifically identifies that some of the off-site normal preferred power supply is located in the site-specific intermediate switchyard. Adding the intermediate switchyard to the figure does not change the functions performed by the components shown on this figure and has no effect on how the functions are performed by the components.

As described in departure NAPS DEP 8.1-1, the location of the main generator breaker and its MODs is changed from the Turbine Island/Transformer Yard as shown in DCD Tier 1, to the intermediate switchyard, but there is no change to a design function, the ability to perform a design function, or the types of malfunctions identified for these components as a result of the change in location. Therefore, the proposed departure does not have an adverse effect on an intended design function.

The addition of the 500/230 kV intermediate transformer with high side circuit breaker and three MODs in the intermediate switchyard to DCD Tier 1, Figure 2.13.1-1, Sheet 1, adds details regarding the site-specific design of the off-site power supply system for Unit 3 and is consistent with DCD Tier 1, Section 4.2, *Offsite Power*. No changes to the interface requirements of DCD Tier 1, Section 4.1 are needed because of the addition of these components. The intermediate transformer is used to meet the interface requirements regarding the capability of supplying voltage and frequency to the on-site portions of the normal preferred power supply that will support operation of safety-related loads during design basis operating modes.

The addition of labels on each side of the dashed line in the intermediate switchyard drawing is needed because the main generator circuit breaker and its MODs will not be located in the Turbine Island/Transformer Yard area of the plant. However, the design of these components remains the same as described in the DCD for the on-site power supply system in the ESBWR standard plant. The addition of labels is a conforming change to clarify that these components remain part of the “ESBWR standard plant” while the intermediate transformer, circuit breaker, and MODs in the intermediate switchyard are part of the “Unit 3 site-specific design.”

Evaluation Against Exemption Criteria

1. This exemption is not inconsistent with the Atomic Energy Act or any other statute and is therefore authorized by law.

2. An exemption from DCD Tier 1 information shown in Figure 2.13.1-1, Sheet 1 would not present an undue risk to public health and safety, or be inconsistent with the common defense and security. The exemption would update the figure to change the installation location of ESBWR standard plant components and add site-specific components not included in the ESBWR standard plant design. The exemption will not change the functions performed by the ESBWR standard plant components shown in this DCD Tier 1 figure. There is no adverse effect on an intended design function.

3. The exemption request involves special circumstances under 10 CFR § 50.12(a)(2)(ii). That subsection defines special circumstances as when "[a]pplication of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule." The proposed changes for DCD Tier 1 Figure 2.13.1-1, Sheet 1, are due to space limitations existing at the NAPS site and the need to add site-specific details related to the off-site power supply system. Addition of the site specific details is consistent with DCD Tier 1, Section 4.2, *Offsite Power*. Thus, consideration of the site-specific design details is part of the licensing process. Conformance to the DCD Tier 1 figure information is not required to achieve the underlying purpose of the rule.

4. As required by 10 CFR 52.63(b)(1), the Commission must also consider whether the special circumstances that § 52.7 requires to be present outweigh any decrease in safety that may result from the reduction in standardization caused by the exemption. This departure from Tier 1 information is a result of a site-specific consideration, namely the space limitations for the NAPS site. Therefore, full standardization in this instance is not practical. As stated above, the departure from Tier 1 information will not result in a significant decrease in the level of safety otherwise provided in the design. Therefore, the consideration of 10 CFR 52.63(b)(1) supports the granting of this request for exemption.

As demonstrated above, this exemption complies with the requirements of 10 CFR §§ 50.12, 52.7, and 52.63(b)(1). For these reasons, approval of the requested exemption is requested for certain DCD Tier 1 information represented on Figure 2.13.1-1, Sheet 1, as described herein.

Exemption 3: Ground Response Spectra for Seismic Structural Loads and Floor Response Spectra

NAPS DEP 3.7-1 identifies changes that affect information in DCD Tier 1 and add information to COLA Part 10.

Exemption 3 Introduction

Safe Shutdown Earthquake (SSE) design ground response spectra of 5 percent damping, also termed certified seismic design response spectra (CSDRS), are defined in DCD Tier 1 as free-field outcrop spectra at the foundation level (bottom of the base slab) of the Reactor Building/Fuel Building and Control Building structures, as shown in DCD Tier 1 Figures 5.1-1 and 5.1-2. As specified in DCD Tier 1, Table 5.1-1, Footnote (4) for the Firewater Service Complex, which is essentially a surface founded structure, the CSDRS is 1.35 times the values shown in DCD Tier 1 Figures 5.1-1 and 5.1-2 and is defined as free-field outcrop spectra at the foundation level (bottom of the base slab) of the Firewater Service Complex structure.

For Unit 3, the site-specific seismic conditions described in FSAR Chapter 2 and Section 3.7.1 indicate that certain seismic design characteristics are not bounded by the DCD seismic design parameters. Therefore, Unit 3 defines the SSE to include the CSDRS and the site-specific foundation input response spectra (FIRS) for each seismically qualified structure.

Summary of Exemption

The Unit 3 horizontal and vertical foundation input response spectra for the RB/FB, CB, and FWSC structures are not bounded by the CSDRS at all frequencies. The definition of the SSE for Unit 3 has therefore been revised to include both: 1) the CSDRS, as described in DCD Tier 1, Table 5.1-1, Footnote (4), and DCD Tier 1 Figures 5.1-1 and 5.1-2; and 2) the site-specific FIRS and the SSI input response spectra for the FWSC at the average elevation of the bottom of the concrete fill (Elevation 220 ft NAVD88, 220.86 ft NGVD29), representative of the Unit 3 site seismological and geological conditions. DCD Tier 1, Section 5.1, provides for site-specific soil structure interaction analyses to be performed to confirm the seismic adequacy of the certified design using approved methods and acceptance criteria. Site-specific soil structure interaction (SSI) analyses have been performed for Unit 3 Seismic Category I structures and evaluation of the results has confirmed the standard design to be adequate. The site-specific definition of SSE will be applied in the ITAAC for ensuring seismic capability of the plant.

Exemption Discussion

The exemption involves a new definition in Tier 1 and a change to DCD Tier 1, Table 5.1-1, Footnote (4) to define the Unit 3 SSE for purposes of performing the verification, through inspections, tests, and analyses, that applicable acceptance criteria specified in DCD Tier 1 ITAAC are met for the seismic design, analyses, and qualification of structures, systems, and components. This exemption represents the Tier 1 changes that relate to Departure NAPS DEP 3.7-1 for Tier 2 and Tier 2* information regarding site-specific CSDRS partial exceedances. COLA Part 10 reflects these changes to Tier 1 and includes revisions to site-specific ITAAC.

Evaluation Against Exemption Criteria

According to the ESBWR Design Certification Rule, Section VIII, exemptions from Tier 1 information are governed by the requirements in 10 CFR 52.63(b)(1) and 52.98(f), and these refer to the criteria specified in 10 CFR 52.7. A request for an exemption would be denied if the design change would result in a significant decrease in the level of safety otherwise provided by the design. An evaluation against exemption criteria follows.

1. The exemption is not inconsistent with the Atomic Energy Act or any other statute and is therefore authorized by law.

2. An exemption from DCD Tier 1 would not present an undue risk to public health and safety in that it continues to ensure that seismic design and analyses are performed and verified for Unit 3 using site-specific seismic conditions as well as the standard CSDRS.

3. The exemption would not be inconsistent with the common defense and security because it would ensure that structures, systems, and components at the site are designed, analyzed, and verified to meet requirements for Unit site-specific seismic conditions as well as the standard CSDRS conditions.

4. The exemption request involves special circumstances under 10 CFR 50.12(a)(2)(ii). That subsection defines special circumstances as when "[a]pplication of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule." For Unit 3, the site-specific seismic conditions described in FSAR Chapter 2 and Section 3.7.1 indicate that certain seismic design characteristics are not bounded by the DCD seismic design parameters. Therefore, site-specific SSI analyses have been performed and the analyses and results are provided in FSAR Sections 3.7.2, 3.8.4, and 3.8.5. The changes that involve DCD Tier 1 are set forth in COLA Part 10. These changes augment the ESBWR standard design for the Unit 3 site-specific seismic conditions to ensure that the adequacy of the Unit 3 seismic design and analyses are verified through appropriate ITAAC. The new definition for the site-specific SSE ensures that the as-built plant will be seismically designed, analyzed, and qualified for meeting both the standard design and the site-specific conditions.

5. As required by 10 CFR 52.63(b)(1), the Commission must also consider whether the special circumstances that §52.7 requires to be present outweigh any decrease in safety that may result from the reduction in standardization caused by the exemption. This exemption from DCD Tier 1 information is a result of site-specific conditions, and does not undermine the purpose of standardization because the standard design is maintained, with adjustments to

account for CSDRS exceedances for the Unit 3 site conditions. As stated above, a new definition for a site-specific SSE ensures that the as-built plant will be seismically designed, analyzed, and qualified for meeting the site-specific conditions. Therefore, the consideration of 10 CFR 52.63(b)(1) supports the granting of this request for exemption.

As demonstrated above, the exemption does not result in a significant decrease in the level of safety otherwise provided by the ESBWR standard design and it complies with the requirements of 10 CFR §§50.12, 52.7, and 52.63(b)(1). For these reasons, Dominion requests the granting of this exemption request, and approval of the associated departure.

Table 3-1 [Deleted]

Exemption 4: Liquid Radwaste Effluent Discharge Piping Flow Path

Introduction

Pursuant to 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, Dominion requests an exemption from DCD Tier 1 information. Tier 1 Section 2.10.1 describes that the Liquid Waste Management System (LWMS) discharges processed water "to the environment via the circulating water system." This description refers to the expected use of the cooling tower blowdown line in the circulating water system to transfer liquid radwaste effluent to the environment. To simplify the design of the cooling tower blowdown line, the liquid radwaste effluent discharge pipeline in the LWMS will be designed to not discharge to the cooling tower blowdown line. The liquid radwaste effluent discharge pipeline will be extended to transfer liquid radwaste effluent from the LWMS in the Radwaste Building to the environment. As a result, an exemption from DCD Tier 1 to revise the discharge piping information for the LWMS in the above-referenced subsection is requested.

Summary of Exemption

Applicable Regulations: As permitted by 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, an exemption is requested for certain information described in DCD Tier 1, Section 2.10.1, Design Description. The last sentence of the fourth paragraph states: "The LWMS either returns processed water to the condensate system or discharges to the environment via the circulating water system." This description is changed to: "The LWMS either returns processed water to the condensate system or discharges to the environment using the liquid radwaste effluent discharge pipeline."

Exemption Discussion

As explained in the related departure NAPS DEP 12.3-1, the DCD Tier 1 sentence provided above was intending for the circulating water system, and specifically the cooling tower blowdown line in the system, to be a portion of the discharge flow path from the LWMS in the Radwaste Building to the environment. The liquid radwaste effluent discharge pipeline in the LWMS was to be discharged to the cooling tower blowdown line which would in turn discharge to the environment. For a COL Applicant, the DCD was intending that the cooling tower blowdown line be treated as containing liquid radwaste. To perform the function of containing the liquid radwaste with the performance requirement to not allow inadvertent or unidentified leakage to the environment, the cooling tower blowdown line was to be either enclosed within a guard pipe and monitored for leakage, or made accessible for visual inspections via a trench or tunnel.

The Tier 1 change is to not use the circulating water system, i.e., the cooling tower blowdown line, to transfer radwaste effluent to the environment and to extend the liquid radwaste effluent discharge pipeline to transfer liquid radwaste from the LWMS in the Radwaste Building to the environment. This change involves pipelines that are required to comply with regulations at 10 CFR 20.1406 to minimize, to the extent practicable, contamination of the facility and the environment.

With the Tier 1 change, the circulating water system, i.e., the cooling tower blowdown line, will not be used to contain liquid radwaste; therefore the special design requirements for performing that function will not be required for the Unit 3 cooling tower blowdown line. This change does not have an adverse effect on a DCD described design function because the liquid radwaste effluent discharge pipeline in the LWMS will be extended to transfer liquid radwaste from the Radwaste Building to the environment and that pipeline continues to meet the special design requirements and the regulations. The underground segments of the liquid radwaste effluent discharge pipeline will either be enclosed within a guard pipe and monitored for leakage, or made accessible for visual inspections via a trench or tunnel. The Tier 1 change to use only the liquid radwaste effluent discharge pipeline for transfer to the environment will mean that the Unit 3 design continues to meet the DCD requirement for the piping to comply with 10 CFR 20.1406.

Evaluation Against Exemption Criteria

1. This exemption is not inconsistent with the Atomic Energy Act or any other statute and is therefore authorized by law.

2. An exemption from using the circulating water system, i.e., cooling tower blowdown line, and instead using the liquid radwaste effluent discharge piping for transfer of radwaste effluent to the environment would not present an undue risk to public health and safety, or be inconsistent with the common defense and security. The liquid radwaste effluent discharge piping meets the requirements to minimize, to the extent practicable, contamination of the facility and the environment. The liquid radwaste effluent discharge piping will either be enclosed within a guard pipe and monitored for leakage, or made accessible for visual inspections via a trench or tunnel. There is no adverse effect on an intended design function.

3. The exemption request involves special circumstances under 10 CFR § 50.12(a)(2)(ii). That subsection defines special circumstances as when “[a]pplication of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary

to achieve the underlying purpose of the rule." The proposed changes for DCD Tier 1, Section 2.10.1 are due to the additional work to understand the design needed to meet the special design requirements for piping associated with transfer of liquid radwaste effluent. Not using the cooling tower blowdown line simplifies its site-specific design and is consistent with DCD Tier 1, Section 2.11.8, *Circulating Water System*, which shows that no ITAAC are required for this system. Conformance to the DCD Tier 1, Section 2.10.1 description is not required to achieve the underlying purpose of the rule.

As demonstrated above, the exemption complies with the requirements of 10 CFR §§ 50.12, 52.7, and 52.63(b)(1). For these reasons, approval of the requested exemption is requested from DCD Tier 1, Section 2.10.1, as described herein.

Exemption 5: Design of Structures Housing RTNSS Equipment for Hurricane Wind Generated Missiles

Pursuant to 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, Dominion requests an exemption from DCD Tier 1 information. DCD Tier 1, Table 5.1-1, Envelope of ESBWR Standard Plant Site Parameters, includes criteria for the design of structures housing RTNSS SSCs to resist maximum hurricane winds and hurricane wind generated missiles. NRC guidance contained in RG 1.221, Design-Basis Hurricane and Hurricane Missiles for Nuclear Power Plants, issued October 2011, provides criteria for determining the maximum hurricane wind speed and hurricane wind generated missile velocities. The maximum hurricane wind speed for the Unit 3 site derived in accordance with RG 1.221 is enveloped by the maximum hurricane wind speed given in DCD Tier 1 Table 5.1-1. The guidance in RG 1.221, however, results in higher hurricane wind generated missile velocities than those specified in the DCD for certain postulated hurricane wind generated missiles. For Unit 3, structures housing RTNSS equipment are designed to meet both the hurricane wind generated missile spectra specified in the DCD and the Unit 3 site-specific missile spectra and velocities per the guidance of RG 1.221. Since the missile spectra for hurricane wind generated missiles used in the design of structures housing RTNSS equipment is referenced in Footnote 7 to Table 5.5-1, an exemption is requested to add the requirement that the design of these structures account for higher missile velocities that may be specified by the current guidance in RG 1.221 in addition to the missile spectra specified in the DCD.

Summary of Exemption

Applicable Regulations: As permitted by 10 CFR 52.7 and Section VIII.A.4 of the Design Certification Rule, an exemption is requested for certain information described in DCD Tier 1, Table 5.1-1, Envelope of ESBWR Standard Plant Site Parameters. Table 5.1-1 Footnote 7 states that the hurricane missile spectrum for Seismic Category NS and Seismic Category II structures that house RTNSS equipment is consistent with the tornado missile spectrum identified in this table (Table 5.1-1). However, current NRC guidance for the Unit 3 site in RG 1.221 results in higher missile velocities for some postulated missiles. This exemption modifies Footnote 7 to DCD Tier 1 Table 5.1-1 to add the requirement to account for higher hurricane wind generated missile velocities when the Unit 3 site-specific velocities exceed those specified in the DCD.

Exemption Discussion

As explained in the related departure NAPS DEP 19A-1, ESBWR structures housing RTNSS equipment are designed to protect RTNSS equipment from the effects of hurricane winds and hurricane wind generated missiles. Although the Unit 3 site-specific hurricane wind speed is bounded by hurricane wind speed specified in the DCD, current NRC guidance in RG 1.221 results in higher velocities for some hurricane wind generated missiles than specified in the DCD. The NRC issued RG 1.221 subsequent to GEH's submittal of the Design Certification Application for the ESBWR.

The NRC issued the final design certification rule on October 15, 2014 (79 FR 61944) as Appendix E to 10 CFR 52. The ESBWR design certification rule address the revised NRC guidance related to hurricane winds and hurricane wind generated missiles. Specifically, Section IV.A.2.g requires that applicants referencing the ESBWR design include information that demonstrates that structures and components described in DCD Sections 3.3.2 and 3.5.2 are either bounded by tornado wind loads and missiles or meet applicable NRC requirements with respect to hurricane wind. The DCD sections referenced in Section IV.A.2.g refer to Seismic Category I structures. Unit 3 Seismic Category I structures are designed to meet the tornado wind loads and missiles and the DCD specified tornado wind and missile parameters bound those that could result from the most severe hurricane postulated for the Unit 3 site.

The ESBWR design certification rule does not specifically address the requirements for hurricane wind generated missiles used for the design of other structures that may house RTNSS equipment. Design requirements for non-Seismic Category I structures housing RTNSS equipment are addressed in DCD Appendix 19A. Consistent with changes described in NAPS DEP 19A-1, this exemption modifies Footnote 7 to DCD Tier 1 Table 5.1-1 to specify that the Unit 3 site-specific missile velocities derived in accordance with RG 1.221 are used in the design of structures housing RTNSS equipment when the site-specific missiles are more severe than the missiles specified in the DCD.

Evaluation Against Exemption Criteria

According to the ESBWR Design Certification Rule, Section VIII, exemptions from Tier 1 information are governed by the requirements in 10 CFR 52.63(b)(1) and 52.98(f), and these refer to the criteria specified in 10 CFR 52.7. A request for an exemption would be denied if the design change would result in a significant decrease in the level of safety otherwise provided by the design. An evaluation against exemption criteria follows.

1. This exemption is not inconsistent with the Atomic Energy Act or any other statute and is therefore authorized by law.

2. An exemption from DCD Tier 1 would not present an undue risk to public health and safety in that it provides more conservative criteria for specifying the parameters of hurricane wind generated missiles used in the design of structures housing RTNSS equipment and continues to ensure that such structures are designed to withstand the effects of hurricane wind generated missiles.

3. The exemption would not be inconsistent with the common defense and security because it would ensure that structures, systems, and components at the site are designed to meet requirements for Unit 3 site-specific hurricane wind generated missiles as well as the standard plant missile parameters.

4. The exemption request involves special circumstances under 10 CFR 50.12(a)(2)(ii). That subsection defines special circumstances as when “[a]pplication of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.” For Unit 3, the site-specific hurricane wind generated missile velocities derived in accordance with the guidance in RG 1.221 exceed the missile velocities specified in the DCD. The changes that involve DCD Tier 1 are set forth in COLA Part 10. These changes augment the ESBWR standard design for the Unit 3 site-specific hurricane wind generated missiles used in the design of structures housing RTNSS equipment and ensure that the adequacy of the Unit 3 hurricane wind generated missile design and analyses are verified through appropriate ITAAC.

5. As required by 10 CFR 52.63(b)(1), the Commission must also consider whether the special circumstances that §52.7 requires to be present outweigh any decrease in safety that may result from the reduction in standardization caused by the exemption. This exemption from DCD Tier 1 information is a result of site-specific conditions, and does not undermine the purpose of standardization because the standard design is maintained, with adjustments to account for site-specific hurricane wind generated missiles that may exceed those specified in the DCD. Therefore, the consideration of 10 CFR 52.63(b)(1) supports the granting of this request for exemption.

As demonstrated above, the exemption does not result in a significant decrease in the level of safety otherwise provided by the ESBWR standard design and it complies with the requirements of 10 CFR §§50.12, 52.7, and 52.63(b)(1). For these reasons, granting of the exemption request, and approval of the associated departure, is requested.

North Anna 3 Combined License Application

Part 8: Security

Revision 5

June 2016

REVISION SUMMARY

Revision 5

Section	Changes	Reason for Change
8C	Revision 1 issued	More fully describe how the requirements of 10 CFR 73.67 will be met
	Revision 2 issued	RAI 01.05-04 (Part 1), Describe how the requirements of 10 CFR 73.67 will be met
		RAI 01.05-05, Describe actions for notification of a site-specific credible threat

Revision 4

Section	Changes	Reason for Change
Description page	Added Special Nuclear Protection Program to the Part 8 scope list; changed the referenced submission letter for CAS/SAS from “NA3-13-011” to “NA3-13-021”; added description of new Appendix 8C, North Anna Power Station Unit 3 Special Nuclear Material Program	New security document to meet requirements of 10 CFR 73.67(f); to reflect revised response to CAS/SAS-related RAI 13.06-30 and -32

Revision 4

Section	Changes	Reason for Change
8B	Initial issue of Unit 3 ESBWR-based Appendix 8B, “Mitigative Strategies Description and Plans”	This document reflects the EF3 R3, Mitigative Strategies Description and Plans (R3 includes changes from all EF3 RAIs through 19.03-37) as applicable to NA3, along with NA3-specific changes from the US-APWR S-COLA Mitigative Strategies Description and Plans, R0, and any unincorporated changes from RAI responses on the US-APWR S-COLA Plan. Changes from the following US-APWR S-COLA RAI responses are incorporated, in whole or in part, in this document, or the document otherwise addresses the RAI and response: 19-1, 19-3, 19-4, 19-5(S1), 19-6, 19-7, 19-8, 19-11, 19-12, 19-14, 19-15, 19-16, 19-17, 19-19, 19-20, 19-21, 19-22, 19-24, 19-25, 19-26, and 19-27.
8C	New	New security document to meet requirements of 10 CFR 73.67(f)

Revision 3

Section	Changes	Reason for Change
Description page	Removed “Plan” after “Security” on first line and added “Mitigative Strategies Description and Plans”, “Evaluation of CAS/SAS Design for No Single Act” and “NA3 COL 13.6-16-A, Security Site Arrangement - Fields of Fire” to list of security documents and added withholding information for the security documents.	Address the security documents in the COLA

Revision 3

Section	Changes	Reason for Change
8B	Added new page for the North Anna Unit 3 Mitigative Strategies Description and Plans. Added statement, “To be provided in the December 2013 COLA submittal.”	Consistency with EF3

Part 8, Security, consists of the following documents for North Anna Unit 3:

- Security Plan
- Training and Qualification Plan
- Safeguards Contingency Plan
- Mitigative Strategies Description and Plans
- Evaluation of CAS/SAS Design for No Single Act
- NA3 COL 13.6-16-A, Security Site Arrangement - Fields of Fire
- Special Nuclear Material Physical Protection Program

The North Anna Power Station Units 1 and 2, and Unit 3 Combined Operating License Application (COLA) Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan and Independent Spent Fuel Storage Installation Security Program (COLA PSP) includes the Physical Security Plan, Training and Qualification Plan, Safeguards Contingency Plan and Cyber Security Plan. The COLA PSP, except for the Cyber Security Plan, contains Safeguards Information as defined by 10 CFR 73.21 and its disclosure to unauthorized individuals is prohibited by Section 147 of the Atomic Energy Act of 1954, as amended. These plans were submitted to NRC by separate letter (Dominion Serial No. NA3-16-018).

The Cyber Security Plan is provided as Appendix 8A. The Cyber Security Plan contains Security-Related Information and is withheld from public disclosure pursuant to 10 CFR 2.390.

The North Anna Power Station Unit 3 Mitigative Strategies Description and Plans is provided as Appendix 8B. The Mitigative Strategies Description and Plans contains Security-Related Information and is withheld from public disclosure pursuant to 10 CFR 2.390.

The Evaluation of CAS/SAS Design for No Single Act report contains Safeguards Information as defined by 10 CFR 73.21 and its disclosure to unauthorized individuals is prohibited by Section 147 of the Atomic Energy Act of 1954, as amended. This report was submitted to NRC by separate letter (Dominion Serial No. NA3-13-021).

DCD COL Item 13.6-16-A is addressed with drawing NA3 COL 13.6-16-A, Security Site Arrangement – Fields of Fire. NA3 COL 13.6-16-A contains Safeguards Information as defined by 10 CFR 73.21 and its disclosure to unauthorized individuals is prohibited by Section 147 of the Atomic Energy Act of 1954, as amended. This drawing was submitted to NRC by separate letter (Dominion Serial No. NA3-13-011 and Dominion Serial No. NA3-13-021).

The North Anna Power Station Unit 3 Special Nuclear Material (SNM) Physical Protection Program is provided as Appendix 8C. The SNM Physical Protection Program contains Security-Related Information and is withheld from public disclosure pursuant to 10 CFR 2.390.

Appendix 8A North Anna Unit 3 Cyber Security Plan

Appendix 8B North Anna Unit 3 Mitigative Strategies Description and Plans

Appendix 8C North Anna Unit 3 Special Nuclear Material (SNM) Physical Protection Plan Program Description

North Anna 3 Combined License Application

Part 10: Tier 1/ ITAAC/Proposed License Conditions

Revision 8

June 2016

REVISION SUMMARY

Revision 8

Section	Changes	Reason for Change
1	Revised Footnote (4) to Table 5.1-1	To include both elevations for FWSC FIRS
1.1.1	RAI 03.05.01.04-02, Missiles Generated by Tornadoes and Extreme Winds	
	Added reference to the SSI input response spectra for the FWSC at the average elevation of the bottom of the fill concrete	Consistency with FSAR Section 3.7.1
2.4.2; Table 2.4.2-1	Added ITAAC for structural fill on the sides of Seismic Category I structures	Address item discussed with the NRC in the April 15, 2015 public meetings
2.4.15 through 2.4.18, 2.4.20 through 2.4.22; Tables 2.4.15-1 through 2.4.18-1, and 2.4.20-1 through 2.4.22-1	Clarified development of FIRS; editorial changes	Incorporate information regarding site-specific seismic analysis; editorial
2.4.15, 2.4.16, 2.4.17,2.4.18; Tables 2.4.15-1 through 2.4.18-1	RAI 03.07.02-24, SSSI Analyses - Non-Seismic Category I	
Tables 2.4.15-1, 2.4.16-1, 2.4.17-1 & 2.4.18-1	RAI 03.07.02-16, Site-Specific SSI Effects	
2.4.15 through 2.4.18; Tables 2.4.15-1 through 2.4.18-1	Revised the ITAAC design descriptions; revised the ITAAC tables	Incorporate more specifics regarding evaluations of Seismic Category II and Radwaste Building structures for SSI analysis methods and acceptance criteria and SSSI evaluations of potential effects on adjacent Seismic Category I structures
2.4.16	RAI 02.02.03-10, Evaluation of Potential Accidents	
Table 2.4.19	RAI 04.02-1 R1, Fuel Assembly and Control Rod Loads	
2.4.20; Table 2.4.20-1	RAI 03.07.03-01, Buried Pipe Input Motions	
2.4.21	Added ITAAC for Access Tunnel	Incorporate ITAAC for Seismic Category II Access Tunnel

Revision 8 *(continued)*

Section	Changes	Reason for Change
2.4.22	Added ITAAC for Radwaste Tunnel	Incorporate ITAAC for Safety Class RW-IIa Radwaste Tunnel
3.11	RAI 01-6, Financial Protection	

Revision 7

Section	Changes	Reason for Change
1.1.1	Deleted “NAPS DEP 3.7-1” from action statement. Corrected DCD Tier 1 Reference figures for CSDRS	Editorial and typographical
Table 5.1-1, Footnote (4)	Tier 1 Departures- SSE design ground response spectra of 5% damping is defined as the higher of a combination of the CSDRS free-field outcrop spectra at the foundation level (bottom of the base slab) of the Reactor/Fuel and Control Building structures and the Unit 3 site-dependent SSE at grade.	DEP 3.7-1
2.4.19	Changed reference from “Table 2.4-18-1” to “Table 2.4-19-1”	Correction
3.8.1	Deleted statement “or other NRC endorsed guidance in effect six months prior to completion of the assessment” from first and third paragraphs	Consistency with EF3 COLA
3.8.2	Deleted reporting requirements in the license condition for BDB external events strategies and guidance. Added requirement to use JLD-ISG-2012-01 to develop strategies.	Consistency with EF3 COLA
3.10	Added section for steam dryer	DCD R10

Revision 6

Section	Changes	Reason for Change
Tier 1 Information	Revised IBR sentence to include “with the following departures and/or supplements”	New Tier 1 departure added that affects ITAAC
Tier 1, 1.1.1, Definitions	Added definition	NAPS DEP 3.7-1

Revision 6 *(continued)*

Section	Changes	Reason for Change
Tier 1, 2.1, Design Certification ITAAC	Revised IBR sentence to include “with the following departures and/or supplements”	New Tier 1 departure added that affects ITAAC
Tier 1, 2.1.1, Design Certification ITAAC Departure	Incorporated departure	NAPS DEP 12.3-1
Tier 1, 2.1.2, Design Certification ITAAC Departure	Added new section explaining departure from ITAAC	New Tier 1 departure added that affects ITAAC
Tier 1, North Anna Unit 3 Specific Figure 2.13.1-1 Sh. 1	Added new figure	New Tier 1 departure added that affects ITAAC
2.4.15, 2.4.16, 2.4.17, 2.4.18, 2.4.19; Tables 2.4.15-1, 2.4.16-1, 2.4.17-1, 2.4.18-1, 2.4.19-1	Added information related to seismic and dynamic loads	NAPS DEP 3.7-1
3.1	Added License Condition for emergency planning actions	EF3 RAIs 13.03-07, 13.03-13
3.2	Added License Conditions for Initial Test Program	EF3 14.02-4
3.3	Added License Condition for byproduct, source and special nuclear material	NA3 ESBWR R-COLA RAI 01-4
3.4	Added License Condition for Fire Protection Program actions	EF3 RAI 01.05-7
3.5	Added license conditions for operational program implementation	EF3 RAI 19.03-38
3.6	Added License Condition for operational program readiness	EF3 RAI 19.03-38
3.7	Added License Condition for Emergency Action Levels	EF3 RAIs 13.03-66, 19.03-38
3.8	Added License Conditions for Fukushima actions	EF3 RAIs 01.05-2, 01.05-3, 01.05-4, 01.05-5, 01.05-6, 13.03-65
3.9	Added License Condition for explosively actuated valves	Consistency with EF3 COLA

Revision 5

Section	Changes	Reason for Change
Cover	Changed title from “Tier 1/ITAAC” to “Tier 1/ITAAC/Proposed License Conditions	Added section for license conditions
Title	Changed from “Tier 1 Information and Inspections, Tests, Analyses, and Acceptance Criteria” to “Tier 1 Information Inspections, Tests, Analyses, and Acceptance Criteria, and Proposed License Conditions”	Added section for license conditions
2.1	Deleted “in”	Editorial
2.2	Inserted “... for systems within the scope of the DCD…”; deleted “in”	Address ITAAC for site-specific Physical Security
2.2.1	New section	Address ITAAC for site-specific Physical security
Table 2.2.1-1	New table	Address ITAAC for site-specific Physical security
Table 2.3-1, Item 1.1 ITA	Inserted “that constitute the bases for the classification scheme”	Consistency with EF3 COLA
Table 2.3-1, Items 1.1.1 & 1.1.2 AC	Editorial	Consistency with EF3 COLA
Table 2.3-1, Items 1.1.2 & 6.1	RAI 13.03-3 - Revised, Emergency Action Levels	
Table 2.3-1, Item 2.1 AC	Corrected number from 2.1.1; changed “A report exists that confirms communications have” to “A means to notify responsible organizations, within 15 minutes after the licensee declares an emergency, has”	Editorial; improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Item 2.2 EPPE	Changed “COL EP II.D.2” to “COL EP II.E.2”	Editorial
Table 2.3-1, Item 2.2 AC	Editorial	Improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Items 2.3, 8.1.1 through 8.1.3	RAI 13.03-6, Onsite Exercise Objectives in ITAAC	
Table 2.3-1, Item 2.3 AC	Editorial	Improve nomenclature per RIS 2008-05 R1

Revision 5 *(continued)*

Section	Changes	Reason for Change
Table 2.3-1, AC Items 3.1.1-3.1.1.4, 3.2, 4.1, 5.1.2 - 5.1.7 & 5.2.2, 6.1, 7.1.1, 7.1.2	Editorial	Consistency with EF3 COLA
Table 2.3-1, Item 4.0	Deleted	US-APWR S-COLA RAI 14.03.10-4
Table 2.3-1, Item 5.1, EP	Changed from “operations” to “operational”	Editorial
Table 2.3-1, Item 5.1, AC	Deleted “181 square meters)	Editorial
Table 2.3-1, Item 5.1.1 AC	Editorial; revised to reflect correct values for TSC floor space	Consistency with EF3 COLA
Table 2.3-1, Item 5.2.4 AC	New item	Improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Item 6.2 AC	Corrected number from 6.2.1; revised to include a methodology for determining the magnitude of a release	Editorial; improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Item 6.3 AC	Revised to include continual assessment of the impact from a release of radioactive materials	Improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Item 6.4 ITA & AC	Revised to include differential air temperature and deleted measurement of ambient air temperature at 48.4 m	Improve nomenclature per RIS 2008-05 R1 and consistency with SSAR Section 2.3.3.1.1
Table 2.3-1, Item 6.5 ITA & AC	Revised to include a test of EPIP capabilities	EF3 RAI 13.03-69
Table 2.3-1, Item 6.6 AC	Editorial	Consistency with EF3 COLA
Table 2.3-1, Item 6.7 AC	Revised to include the specified isotopes and comparing the dose estimates with the EPA PAGs	Improve nomenclature per RIS 2008-05 R1
Table 2.3-1, Item 8.1.2	Deleted note	Note is not relevant
Table 2.3-1, Items 8.1.2 & 8.1.3	RAI 13.03-7, Offsite Exercise Objectives in ITAAC	
Table 2.3-1, Item 9.1	RAI 14.03.10-1.1, E-Plan Procedure Submittal	
2.4.1, Table 2.4.1-1	Replaced entirely the changes provided with RAI 02.05.04-20 response with new content to address fill concrete under Seismic Category I structures	EF3 RAI 02.05.04-40

Revision 5 *(continued)*

Section	Changes	Reason for Change
2.4.3	Inserted section and renumbered following sections and tables accordingly (including all citations to those items)	Consistency with EF3 COLA
2.4.3, Table 2.4.3-1 (was 2.4.2 & Table 2.4.2-1)	RAI 09.02.01-8, PSWS Heat Removal ITAAC Acceptance Criteria	
2.4.4 through 2.4.8, 2.4.10, 2.4.13 & 2.4.14	Changed “No entry” to “No ITAAC are required”	DCD R9
2.4.8, Table 2.4.8-1 (was 2.4.7 & Table 2.4.7-1)	RAI 14.03.06-1, Add ITAAC for Off-site Power Interface	
2.4.8	Deleted duplicate “refer to” in Item 2 of third paragraph of design description	Editorial
2.4.11 (was 2.4.10)	RAI 14.03.07-1, Revise Reference to Mobile LWMS	
2.4.12 (was 2.4.11)	RAI 14.03.07-2, Revise Reference to Mobile SWMS	
2.4.15, Table 2.4.16-1	Added section for Turbine Building ITAAC	EF3 RAI 03.07.02-5
2.4.16, Table 2.4.16-1	Added section for Radwaste Building ITAAC	EF3 RAI 03.07.02-5
2.4.17, Table 2.4.17-1	Added section for Service Building ITAAC	EF3 RAI 03.07.02-5
2.4.18, Table 2.4.18-1	Added section for Ancillary Diesel Building ITAAC	EF3 RAI 03.07.02-5
3	Added section for license conditions	Future information placeholder

Revision 1

Section	Changes
Table 2.3-1	RAI 14.03.10-1.2, ITAAC Table Correction
	RAI 14.03.10-1.4, ITAAC for U3 E-Plan Exercise
	Corrected incomplete reference in EP Program Elements column, 1.1 and reference to EP in Inspection, Tests, Analyses column, 1.1

TIER 1 INFORMATION
INSPECTIONS, TESTS, ANALYSES, AND ACCEPTANCE CRITERIA, AND
PROPOSED LICENSE CONDITIONS

1. Tier 1 Information

DCD Tier 1 is incorporated by reference with the following departures and/or supplements.

1.1.1 Definitions

Add the following at the end of this section:

Unit 3 Seismic Design Response Spectra, for purposes of seismic requirements for Seismic Category I SSCs as specified in Tier 1, means the seismic design response spectra based on the results of the Unit 3 site-specific SSI analyses described in FSAR Section 3.7.2. Specifically, Safe Shutdown Earthquake (SSE) design ground motion for purposes of seismic design, analysis, and qualification of Unit 3 plant structures, systems, and equipment, is defined by two sets of ground motion acceleration response spectra:

- the single envelope design ground motion response spectra or Certified Seismic Design Response Spectra (CSDRS) described in FSAR Section 3.7.1.1.3 that defines the SSE design motion for seismic design of ESBWR Standard Plant, and the site-specific Foundation Input Response Spectra (FIRS) described in FSAR Section 3.7.1.1.4.2, representative of the Unit 3 site specific seismological and geological conditions.

FSAR Figures 2.0-201 through 2.0-204 present these 5% damped acceleration response spectra that define the design ground motion as a free-field outcrop motion at the foundation bottom of each Seismic Category I structure. In addition, FSAR Figure 3.7.1-285 presents the SSI input response spectra for the FWSC at the average elevation of the bottom of the concrete fill (Elevation 220 ft NAVD88, 220.86 ft NGVD29) as further discussed in FSAR Section 3.7.1.1.4.2.3. DCD Tier 1 Figures 5.1-1 and 5.1-2 present the standard design CSDRS.

For each structure and each equipment location within the buildings, in-structure response spectra (ISRS) are developed. The site-specific ISRS that exceed the standard design ISRS, are used in conjunction with the standard design ISRS for seismic design and qualification of equipment and components.

This approach applies to SSCs that are required to withstand SSE loads. Similarly, other SSCs that are specifically required to meet SSE seismic demands are designed, analyzed, and qualified using the process in FSAR Sections 3.7.1 and 3.7.2 for applying the CSDRS and site-specific FIRS. The same approach is applied for the Seismic Category II and Radwaste Building structures.

DCD Tier 1 Table 5.1-1 **Envelope of ESBWR Standard Plant Site Parameters**

Replace footnote (4) with the following:

(4) Safe Shutdown Earthquake (SSE) design ground motion, for purposes of seismic design analysis, and qualification of Unit 3 Reactor Building/Fuel Building (RB/FB) and Control Building (CB) structures, systems, and components, is defined by two sets of ground motion acceleration response spectra: the standard design Certified Seismic Design Response Spectra (CSDRS) and the site-specific Foundation Input Response Spectra (FIRS) for these two buildings. For the Firewater Service Complex (FWSC), which is essentially a surface founded structure, the SSE design ground motion is defined as 1.35 times the spectra of the CSDRS and the FWSC site-specific FIRS defining the input design motion at FWSC basemat bottom Elevation 282 ft. FSAR Figures 2.0-201 through 2.0-204 present these spectra that define the free-field outcrop motion at the foundation bottom of each structure. DCD Tier 1 Figures 5.1-1 and 5.1-2 present the standard design CSDRS. To account for the effects of the concrete fill placed below the FWSC basemat on the ground motion, the site-specific analyses of the FWSC consider two sets of input design motion that are defined at the bottom of the FWSC basemat (Elevation 282 ft) and concrete fill nominal bottom (Elevation 220 ft) and are consistent with FWSC FIRS (FSAR Section 3.7.1.1.4.2.3). The same process for developing the SSE design ground motion is followed for the Seismic Category II and Radwaste Building structures.

Add the following to footnote (7):

The hurricane missile spectrum and velocities are adjusted as necessary to also envelope the Unit 3 site-specific hurricane missile velocities calculated in accordance with RG 1.221.

2. COLA ITAAC

The Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) for the COLA are provided in tabular form, consistent with the format shown in RG 1.206 Table C.II.1-1.

The COLA-ITAAC consist of the following four parts:

1. Design Certification ITAAC
2. Emergency Planning ITAAC
3. Physical Security ITAAC
4. Site-Specific ITAAC

This set of COLA-ITAAC is included herein. Completion of the ITAAC is a proposed condition of the combined license to be satisfied prior to fuel load.

2.1 Design Certification ITAAC

The Design Certification ITAAC are contained in DCD Tier 1, which is incorporated by reference with the following departures and/or supplements.

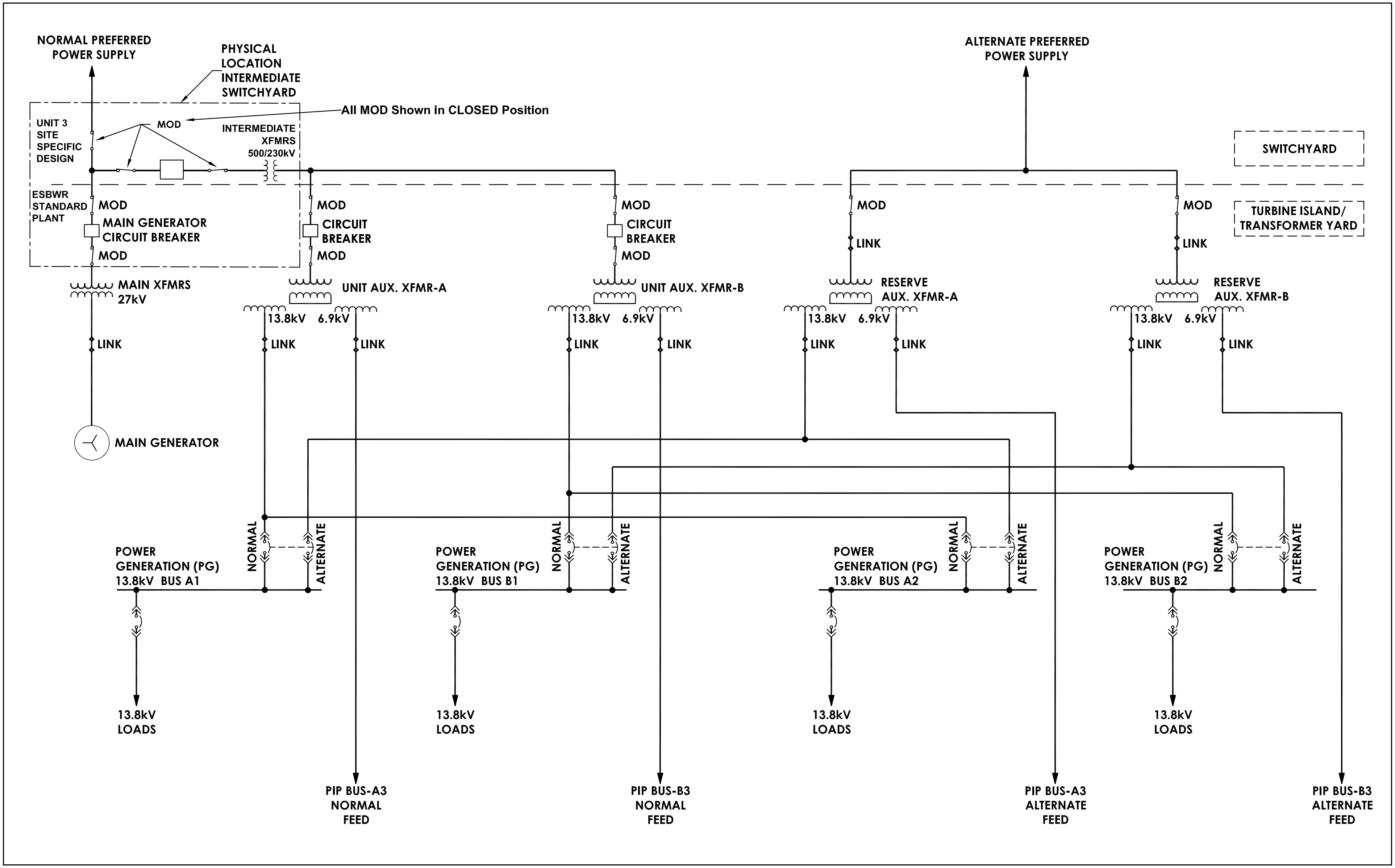
2.1.1 **Liquid Radwaste Effluent Discharge Piping Flow Path**

There is a departure from DCD Tier 1, Section 2.10.1, as described in COLA Part 7. The Unit 3 piping used for the flow path from the Liquid Waste Management System (LWMS) in the Radwaste Building to the environment will not include piping in the circulating water system. The last sentence of the fourth paragraph of this section is replaced with the following: “The LWMS either returns processed water to the condensate system or discharges to the environment using the liquid radwaste effluent discharge pipeline.”

2.1.2 **Electric Power Distribution System Functional Arrangement**

There is a departure from DCD Tier 1, Section 2.13.1, Figure 2.13.1-1, Sheet 1, as described in COLA Part 7. The Unit 3 Electric Power Distribution System Functional Arrangement is as shown on the next page, which provides the North Anna Unit 3 Specific Figure 2.13.1-1, Sheet 1. This Unit 3 specific figure replaces DCD Tier 1 Figure 2.13.1-1, Sheet 1, where the figure is cited in DCD Tier 1, Section 2.13.1.

North Anna Unit 3 Specific Figure 2.13.1-1 Sh 1. Unit 3 Electric Power Distribution System Functional Arrangement



2.2 Physical Security ITAAC

The Physical Security ITAAC for systems within the scope of the DCD are contained in DCD Tier 1, which is incorporated by reference in Section 1.

2.2.1 Site Specific Physical Security ITAAC

Design Description

The physical security system provides physical features to detect, delay, assist response to, and defend against the design basis threat (DBT) for radiological sabotage. The physical security system consists of physical barriers and an intrusion detection system. The details of the physical security system are categorized as Safeguards Information. The physical security system provides protection for vital equipment and plant personnel.

1. Vital Area and Vital Area Barrier:
   a. Vital equipment will be located only within a vital area.
   b. Access to vital equipment will require passage through at least two physical barriers.
2. Protected Area Barrier:
   a. Physical barriers for the protected area perimeter will not be part of vital area barriers.
   b. Penetrations through the protected area barrier will be secured and monitored.
   c. Unattended openings that intersect a security boundary, such as underground pathways, will be protected by a physical barrier and monitored by intrusion detection equipment or provided surveillance at a frequency sufficient to detect exploitation.
3. Isolation Zone:
   a. Isolation zones will exist in outdoor areas adjacent to the physical barrier at the perimeter of the protected area and will be designed of sufficient size to permit observation and assessment on either side of the barrier.
   b. Isolation zones will be monitored with intrusion detection and assessment equipment that is designed to provide detection and assessment of activities within the isolation zone.
   c. Areas where permanent buildings do not allow sufficient observation distance between the intrusion detection system and the protected area barrier (e.g., the building walls are immediately adjacent to, or are an integral part of the protected area barrier) will be monitored with intrusion detection and assessment equipment that is designed to detect the attempted or actual penetration of the protected area perimeter barrier before completed penetration of the barrier and assessment of detected activities.

4. Protected Area Perimeter Intrusion Detection and Assessment Systems:
    a. The perimeter intrusion detection system will be designed to detect penetration or attempted penetration of the protected area perimeter barrier before completed penetration of the barrier, and for subsequent alarms to annunciate concurrently in at least two continuously manned onsite alarm stations (central and secondary alarm stations).
    b. The perimeter assessment equipment will be designed to provide video image recording with real-time and playback capability that can provide assessment of detected activities before and after each alarm annunciation at the protected area perimeter barrier.
    c. The intrusion detection and assessment equipment at the protected area perimeter will be designed to remain operable from an uninterruptible power supply in the event of the loss of normal power.
5. Isolation zones and exterior areas within the protected area will be provided with illumination to permit assessment in the isolation zones and observation of activities within exterior areas of the protected area.
6. The external walls, doors, ceiling, and floors in the Secondary Alarm Station, and the last access control function for access to the protected area will be bullet resistant, to at least Underwriters Laboratories Ballistic Standard 752, “The Standard of Safety for Bullet-Resisting Equipment,” Level 4, or National Institute of Justice Standard 0108.01, “Ballistic Resistant Protective Materials,” Type III.
7. The vehicle barrier system will be designed, installed, and located at the necessary standoff distance to protect against the design-basis threat vehicle bombs.
8. Personnel, Vehicle, and Material Access Control Portals and Search Equipment:
    a. Access control points will be established and designed to control personnel and vehicle access into the protected area.
    b. Access control points will be established and designed with equipment for the detection of firearms, explosives, and incendiary devices at the protected area personnel access points.
9. An access control system with a numbered photo identification badge system will be installed and designed for use by individuals who are authorized access to protected areas and vital areas without escort.
10. Unoccupied vital areas will be designed with locking devices and intrusion detection devices that annunciate in the Secondary Alarm Station.
11. Alarm Station:
    a. Intrusion detection equipment and video assessment equipment will annunciate and be displayed concurrently in at least two continuously manned onsite alarm stations (Central and Secondary Alarm Stations).

b. The Secondary Alarm Station will be located inside the protected area and will be designed so that the interior of the alarm station is not visible from the perimeter of the protected area.

c. The alarm system will not allow the status of a detection point, locking mechanism or access control device to be changed without the knowledge and concurrence of the alarm station operator in the other alarm station.

d. Central and Secondary Alarm Stations will be designed, equipped and constructed such that no single act, in accordance with the design-basis threat of radiological sabotage, can simultaneously remove the ability of both the central and secondary alarm stations to 1) detect and assess alarms, 2) initiate and coordinate an adequate response to alarms, 3) summon offsite assistance, and 4) provide effective command and control.

e. Both the Central and Secondary Alarm Stations will be constructed, located, protected, and equipped to the standards for the Central Alarm Station (alarm stations need not be identical in design but shall be equal and redundant, capable of performing all functions required of alarm stations).

12. The secondary security power supply system for alarm annunciator equipment contained in the Secondary Alarm Station and non-portable communications equipment contained in the Secondary Alarm Station is located within a vital area.

13. Intrusion Detection Systems Console Display:

    a. Security alarm devices, including transmission lines to annunciators, will be tamper indicating and self-checking (e.g., an automatic indication is provided when failure of the alarm system or a component occurs or when on standby power), and alarm annunciation indicates the type of alarm (e.g., intrusion alarms, emergency exit alarm) and location.

    b. Intrusion detection and assessment systems will be designed to provide visual display and audible annunciation of alarms in the Secondary Alarm Station.

14. Intrusion detection systems recording equipment will record onsite security alarm annunciation including the location of the alarm, false alarm, alarm check, and tamper indication and the type of alarm, location, alarm circuit, date, and time.

15. Emergency exits through the protected area perimeter and vital area boundaries will be alarmed with intrusion detection devices and secured by locking devices that allow prompt egress during an emergency.

16. Communication:

    a. The Secondary Alarm Station will have conventional (land line) telephone service with the Main Control Room and local law enforcement authorities.

    b. The Secondary Alarm Station will be capable of continuous communication with on-duty security force personnel.

c. Non-portable communications equipment in the Secondary Alarm Station will remain operable from an independent power source in the event of loss of normal power.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.2.1-1 provides a definition of the inspections, tests and analysis, together with associated acceptance criteria for the site-specific portions of the physical security system.

Table 2.2.1-1 ITAAC for the Site-Specific Security System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1(a). Vital equipment will be located only within a vital area.	1(a). All vital equipment locations will be inspected.	1(a). Vital equipment is located only within a vital area.
1(b). Access to vital equipment will require passage through at least two physical barriers.	1(b). All vital equipment physical barriers will be inspected.	1(b). Vital equipment is located within a protected area such that access to the vital equipment requires passage through at least two physical barriers.
2(a). Physical barriers for the protected area perimeter will not be part of vital area barriers.	2(a). The protected area perimeter barriers will be inspected.	2(a). Physical barriers at the perimeter of the protected area are separated from any other barrier designated as a vital area barrier.
2(b). Penetrations through the protected area barrier will be secured and monitored.	2(b). All penetrations through the protected area barrier will be inspected.	2(b). All penetrations and openings through the protected area barrier are secured and monitored by intrusion detection equipment.
2(c). Unattended openings that intersect a security boundary, such as underground pathways, will be protected by a physical barrier and monitored by intrusion detection equipment or provided surveillance at a frequency sufficient to detect exploitation.	2(c). All unattended openings within the protected area barriers will be inspected.	2(c). All unattended openings (such as underground pathways) that intersect a security boundary (such as the protected area barrier), are protected by a physical barrier and monitored by intrusion detection equipment or provided surveillance at a frequency sufficient to detect exploitation.
3(a). Isolation zones will exist in outdoor areas adjacent to the physical barrier at the perimeter of the protected area and will be designed of sufficient size to permit observation and assessment on either side of the barrier.	3(a). The isolation zones in outdoor areas adjacent to the protected area perimeter barrier will be inspected.	3(a). The isolation zones exist in outdoor areas adjacent to the physical barrier at the perimeter of the protected area and are of sufficient size to permit observation and assessment of activities on either side of the barrier in the event of its penetration or attempted penetration.

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3(b). Isolation zones will be monitored with intrusion detection and assessment equipment that is designed to provide detection and assessment of activities within the isolation zone.	3(b). The intrusion detection equipment within the isolation zones will be inspected.	3(b). Isolation zones are equipped with intrusion detection and assessment equipment capable of providing detection and assessment of activities within the isolation zone.
3(c). Areas where permanent buildings do not allow sufficient observation distance between the intrusion detection system and the protected area barrier (e.g., the building walls are immediately adjacent to, or are an integral part of the protected area barrier) will be monitored with intrusion detection and assessment equipment that is designed to detect the attempted or actual penetration of the protected area perimeter barrier before completed penetration of the barrier and assessment of detected activities.	3(c). Inspections of areas of the protected area perimeter barrier that do not have isolation zones will be performed.	3(c). Areas where permanent buildings do not allow sufficient observation distance between the intrusion detection system and the protected area barrier (e.g., the building walls are immediately adjacent to, or an integral part of, the protected area barrier) are monitored with intrusion detection and assessment equipment that detects attempted or actual penetration of the protected area perimeter barrier before completed penetration of the barrier and assessment of detected activities.
4(a). The perimeter intrusion detection system will be designed to detect penetration or attempted penetration of the protected area perimeter barrier before completed penetration of the barrier, and for subsequent alarms to annunciate concurrently in at least two continuously manned onsite alarm stations (central and secondary alarm stations).	4(a). Tests, inspections, or a combination of tests and inspections of the intrusion detection system will be performed.	4(a). The intrusion detection system can detect penetration or attempted penetration of the protected area perimeter barrier before completed penetration of the barrier, and subsequent alarms annunciate concurrently in at least two continuously manned on site alarms stations (central and secondary alarm stations).

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4(b). The perimeter assessment equipment will be designed to provide video image recording with real-time and playback capability that can provide assessment of detected activities before and after each alarm annunciation at the protected area perimeter barrier.	4(b). Tests, inspections, or a combination of tests and inspections of the video assessment equipment will be performed.	4(b). The perimeter assessment equipment is capable of real-time and playback video image recording that provides assessment of detected activities before and after each alarm at the protected area perimeter barrier
4(c). The intrusion detection and assessment equipment at the protected area perimeter will be designed to remain operable from an uninterruptible power supply in the event of the loss of normal power.	4(c). Tests, inspections, or a combination of tests and inspections of the uninterruptible power supply will be performed.	4(c). All Intrusion detection and assessment equipment at the protected area perimeter remains operable from an uninterruptible power supply in the event of the loss of normal power.
5. Isolation zones and exterior areas within the protected area will be provided with illumination to permit assessment in the isolation zones and observation of activities within exterior areas of the protected area.	5. The illumination in isolation zones and exterior areas within the protected area will be inspected.	5. Illumination in isolation zones and exterior areas within the protected area is 0.2 foot candles measured horizontally at ground level or alternatively augmented, sufficient to permit assessment and observation.
6. The external walls, doors, ceiling, and floors in the Secondary Alarm Station, and the last access control function for access to the protected area will be bullet resistant, to at least Underwriters Laboratories Ballistic Standard 752, “The Standard of Safety for Bullet-Resisting Equipment,” Level 4, or National Institute of Justice Standard 0108.01, “Ballistic Resistant Protective Materials,” Type III.	6. Type test, analysis, or a combination of type test and analysis of the external walls, doors, ceiling, and floors in the Secondary Alarm Station, and the last access control function for access to the protected area will be performed.	6. A report exists and concludes that the walls, doors, ceilings, and floors in the Secondary Alarm Station, and the last access control function for access to the protected area are bullet resistant to at least Underwriters Laboratories Ballistic Standard 752, Level 4, or National Institute of Justice Standard 0108.01, Type III.

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The vehicle barrier system will be designed, installed, and located at the necessary standoff distance to protect against the design-basis threat vehicle bombs.	7. Type test, inspections, analysis or a combination of type tests, inspections, and analysis will be performed for the vehicle barrier system.	7. A report exists and concludes that the vehicle barrier system will protect against the threat vehicle bombs based on the standoff distance for the system.
8(a). Access control points will be established and designed to control personnel and vehicle access into the protected area.	8(a). Tests, inspections, or a combination of tests and inspections of installed systems and equipment will be performed.	8(a). Access control points exist for the protected area and are configured to control access.
8(b). Access control points will be established and designed with equipment for the detection of firearms, explosives, and incendiary devices at the protected area personnel access points.	8(b). Tests, inspections, or a combination of tests and inspections of installed systems and equipment will be performed.	8(b). Detection equipment exists and is capable of detecting firearms, explosives, and incendiary devices at the protected area personnel access control points.
9. An access control system with a numbered photo identification badge system will be installed and designed for use by individuals who are authorized access to protected areas and vital areas without escort.	9. The access control system and the numbered photo identification badge system will be tested.	9. The access authorization system with a numbered photo identification badge system is installed and provides authorized access to protected and vital areas only to those individuals with unescorted access authorization.
10. Unoccupied vital areas will be designed with locking devices and intrusion detection devices that annunciate in the Secondary Alarm Station.	10. Tests, inspections, or a combination of tests and inspections of unoccupied vital area intrusion detection equipment and locking devices will be performed.	10. Unoccupied vital areas are locked, and intrusion is detected and annunciated in the Secondary Alarm Station.
11(a). Intrusion detection equipment and video assessment equipment will annunciate and be displayed concurrently in at least two continuously manned onsite alarm stations (Central and Secondary Alarm Stations).	11(a). Tests, inspections, or a combination of tests and inspections of intrusion detection equipment and video assessment equipment will be performed.	11(a). Intrusion detection equipment and video assessment equipment annunciate and display concurrently in at least two continuously manned onsite alarm stations (Central and Secondary Alarm Stations).

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11(b). The Secondary Alarm Station will be located inside the protected area and will be designed so that the interior of the alarm station is not visible from the perimeter of the protected area.	11(b). The Secondary Alarm Station location will be inspected.	11(b). The Secondary Alarm Station is located inside the protected area, and the interior of the alarm station is not visible from the perimeter of the protected area.
11(c). The alarm system will not allow the status of a detection point, locking mechanism or access control device to be changed without the knowledge and concurrence of the alarm station operator in the other alarm station.	11(c). Tests, inspections, or a combination of tests and inspections of intrusion detection equipment and access control equipment will be performed.	11(c). The alarm system will not allow the status of a detection point, locking mechanism or access control device to be changed without the knowledge and concurrence of the alarm station operator in the other alarm station.
11(d). Central and Secondary Alarm Stations will be designed, equipped and constructed such that no single act, in accordance with the design-basis threat of radiological sabotage, can simultaneously remove the ability of both the central and secondary alarm stations to 1) detect and assess alarms, 2) initiate and coordinate an adequate response to alarms, 3) summon offsite assistance, and 4) provide effective command and control.	11(d). Tests, inspections, or a combination of tests and inspections of the Central and Secondary Alarm Stations will be performed.	11(d). Central and Secondary Alarm Stations are designed, equipped, and constructed such that no single act, in accordance with the design-basis threat of radiological sabotage, can simultaneously remove the ability of both the central and secondary alarm stations to 1) detect and assess alarms, 2) initiate and coordinate an adequate response to alarms, 3) summon offsite assistance, and 4) provide effective command and control.

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11(e). Both the Central and Secondary Alarm Stations will be constructed, located, protected, and equipped to the standards for the Central Alarm Station (alarm stations need not be identical in design but shall be equal and redundant, capable of performing all functions required of alarm stations).	11(e). Tests, inspections, or a combination of tests and inspections of the Central and Secondary Alarm Stations will be performed.	11(e). The Central and Secondary Alarm Stations are located, constructed, protected, and equipped to the standards of the Central Alarm Station and are functionally redundant (stations need not be identical in design).
12. The secondary security power supply system for alarm annunciator equipment contained in the Secondary Alarm Station and non-portable communications equipment contained in the Secondary Alarm Station is located within a vital area.	12. The secondary security power supply system will be inspected.	12. The secondary security power supply system for alarm annunciator equipment contained in the Secondary Alarm Station and non-portable communications equipment contained in the Secondary Alarm Station is located within a vital area.
13(a). Security alarm devices, including transmission lines to annunciators, will be tamper-indicating and self-checking (e.g., an automatic indication is provided when failure of the alarm system or a component occurs or when on standby power), and alarm annunciation indicates the type of alarm (e.g., intrusion alarms, emergency exit alarm) and location.	13(a). All security alarm devices and transmission lines will be tested.	13(a). Security alarm devices including transmission lines to annunciators are tamper-indicating and self-checking (e.g., an automatic indication is provided when failure of the alarm system or a component occurs, or when the system is on standby power), and the alarm annunciation indicates the type of alarm (e.g., intrusion alarm, emergency exit alarm) and location.

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
13(b). Intrusion detection and assessment systems will be designed to provide visual display and audible annunciation of alarms in the Secondary Alarm Station.	13(b). Intrusion detection and assessment systems will be tested.	13(b). The intrusion detection and assessment systems provide a visual display and audible annunciation of alarms in the Secondary Alarm Station (concurrently with the display and annunciation in the Central Alarm Station).
14. No Site-Specific ITAAC specified.	14. No Site-Specific ITAAC specified.	14. No Site-Specific ITAAC specified.
15. Emergency exits through the protected area perimeter and vital area boundaries will be alarmed with intrusion detection devices and secured by locking devices that allow prompt egress during an emergency.	15. Tests, inspections, or a combination of tests and inspections of emergency exits through the protected area perimeter and vital area boundaries will be performed.	15. Emergency exits through the protected area perimeter and vital area boundaries are alarmed with intrusion detection devices and secured by locking devices that allow prompt egress during an emergency.
16(a). The Secondary Alarm Station will have conventional (land line) telephone service with the Main Control Room and local law enforcement authorities.	16(a). Tests, inspections, or a combination of tests and inspections of the Secondary Alarm Stations' conventional (land line) telephone service will be performed.	16(a). The Secondary Alarm Station is equipped with conventional (land line) telephone service with the Main Control Room and local law enforcement authorities.
16(b). The Secondary Alarm Station will be capable of continuous communication with on-duty security force personnel.	16(b). Tests, inspections, or a combination of tests and inspections of the Secondary Alarm Stations' continuous communication capabilities will be performed.	16(b). The Secondary Alarm Station is capable of continuous communication with on-duty watchmen, armed security officers, armed responders, or other security personnel who have responsibilities within the physical protection program and during contingency response events.

Table 2.2.1-1 ITAAC for the Site-Specific Security System *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
16(c). Non-portable communications equipment in the Secondary Alarm Station will remain operable from an independent power source in the event of loss of normal power.	16(c). Tests, inspections, or a combination of tests and inspections of the non-portable communications equipment will be performed.	16(c). All non-portable communication devices (including conventional telephone systems) in the Secondary Alarm Station are wired to an independent power supply that enables those systems to remain operable (without disruption) during the loss of normal power.

2.3 Emergency planning ITAAC

The Emergency Planning ITAAC are provided in Table 2.3-1.

Table 2.3-1 ITAAC For Emergency Planning

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
1.0 Emergency Classification System			
10 CFR 50.47(b)(4) – A standard emergency classification and action level scheme, the bases of which include facility system and effluent parameters, is in use by the nuclear facility licensee, and State and local response plans call for reliance on information provided by facility licensees for determinations of minimum initial offsite response measures.	1.1 A standard emergency classification and emergency action level (EAL) scheme exists, and identifies facility system and effluent parameters constituting the bases for the classification scheme. [D.1**] [**D.1 corresponds to NUREG-0654 /FEMA-REP-1 evaluation criteria.] **ITAAC element addressed in:** COL EP II.D.1	1.1 An inspection of the control room, technical support center (TSC), and emergency operations facility (EOF) will be performed to verify that they have displays for retrieving facility system and effluent parameters that constitute the bases for the classification scheme identified in the Emergency Plan Implementing Procedures (EPIPs).	1.1.1 The specific parameters identified in the EAL thresholds listed in the EPIPs have been retrieved and displayed in the control room, TSC, and EOF. 1.1.2 The ranges available in the control room, TSC, and EOF encompass the values for the specific parameters identified in the EAL thresholds listed in the EPIPs.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
2.0 Notification Methods and Procedures			
10 CFR 50.47(b)(5) – Procedures have been established for notification, by the licensee, of State and local response organizations and for notification of emergency personnel by all organizations; the content of initial and follow-up messages to response organizations and the public has been established; and means to provide early notification and clear instruction to the populace within the plume exposure pathway Emergency Planning Zone have been established.	2.1 The means exist to notify responsible State and local organizations within 15 minutes after the licensee declares an emergency. [E.1] **ITAAC element addressed in:** COL EP II.E.1	2.1 A test will be performed of the capabilities.	2.1 A means to notify responsible organizations, within 15 minutes after the licensee declares an emergency, has been established via the Operational Hot Line among the control room, the Commonwealth of Virginia, Caroline County, Hanover County, Louisa County, Orange County, and Spotsylvania County.
	2.2 The means exist to notify emergency response personnel. [E.2] **ITAAC element addressed in:** COL EP II.E.2	2.2 A test will be performed of the capabilities.	2.2 A means exists to notify the NAPS Unit 3 emergency response organization.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
2.0 Notification Methods and Procedures (continued)			
	2.3 The means exist to notify and provide instructions to the populace within the plume exposure EPZ. [E.6] **ITAAC element addressed in:** COL EP II.E.6	2.3 The full test of notification capabilities will be conducted.	2.3 A means exists to notify and provide instructions to the public in accordance with the emergency plan requirements.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
3.0 Emergency Communications			
10 CFR 50.47(b)(6) – Provisions exist for prompt communications among principal response organizations to emergency personnel and to the public.	3.1 The means exist for communications among the control room, TSC, EOF, principal State and local emergency operations centers (EOCs), and radiological field assessment teams. [F.1.d] **ITAAC element addressed in:** COL EP II.F.1.d	3.1 A test will be performed of the capabilities.	3.1.1 Communications have been established between the control room and TSC. 3.1.2 Communications have been established among the control room, TSC, and EOF. 3.1.3 Communications via the Operational Hot Line have been established among the TSC and EOCs, which include the Commonwealth of Virginia, Caroline County, Hanover County, Louisa County, Orange County, and Spotsylvania County. 3.1.4 Communications have been established between the TSC and radiological monitoring teams. 3.1.5 Communications have been established between the EOF and radiological monitoring teams.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
3.0 Emergency Communications (continued)			
	3.2 The means exist for communications from the control room, TSC, and EOF to the NRC headquarters and regional office EOCs (including establishment of the Emergency Response Data System (ERDS) between the onsite computer system and the NRC Operations Center.) [F.1.f] **ITAAC element addressed in:** COL EP II.F.1.f	3.2 A test will be performed of the capabilities.	3.2 Communications have been established from the control room, TSC, and EOF to the NRC headquarters and Region II EOCs and an access port for ERDS is provided.
4.0 Public Education and Information			
[Deleted]	[Deleted]	[Deleted]	[Deleted]

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
5.0 Emergency Facilities and Equipment			
10 CFR 50.47(b)(8) – Adequate emergency facilities and equipment to support the emergency response are provided and maintained.	5.1 The licensee has established a technical support center (TSC) and onsite operational support center (OSC). [H.1] **ITAAC element addressed in:** COL EP II.H.1	5.1 An inspection of the as-built TSC and OSC will be performed.	5.1.1 The TSC has at least 1950 square feet of floor space. 5.1.2 The following communications equipment have been provided in the TSC and voice transmission and reception have been accomplished: • NRC systems: Emergency Notification System (ENS), Health Physics Network (HPN), Reactor Safety Counterpart Link (RSCL), Protective Measures Counterpart Link (PMCL), Management Counterpart Link (MCL) • Dedicated telephone to EOF • Dedicated telephone to control room • Dedicated telephone to OSC

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
5.0 Emergency Facilities and Equipment (continued)			
			5.1.3 The TSC has been located in the Electrical Building. 5.1.4 The TSC includes radiation monitors and a ventilation system with a high efficiency particulate air (HEPA) and charcoal filter. 5.1.5 A back-up electrical power supply is available for the TSC. 5.1.6 The OSC is in a location separate from the control room. 5.1.7 The following communications equipment have been provided in the OSC and voice transmission and reception have been accomplished: • Dedicated telephone to control room • Dedicated telephone to TSC • Plant page system (voice transmission only)

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
5.0 Emergency Facilities and Equipment (continued)			
	5.2 The licensee has established an emergency operations facility (EOF). [H.2] **ITAAC element addressed in:** COL EP II.H.2	5.2 An inspection of the EOF will be performed.	5.2.1 A report exists that confirms the EOF has at least 243 square meters (2,625 square feet). 5.2.2 Voice transmission and reception have been accomplished between the EOF and TSC. 5.2.3 A report exists that confirms voice transmission and reception have been accomplished via the Operational Hot Line among the EOF, Commonwealth of Virginia, Caroline County, Hanover County, Louisa County, Orange County, and Spotsylvania County. 5.2.4 The EOF has the means to acquire, display and evaluate radiological, meteorological, and plant system data pertinent to determining offsite protective measures.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment			
10 CFR 50.47(b)(9) – Adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use.	6.1 The means exist to provide initial and continuing radiological assessment throughout the course of an accident. [I.2] **ITAAC element addressed in:** COL EP II.I.2, Appendix 2	6.1 A test of the emergency plan will be conducted by performing an exercise or drill to verify the capability to perform accident assessment.	6.1 An exercise or drill has been accomplished, including use of selected monitoring parameters identified in the EAL thresholds listed in the EPIPs, to assess simulated degraded plant conditions and initiate protective actions in accordance with the following criteria: A. Accident Assessment and Classification 1. Initiating conditions identified, EAL parameters determined, and the emergency correctly classified throughout the drill. 2. Protective action recommendations developed and communicated to appropriate authorities.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment (continued)			
			B. Radiological Assessment and Control 1. Onsite radiological surveys performed and samples collected. 2. Radiation exposure of emergency workers monitored and controlled. 3. Field monitoring teams assembled and deployed. 4. Field team data collected and disseminated. 5. Dose projections developed. 6. The decision whether to issue radioprotective drugs to NAPS emergency workers made.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment (continued)			
	6.2 The means exist to determine the source term of releases of radioactive material within plant systems, and the magnitude of the release of radioactive materials based on plant system parameters and effluent monitors. [I.3] **ITAAC element addressed in:** COL EP II.I.3, Appendix 2	6.2 An analysis of emergency plan implementing procedures (EPIPs) and the Offsite Dose Calculation Manual (ODCM) will be completed to verify the ability to determine the source term and magnitude of release.	6.2 The EPIPs and ODCM correctly calculate source terms and magnitudes of postulated releases.
	6.3 The means exist to continuously assess the impact of the release of radioactive materials to the environment, accounting for the relationship between effluent monitor readings, and onsite and offsite exposures and contamination for various meteorological conditions. [I.4] **ITAAC element addressed in:** COL EP II.I.4, Appendix 2	6.3 An analysis of emergency plan implementing procedures (EPIPs) and the Offsite Dose Calculation Manual (ODCM) will be completed to verify the relationship between effluent monitor readings and offsite exposures and contamination for various meteorological conditions has been established.	6.3 The EPIPs and the ODCM calculate the relationship between effluent monitor readings and offsite exposures and contamination for various meteorological conditions.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment (continued)			
	6.4 The means exist to acquire and evaluate meteorological information. [I.5] **ITAAC element addressed in:** COL EP II.I.5	6.4 An inspection of the control room, TSC, and EOF will be performed to verify the availability of the following meteorological data: • Wind speed (at 10 m and 48.4 m) • Wind direction (at 10 m and 48.4 m) • Ambient air temperature (at 10 m) • Differential air temperature (between 10 m and 48.4 m)	6.4 The following meteorological data is available in the control room, TSC, and EOF: • Wind speed (at 10 m and 48.4 m) • Wind direction (at 10 m and 48.4 m) • Ambient air temperature (at 10 m) • Differential air temperature (between 10 m and 48.4 m)

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment (continued)			
	6.5 The means exist to make rapid assessments of actual or potential magnitude and locations of any radiological hazards through liquid or gaseous release pathways, including activation, notification means, field team composition, transportation, communication, monitoring equipment, and estimated deployment times. [I.8] **ITAAC element addressed in:** COL EP II.I.8	6.5 A test will be performed of the capabilities.	6.5 Demonstrate the capability for making rapid assessment of the actual or potential magnitude and locations of any radiological hazards through liquid or gaseous release pathways.
	6.6 The capability exists to detect and measure radioiodine concentrations in air in the plume exposure EPZ, as low as 10-7 µCi/cc (microcuries per cubic centimeter) under field conditions. [I.9] **ITAAC element addressed in:** COL EP II.I.9	6.6 A test of NAPS field survey instrumentation will be performed to verify the capability to detect airborne concentrations as low as 1E-07 microcuries per cubic centimeter.	6.6 Instrumentation used for monitoring I-131 to detect airborne concentrations as low as 1E-07 microcuries per cubic centimeter has been provided.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
6.0 Accident Assessment (continued)			
	6.7 The means exist to estimate integrated dose from the projected and actual dose rates, and for comparing these estimates with the EPA protective action guides (PAGs). [I.10] **ITAAC element addressed in:** COL EP II.I.10, Appendix 2	6.7 An analysis of emergency plan implementing procedures will be performed to verify that a methodology is provided to establish means for relating contamination levels and airborne radioactivity levels to dose rates and gross radioactivity measurements for the following isotopes – Kr-88, Ru-106, I-131, I-132, I-133, I-134, I-135, Te-132, Xe-133, Xe-135, Cs-134, Cs-137, Ce-144.	6.7 A report exists and concludes a methodology has been established for relating contamination levels and airborne radioactivity levels to dose rates and gross radioactivity measurements for the specified isotopes (Kr-88, Ru-106, I-131, I-132, I-133, I-134, I-135, Te-132, Xe-133, Xe-135, Cs-134, Cs-137, Ce-144), and for comparing the dose estimates with the EPA PAGs.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
7.0 Protective Response			
10 CFR 50.47(b)(10) – A range of protective actions has been developed for the plume exposure EPZ for emergency workers and the public. In developing this range of actions, consideration has been given to evacuation, sheltering, and, as a supplement to these, the prophylactic use of potassium iodide (KI), as appropriate. Guidelines for the choice of protective actions during an emergency, consistent with Federal guidance, are developed and in place, and protective actions for the ingestion exposure EPZ appropriate to the locale have been developed.	7.1 The means exist to warn and advise onsite individuals of an emergency, including those in areas controlled by the operator, including: [J.1] a. employees not having emergency assignments; b. visitors; c. contractor and construction personnel; and d. other persons who may be in the public access areas, on or passing through the site, or within the owner controlled area. **ITAAC element addressed in:** COL EP II.J.1	7.1 A test of the onsite warning and communications capability will be performed during a drill or exercise.	7.1.1 During a drill or exercise, notification and instructions were provided to onsite workers and visitors, within the Protected Area, over the plant public announcement system. 7.1.2 During a drill or exercise, audible warnings were provided to individuals outside the Protected Area, but within the Owner Controlled Area.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills			
10 CFR 50.47(b)(14) – Periodic exercises are (will be) conducted to evaluate major portions of emergency response capabilities, periodic drills are (will be) conducted to develop and maintain key skills, and deficiencies identified as a result of exercises or drills are (will be) corrected.	8.1 Licensee conducts a full-participation exercise to evaluate major portions of emergency response capabilities, which includes participation by each State and local agency within the plume exposure EPZ, and each State within the ingestion control EPZ. [N.1] **ITAAC element addressed in:** COL EP II.N.1	8.1 A full-participation exercise (test) will be conducted within the specified time periods of Appendix E to 10 CFR Part 50.	8.1.1 The exercise is completed within the specified time periods of 10 CFR 50, Appendix E, and a report exists that confirms onsite exercise objectives listed below have been met and there are no uncorrected onsite exercise deficiencies. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) A. Accident Assessment and Classification 1. Demonstrate the ability to identify initiating conditions, determine emergency action level (EAL) parameters, and correctly classify the emergency throughout the exercise. Standard Criteria: a. Determine the correct highest emergency classification level based on events which were in progress, considering past events and their impact on the current conditions, within 15 minutes from the time the initiating condition(s) or EAL(s) is (are) identified. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) B. Notifications 1. Demonstrate the ability to alert, notify, and mobilize site emergency response personnel. Standard Criteria: a. Initiate activation of the emergency recall system following initial event classification for an Alert or higher. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 2. Demonstrate the ability to notify responsible State and local government agencies within 15 minutes and the NRC within 60 minutes after declaring an emergency. a. Initiate transmittal of initial information to the Commonwealth of Virginia and risk jurisdictions using the designated emergency plan implementing procedure (EPIP) within 15 minutes of event classification. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) b. Initiate transmittal of follow-up information to the Commonwealth of Virginia and risk jurisdictions using the designated EPIP within appropriate interval. c. Initiate transmittal of initial information to the Nuclear Regulatory Commission (NRC) using the designated EPIP within 60 minutes of event classification. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 3. Demonstrate the ability to warn or advise onsite individuals of emergency conditions. Standard Criteria: a. Initiate notification of onsite individuals (via plant page or telephone), using the designated EPIP within 15 minutes of notification.
			4. Demonstrate the capability of the Alert and Notification System (ANS) sirens to operate properly when required. Standard Criteria: a. 90% of the sirens operate properly. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) C. Emergency Response 1. Demonstrate the capability to direct and control emergency operations. Standard Criteria: a. Command and control is demonstrated by the control room in the early phase of the emergency and the technical support center (TSC), after its activation. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 2. Demonstrate the ability to transfer emergency direction from the control room (simulator) to the TSC. Standard Criteria: a. Briefings were conducted prior to turnover responsibility. Personnel document transfer of duties. 3. Demonstrate the ability to prepare for around-the-clock staffing requirements. Standard Criteria: a. Complete 24-hour staff assignments. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 4. Demonstrate the ability to perform assembly and accountability for all onsite individuals during an emergency requiring protected area assembly and accountability. Standard Criteria: a. Protected area personnel assembly and accountability completed within 30 minutes following initiation of assembly and accountability measures. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) D. Emergency Response Facilities 1. Demonstrate activation of the operational support center (OSC), and full functional operation of the TSC and emergency operations facility (EOF). Standard Criteria: a. The TSC, OSC, and EOF are activated within about 60 minutes of the initial notification. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 2. Demonstrate the adequacy of equipment, security provisions, and habitability precautions for the TSC, OSC, EOF, and joint information center (JIC), as appropriate. Standard Criteria: a. Demonstrate the adequacy of the emergency equipment in the emergency response facilities. b. The *Security Team Leader* implements and follows applicable EPIPs. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) c. The Health Physics (HP) personnel implement the designated EPIP provisions if an onsite or offsite release has occurred. 3. Demonstrate the adequacy of communications for all emergency support resources. Standard Criteria: a. Emergency response facility personnel are able to operate all specified communication systems. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) b. Clear primary or backup communications links are established and maintained for the duration of the exercise. E. Radiological Assessment and Control 1. Demonstrate the ability to obtain onsite radiological surveys and samples. Standard Criteria: a. HP personnel demonstrate the ability to obtain appropriate instruments (range and type) and take surveys. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) b. Airborne samples are taken when the conditions indicate the need for the information. 2. Demonstrate the ability to continuously monitor and control radiation exposure to emergency workers. Standard Criteria: a. Emergency workers are issued selfreading dosimeters when radiation levels require, and exposures are controlled to 10 CFR 20 occupational dose limits (unless the Emergency Coordinator/EOF Director authorizes emergency limits). *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) b. Exposure records are available. c. Emergency workers include Security and personnel within all emergency facilities. 3. Demonstrate the ability to assemble and deploy field monitoring teams. Standard Criteria: a. One field monitoring team is ready to be deployed within 60 minutes of being requested, and no later than 90 minutes from the declaration of an Alert or higher emergency. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 4. Demonstrate the ability to satisfactorily collect and disseminate field team data. Standard Criteria: a. Field team data to be collected is dose rate or counts per minute (cpm) from the plume, both open and closed window, and air sample (gross/net cpm) for particulate and iodine, if applicable. b. Satisfactory data dissemination is from the field team to HP (*Plume Tracking/ Dose Assessment*) personnel. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 5. Demonstrate the ability to develop dose projections. Standard Criteria: a. Timely and accurate dose projections are performed in accordance with EPIPs. 6. Demonstrate the ability to make the decision whether to issue radioprotective drugs to emergency workers. Standard Criteria: a. Radioprotective drugs are taken (simulated) if the estimated dose to the thyroid will exceed 25 rem committed dose equivalent (CDE). *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 7. Demonstrate the ability to develop appropriate protective action recommendation(s) (PAR(s)) and notify appropriate authorities within 15 minutes of development. Standard Criteria: a. Total effective dose equivalent (TEDE) and CDE dose projections from the dose assessment computer code are compared to criteria in EPIPs. b. PAR(s) is (are) developed within 15 minutes of data availability, as appropriate. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) c. PAR(s) is (are) transmitted to responsible State and local government agencies within 15 minutes of development. F. Public Information 1. Demonstrate the capability to develop and disseminate clear, accurate, and timely information to the news media. Standard Criteria: a. Media information (e.g., press releases, press briefings, electronic media) is made available following notification of Dominion External Affairs personnel. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) 2. Demonstrate the capability to establish and effectively operate rumor control in a coordinated fashion. Standard Criteria: a. Calls are answered in a timely manner with the correct information. b. Rumors are identified and addressed. *(continued)*

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.1 (continued) G. Evaluation 1. Demonstrate the ability to conduct a post-exercise critique, to determine areas requiring improvement and corrective action. Standard Criteria: a. An exercise time-line is developed, followed by an evaluation of the objectives. b. Significant problems in achieving the objectives are discussed to ensure understanding of why objectives were not fully achieved. c. Recommendations for improvement in non-objective areas are discussed.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
8.0 Exercises and Drills (continued)			
			8.1.2 Onsite emergency response personnel are mobilized in sufficient number to fill the emergency positions identified in COL EP II.B, Onsite Emergency Organization, and a report exists that confirms they successfully perform their assigned responsibilities as outlined in Acceptance Criterion 8.1.1.D, Emergency Response Facilities.
			8.1.3 The exercise is completed within the specified time periods of 10 CFR 50, Appendix E, a report exists that confirms offsite exercise objectives have been met and there are no uncorrected offsite deficiencies, or a license condition requires offsite deficiencies to be corrected prior to operation above 5% of rated power.

Table 2.3-1 ITAAC For Emergency Planning *(continued)*

Planning Standard	EP Program Elements	Inspections, Tests, Analyses	Acceptance Criteria
9.0 Implementing Procedures			
10 CFR 50, Appendix E.V – No less than 180 days prior to the scheduled issuance of an operating license for a nuclear power reactor or a license to possess nuclear material, the applicant's detailed implementing procedures for its emergency plan shall be submitted to the Commission.	9.1 The licensee has submitted detailed implementing procedures for its emergency plan no less than 180 days prior to fuel load.	9.1 An inspection will be performed to confirm that the detailed implementing procedures for the Unit 3 Emergency Plan were submitted to the NRC.	9.1 Each of the detailed implementing procedures for the Unit 3 Emergency Plan, as defined in Appendix 5 of the Emergency Plan, are submitted to the NRC no less than 180 days prior to fuel load.

2.4 Site-Specific ITAAC

The Site Specific ITAAC are provided in the following sections. Site specific systems were evaluated against selection criteria in Section 14.3. If a site-specific system described in the FSAR does not meet an ITAAC selection criterion, only the system name and the statement “No entry for this system” is provided.

2.4.1 **ITAAC for Fill Concrete Under and Around the Sides of Seismic Category I Structures**

Compactible backfill will not be placed under Unit 3 Seismic Category I structures. ITAAC for fill concrete placed under and around the sides of Seismic Category I structures to a thickness greater than 5 feet are provided in Table 2.4.1-1.

Table 2.4.1-1 ITAAC for Fill Concrete Under and Around the Sides of Seismic Category I Structures

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The foundation grade for the FWSC will be established using fill concrete. Fill concrete placed under and around the sides of Seismic Category I Structures to a thickness greater than 5 feet is designed and tested as specified in FSAR Section 2.5.	Testing will be performed to determine the mean compressive strength for the fill concrete.	A report exists that demonstrates that the mean 28-day compressive strength of the fill concrete is equal to, or greater than, 17.2 MPa (2,500 psi).

2.4.2 ITAAC for Structural Fill Surrounding Seismic Category I Structures

Design Description

Structural fill surrounding the embedded walls for Seismic Category I structures meets properties for (1) the angle of internal friction; (2) the local effect on wall pressure as determined by the product of: peak ground acceleration α, (in g), Poisson's ratio ν, and density γ; and (3) soil density.

Inspections, Test, Analyses and Acceptance Criteria

Table 2.4.2-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Structural Fill.

Table 2.4.2-1 ITAAC for Structural Fill Surrounding Seismic Category I Structures

Design Commitment	Inspections, Tests, and Analyses	Acceptance Criteria
1. The structural fill material surrounding Seismic Category I structures meets the following properties: • the angle of internal friction ≥ 35 degrees • the local effect on wall lateral pressures ≤ 1220 kg/m^3 (76 lbf/ft^3), as determined by the following equation: $\alpha(0.95\nu + 0.65)\gamma$ where: α = peak ground acceleration (in g) ν = Poisson's ratio γ = density • the soil density $\gamma \geq 2000$ kg/m^3 (125 lbf/ft^3).	Tests, inspections, analyses, or a combination thereof, will be performed to evaluate the properties of the structural fill.	A report exists and concludes that the tests, inspections, analyses, or a combination thereof, confirm that the structural fill material surrounding Seismic Category I structures meets the following properties: • the angle of internal friction ≥ 35 degrees • the local effect on wall lateral pressures ≤ 1220 kg/m^3 (76 lbf/ft^3), as determined by the following equation: $\alpha(0.95\nu + 0.65)\gamma$ where: α = peak ground acceleration (in g) ν = Poisson's ratio γ = density • the soil density $\gamma \geq 2000$ kg/m^3 (125 lbf/ft^3).

2.4.3 ITAAC FOR Plant Service Water System (portion outside the scope of the certified design)

Design Description

The Plant Service Water System (PSWS) is the heat sink for the Reactor Component Cooling Water System. The PSWS does not perform any safety-related function. There is no interface with any safety-related component.

The PSWS cooling towers and basin are not within the scope of the certified design. A specific design for this portion of the PSWS is described in FSAR Section 9.2.1. Interface requirements are necessary for supporting the post-72-hour cooling function of the PSWS. The plant-specific portion of the PSWS shall meet the following interface requirement:

> The volume of water shall be sufficient such that no active makeup shall be necessary to remove $2.02x10^7$ MJ ($1.92x10^{10}$ BTU) over a period of seven days. Additionally, the PSWS pumps must have sufficient available net positive suction head at the pump suction location for the lowest probable water level of the heat sink.

Inspections, Test, Analyses and Acceptance Criteria

Table 2.4.3-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the PSWS.

Table 2.4.3-1 ITAAC for Plant Service Water Reserve Storage Capacity

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The volume of water in the PSWS basin shall be sufficient such that:		
a. No active makeup shall be necessary to remove 2.02×10^7 MJ (1.92×10^{10} BTU) over a period of seven days.	Inspections and analysis will be performed of the PSWS basin and cooling towers.	A report exists and concludes that the volume of water in the PSWS basin is sufficient such that no active makeup is necessary to remove 2.02×10^7 MJ (1.92×10^{10} BTU) over a period of seven days.
b. The PSWS pumps must have sufficient available net positive suction head at the pump suction location for the lowest probable water level of the heat sink.	Inspections and analysis will be performed of the PSWS basin.	A report exists and concludes that the PSWS pumps have sufficient available net positive suction head at the pump suction location for the lowest probable water level of the heat sink.

2.4.4 Circulating Water System (portion outside the scope of the certified design)

No ITAAC are required for this system.

2.4.5 Station Water System (including intake structure and servicing equipment)

No ITAAC are required for this system.

2.4.6 Yard Fire Protection System (portions outside scope of certified design)

No ITAAC are required for this system.

2.4.7 Potable & Sanitary Water Systems

No ITAAC are required for this system.

2.4.8 Offsite Power Systems

Design Description

The offsite portion of the Preferred Power Supply (PPS) consists of at least two electrical circuits and associated equipment that are used to interconnect the offsite transmission system with the plant main generator and the onsite portions of the PPS. The PPS consists of the normal preferred and alternate preferred power sources and includes those portions of the offsite power system and the onsite power system required for power flow from the offsite transmission system to the safety-related Isolation Power Centers (IPC) incoming line breakers.

The interface between the normal preferred ESBWR certified plant onsite portion of the PPS and the site-specific offsite portion of the PPS is at the switchyard side terminals of the high side motor operated disconnects (MODs) of the UAT circuit breaker and main generator circuit breaker. The interface between the alternate preferred ESBWR certified plant onsite portion of the PPS and the site specific offsite portion of the PPS is at the switchyard side terminals of the RAT high side MODs.

The as-built offsite portion of the PPS, from the transmission network to the interface with the onsite portions of the PPS, satisfies the applicable provisions of GDC 17. Specifically, the offsite portion of the PPS shall meet the following interface requirements:

1. At least two independent circuits supply electric power from the transmission network to the interface with the onsite portions of the PPS.
2. Each offsite circuit interfacing with the onsite portions of the PPS is adequately rated to supply the load requirements during design basis operating modes (refer to DCD ITAAC 2.13.1-2, Item 9).
3. Under normal steady state operation of the transmission system, the offsite portion of the PPS is capable of supplying voltage at the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.

4. Under normal steady state operation of the transmission system, the offsite portion of the PPS is capable of supplying required frequency at the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.
5. The fault current contribution of the offsite portion of the PPS is compatible with the interrupting capability of the onsite fault current interrupting devices.

Inspections, Test, Analyses and Acceptance Criteria

Table 2.4.8-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Offsite Power Systems.

Table 2.4.8-1 ITAAC for Offsite Power Systems

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Independent offsite power sources supply electric power from the transmission network to the interface with the onsite PPS.		
a. A minimum of two offsite power circuits are provided to the interface with the onsite PPS and are physically separate.	a. Inspections of the as-built offsite power supply transmission system will be performed.	a. A report exists and concludes the following inspection results: i) At least two offsite transmission circuits are provided to the interface with the onsite PPS. ii) The two offsite power circuits are physically separated by distance or physical barriers so as to minimize to the extent practical the likelihood of their simultaneous failure under design basis conditions. iii) The two offsite power circuits do not have a common takeoff structure or use a common structure for support.
b. The two offsite power circuits interfacing with the onsite PPS are electrically independent.	b. Test of the as-built offsite power system will be conducted by providing a test signal in only one offsite power circuit at a time.	b. A report exists and concludes that a test signal exists in only the circuit under test.
c. The breaker control power, instrumentation, and control circuits for the two offsite power circuits interfacing with the onsite PPS are electrically independent.	c. Tests of the as-built offsite breaker control power, instrumentation, and control circuits will be conducted by providing a test signal in only one offsite power circuit at a time.	c. A report exists and concludes that a test signal exists in only the circuit under test.

Table 2.4.8-1 ITAAC for Offsite Power Systems *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. At least two offsite power circuits interfacing with the onsite portions of the PPS are each adequately rated to supply necessary load requirements during design basis operating modes.	2. Analyses of the offsite power system will be performed to evaluate the as-built ratings of each offsite power circuit interfacing with the onsite portions of the PPS against the load requirements determined in DCD ITAAC 2.13.1-2, Item 9.	2. A report exists and concludes that at least two offsite power circuits from the transmission network up to the interface with the onsite portions of the PPS are each rated to supply the load requirements, during design basis operating modes, of their respective safety-related and nonsafety-related load groups.
3. Under normal steady state operation of the transmission system, the offsite portion of the PPS is capable of supplying required voltage to the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.	3. Analyses of the as-built offsite portion of the PPS will be performed to evaluate the capability of each offsite power circuit to supply the voltage requirements at the interface with the onsite portion of the PPS determined in DCD ITAAC 2.13.1-2, Item 9.	3. A report exists and concludes that as-built offsite portion of the PPS, under normal steady state operation of the transmission system, is capable of supplying voltage at the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.
4. Under normal steady state operation of the transmission system, the offsite portion of the PPS is capable of supplying required frequency to the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.	4. Analyses of the as-built offsite portion of the PPS will be performed to evaluate the capability of each offsite power circuit to supply the frequency requirements at the interface with the onsite portions of the PPS determined in DCD ITAAC 2.13.1-2, Item 9.	4. A report exists and concludes that as-built offsite portion of the PPS, under normal steady state operation of the transmission system, is capable of supplying required frequency at the interface with the onsite portions of the PPS that will support operation of safety-related loads during design basis operating modes.

Table 2.4.8-1 ITAAC for Offsite Power Systems *(continued)*

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The fault current contribution of the offsite portion of the PPS is compatible with the interrupting capability of the onsite short circuit interrupting devices.	5. Analyses of the as-built offsite portion of the PPS will be performed to evaluate the fault current contribution of each offsite power circuit at the interface with the onsite portions of the PPS.	5. A report exists and concludes the short circuit contribution of the as-built offsite portion of the PPS at the interface with the onsite portions of the PPS is compatible with the interrupting capability of the onsite fault current interrupting devices as determined in DCD ITAAC 2.13.1-2, Item 10.

2.4.9 Communications Systems (Emergency Notification System)

Addressed in Table 2.3-1, 3.0 Emergency Communications

2.4.10 Makeup Water System

No ITAAC are required for this system.

2.4.11 (Deleted)

2.4.12 (Deleted)

2.4.13 Hydrogen Water Chemistry System

No ITAAC are required for this system.

2.4.14 Meteorological Monitoring System

No ITAAC are required for this system.

2.4.15 ITAAC for the Turbine Building

Design Description

The Turbine Building is a Seismic Category II building. The Turbine Building analysis and design methodology is the same as that used for a Seismic Category I structure. DCD Tier 1 ITAAC Table 2.16.8-1, Item 1 defines the associated load combinations and is performed for the design and analysis of the Turbine Building according to the Unit 3 definition of the Safe Shutdown Earthquake. The design and analysis of the Turbine Building will preclude any adverse interaction with Seismic Category I structures, considering the soil properties. The Unit 3 seismic design response spectra are based on 5 percent damping of the free-field outcrop spectra at the foundation level (bottom of the base slab): 1) the scaled CSDRS shown in DCD Figures 2.0-1 and 2.0-2; and 2) the FIRS for each individual structure. Foundation input response spectra will be developed for the Turbine Building at the foundation level. Site-specific soil structure interaction (SSI) analyses using the Unit 3 seismic design response spectra and using site-specific soil properties will be performed for the Turbine Building following the same methodology used in FSAR Section 3.7.2 to determine SSI enveloping seismic loads and to develop in-structure response spectra. Site-specific structure-soil-structure interaction (SSSI) analyses are performed using the same methodology as for Seismic Category I SSSI analyses. The analyses use the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I Structures.

Inspections, Test, Analyses and Acceptance Criteria

Table 2.4.15-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Turbine Building.

Table 2.4.15-1 ITAAC for the Turbine Building

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The site-specific seismic load demands for the Turbine Building structure are within acceptable limits to ensure that the structure is seismically adequate, using the same analysis methodology as a Seismic Category I structure, considering associated loads as described in DCD Tier 1 ITAAC Table 2.16.8-1, Item 1.	Perform site-specific SSI analysis, following the methodology specified for Seismic Category I structures in FSAR Section 3.7.2, to address ground motion exceedances and site-specific effects of subgrade properties. If the Turbine Building structure seismic load demands exceed the standard design seismic loads, perform a structural design evaluation of the Turbine Building in the same manner as for a Seismic Category I structure, including the load combinations and the acceptance criteria, for the associated loads.	The Turbine Building structure seismic load demands obtained from the site-specific SSI analysis are acceptable if at least one of the following two criteria are satisfied: (1) the site-specific seismic loads are bounded by the standard design seismic loads used for the Turbine Building; or, (2) the results from the site-specific structural design evaluation demonstrate that the Turbine Building total stresses are bounded by the Code allowable stress limits for a Seismic Category I structure, for the associated loads.
The SSI analysis uses site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings.		Site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology are used in the SSI analysis.
2. Seismic SSSI of the non-Seismic Category I Turbine Building will not impair the ability of the adjacent Seismic Category I Reactor Building to perform its safety functions.	Perform site-specific SSSI analyses to evaluate seismic interaction between the Turbine Building and adjacent Seismic Category I Reactor Building, using methodology consistent with that used for the Seismic Category I structures.	Site-specific analyses conclude that there is no seismic SSSI of the non-Seismic Category I Turbine Building that impairs the ability of the adjacent Seismic Category I Reactor Building to perform its safety functions.

2.4.16 ITAAC for the Radwaste Building

Design Description

The Radwaste Building is a Seismic Category NS building. The Radwaste Building is designed in accordance with RG 1.143 Classification RW-IIa, and for seismic, it is designed for full Safe Shutdown Earthquake. The method of analysis, including load combinations and acceptance criteria, is the same as that used for a Seismic Category I structure. DCD Tier 1 ITAAC Table 2.16.9-1, Item 1 defines the associated load combinations and is performed for the design and analysis of the Radwaste Building according to the site-specific Safe Shutdown Earthquake. The design and analysis of the Radwaste Building will preclude any adverse interaction with Seismic Category I structures, considering the soil properties.

The seismic design response spectra are based on 5% damping of the free-field outcrop spectra at the foundation level (bottom of the base slab): 1) the scaled CSDRS shown in DCD Figures 2.0-1 and 2.0-2; and 2) the FIRS for each individual structure. Foundation input response spectra will be developed for the Radwaste Building at the foundation level. Site-specific soil structure interaction (SSI) analyses using the seismic design response spectra and using site-specific soil properties will be performed for the Radwaste Building following the same methodology used in FSAR Section 3.7.2 to determine SSI enveloping seismic loads and to develop in-structure response spectra. Site-specific structure-soil-structure interaction (SSSI) analyses are performed using the same methodology as for Seismic Category I SSSI analyses. The analyses use the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I Structures. The Radwaste Building has an exterior static wall pressure capacity of at least 3 psi.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.16-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Radwaste Building.

Table 2.4.16-1 ITAAC for the Radwaste Building

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The site-specific seismic load demands for the Radwaste Building structure are within acceptable limits to ensure that the structure is seismically adequate, using the same analysis methodology as a Seismic Category I structure, considering associated loads as described in DCD Tier 1 ITAAC Table 2.16.9-1, Item 1.	Perform site-specific SSI analysis, following the methodology specified for Seismic Category I structures in FSAR Section 3.7.2, to address ground motion exceedances and site-specific effects of subgrade properties. If the Radwaste Building structure seismic load demands exceed the standard design seismic loads, perform a structural design evaluation of the Radwaste Building in the same manner as for a Seismic Category I structure, including the load combinations and the acceptance criteria, for the associated loads.	The Radwaste Building structure seismic load demands obtained from the site-specific SSI analysis for the Radwaste Building structure are acceptable if at least one of the following two criteria are satisfied: (1) the site-specific seismic loads are bounded by the standard design seismic loads used for the Radwaste Building; or, (2) the results from the site-specific structural evaluation demonstrate that the Radwaste Building total stresses are bounded by Code allowable stress limits that are the same as for a Seismic Category I structure, for the associated loads.
The SSI analysis uses site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings.		Site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology are used in the SSI analysis.
2. The Radwaste Building has an exterior wall static pressure capacity of at least 3 psi.	Perform an analysis to determine the static wall pressure capacity of the exterior walls of the as-built Radwaste Building.	Results of the Radwaste Building analysis demonstrate that the exterior wall static pressure capacity is at least 3 psi.

Table 2.4.16-1 ITAAC for the Radwaste Building *(continued)*

3. Seismic SSSI of the non-Seismic Category I Radwaste Building will not impair the ability of the adjacent Seismic Category I Reactor Building to perform its safety functions.	Perform site-specific SSSI analyses to evaluate seismic interaction between the Radwaste Building and adjacent Seismic Category I Reactor Building, using methodology consistent with that used for the Seismic Category I structures.	Site-specific analyses conclude that there is no seismic SSSI of the non-Seismic Category I Radwaste Building that impairs the ability of the adjacent Seismic Category I Reactor Building to perform its safety functions.

2.4.17 **ITAAC for the Service Building**

Design Description

The Service Building is a Seismic Category II building. The Service Building analysis and design methodology is the same as that used for a Seismic Category I structure. DCD Tier 1 ITAAC Table 2.16.10-1, Item 1 defines the associated load combinations and is performed for the design and analysis of the Service Building according to the site-specific Safe Shutdown Earthquake. The design and analysis of the Service Building will preclude any adverse interaction with Seismic Category I structures, considering the soil properties.

The seismic design response spectra are based on 5% damping of the free-field outcrop spectra at the foundation level (bottom of the base slab): 1) the scaled CSDRS shown in DCD Figures 2.0-1 and 2.0-2; and 2) the FIRS for each individual structure. Foundation input response spectra will be developed for the Service Building at the foundation level. Site-specific soil structure interaction (SSI) analyses using the seismic design response spectra and using site-specific soil properties will be performed for the Service Building following the same methodology used in FSAR Section 3.7.2 to determine SSI enveloping seismic loads and to develop in-structure response spectra. Site-specific structure-soil-structure interaction (SSSI) analyses are performed using the same methodology as for Seismic Category I SSSI analyses. The analyses use the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I Structures.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.17-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Service Building.

Table 2.4.17-1 ITAAC for the Service Building

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The site-specific seismic load demands for the Service Building structure are within acceptable limits to ensure that the structure is seismically adequate, using the same analysis methodology as a Seismic Category I structure, considering associated loads as described in DCD Tier 1 ITAAC Table 2.16.10-1, Item 1.	Perform site-specific SSI analysis, following the methodology specified for Seismic Category I structures in FSAR Section 3.7.2, to address ground motion exceedances and site-specific effects of subgrade properties. If the Service Building structure seismic load demands exceed the standard design seismic loads, perform a structural design evaluation of the Service Building in the same manner as for a Seismic Category I structure, including the load combinations and the acceptance criteria, for the associated loads.	The Service Building structure seismic load demands obtained from the site-specific SSI analysis are acceptable if at least one of the following two criteria are satisfied: (1) the site-specific seismic loads are bounded by the standard design seismic loads used for the Service Building; or, (2) the results from the site-specific structural design evaluation demonstrate that the Service Building total stresses are bounded by Code allowable stress limits that are the same as for a Seismic Category I structure, for the associated loads.
The SSI analysis uses site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings.		Site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology are used in the SSI analysis.
2. Seismic SSSI of the non-Seismic Category I Service Building will not impair the ability of the adjacent Seismic Category I Reactor Building, Control Building, Fuel Building, or FWSC to perform the safety functions.	Perform site-specific SSSI analyses to evaluate seismic interaction between the Service Building and adjacent Seismic Category I Reactor Building, Control Building, Fuel Building, or FWSC, using methodology consistent with that used for the Seismic Category I structures.	Site-specific analyses conclude that there is no seismic SSSI of the non-Seismic Category I Service Building that impairs the ability of the adjacent Seismic Category I Reactor Building, Control Building, Fuel Building, or FWSC to perform the safety functions.

2.4.18 ITAAC for the Ancillary Diesel Building

Design Description

The Ancillary Diesel Building is a Seismic Category II building. The Ancillary Diesel Building analysis and design methodology is the same as that used for a Seismic Category I structure. DCD Tier 1 ITAAC Table 2.16.11-1, Item 1 defines the associated load combinations and is performed for the design and analysis of the Ancillary Diesel Building according to the site-specific Safe Shutdown Earthquake. The design and analysis of the Ancillary Diesel Building will preclude any adverse interaction with Seismic Category I structures, considering the soil properties.

The seismic design response spectra are based on 5% damping of the free-field outcrop spectra at the foundation level (bottom of the base slab): 1) the scaled CSDRS shown in DCD Figures 2.0-1 and 2.0-2; and 2) the FIRS for each individual structure. Foundation input response spectra will be developed for the Ancillary Diesel Building at the foundation level. Site-specific soil structure interaction (SSI) analyses using the seismic design response spectra and using site-specific soil properties will be performed for the Ancillary Diesel Building following the same methodology used in FSAR Section 3.7.2 to determine SSI enveloping seismic loads and to develop in-structure response spectra. Site-specific structure-soil-structure interaction (SSSI) analyses are performed using the same methodology as for Seismic Category I SSSI analyses. The analyses use the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I Structures.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.18-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the Ancillary Diesel Building.

Table 2.4.18-1 ITAAC for the Ancillary Diesel Building

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The site-specific seismic load demands for the Ancillary Diesel Building structure are within acceptable limits to ensure that the structure is seismically adequate, using the same analysis methodology as a Seismic Category I structure, considering associated loads as described in DCD Tier 1 ITAAC Table 2.16.11-1, Item 1.	Perform site-specific SSI analysis, following the methodology specified for Seismic Category I structures in FSAR Section 3.7.2, to address ground motion exceedances and site-specific effects of subgrade properties. If the Ancillary Diesel Building structure seismic load demands exceed the standard design seismic loads, perform a structural design evaluation of the Ancillary Diesel Building in the same manner as for a Seismic Category I structure, including the load combinations and the acceptance criteria, for the associated loads.	The Ancillary Diesel Building structure seismic load demands obtained from the site-specific SSI analysis are acceptable if at least one of the following two criteria are satisfied: (1) the site-specific seismic loads are bounded by the standard design seismic loads used for the Ancillary Diesel Building; or, (2) the results from the site-specific structural design evaluation demonstrate that the total stresses are bounded by Code allowable stress limits that are the same as for a Seismic Category I structure, for the associated loads.
The SSI analysis uses site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings.		Site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology are used in the SSI analysis.
2. Seismic SSSI of the non-Seismic Category I Ancillary Diesel Building will not impair the ability of the adjacent Seismic Category I Fuel Building to perform its safety functions.	Perform site-specific SSSI analyses to evaluate seismic interaction between the Ancillary Diesel Building and adjacent Seismic Category I Fuel Building, using methodology consistent with that used for the Seismic Category I structures.	Site-specific analyses conclude that there is no seismic SSSI of the non-Seismic Category I Ancillary Diesel Building that impairs the ability of the adjacent Seismic Category I Fuel Building to perform its safety functions.

2.4.19 **ITAAC for the Control Rods**

Design Description

The control rods to be loaded into the initial core will be able to withstand seismic and dynamic loads under normal operation and design basis conditions.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.19-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the control rods.

Table 2.4.19-1 ITAAC for the Control Rods

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The control rods to be loaded into the initial core will be able to withstand seismic and dynamic loads under normal operation and design basis conditions.	An analysis of the control rods seismic and dynamic loads will be performed on the as-built control rods that will be loaded into the ESBWR initial core. The analysis will be performed using the same methodology as described in FSAR Reference 4.2-202.	The analyses of the seismic and dynamic loads on the as-built control rods conclude that: (1) stress and strain do not exceed the ultimate stress or strain limits of the material, structure, or welded connection as specified in FSAR Reference 4.2-202. (2) fatigue usage factor does not exceed 1.0. (3) the calculated maximum horizontal fuel channel oscillation amplitude limit in FSAR Reference 4.2-202 is met.

2.4.20 ITAAC for Seismic Category I Buried Piping, Conduits and Tunnels

Design Description

Buried Seismic Category I piping, conduit and tunnels are designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis. The site-specific SSE FIRS are developed using site-specific soil properties following the methodology used in FSAR Sections 2.5.2 and 3.7.1 to determine site-specific SSE FIRS for design of Seismic Category I buildings.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.20-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for buried Seismic Category I piping, conduit and tunnels.

Table 2.4.20-1 ITAAC for Seismic Category I Buried Piping, Conduits and Tunnels

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The buried Seismic Category I piping, conduit and tunnels are designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis. The SSI analysis uses site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings.	Unit 3 soil properties will be determined. Site-specific FIRS will be developed. Analysis of the as-built buried Seismic Category I piping, conduit and tunnels will be conducted.	The as-built buried Seismic Category I piping, conduit and tunnels are designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13. Site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology are used in the SSI analysis.

2.4.21 ITAAC for Access Tunnel

Design Description

The buried Seismic Category II Access Tunnel is designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis. The analysis uses the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings. Seismic gaps between the buried Seismic Category II Access Tunnel and the adjacent Seismic Category I RB/FB and CB structures are no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.21-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the buried Seismic Category II Access tunnel.

Table 2.4.21-1 ITAAC for Access Tunnel

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The buried Seismic Category II Access Tunnel is designed and constructed to accommodate the applicable dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis, using the same approach as Seismic Category I structures.	Site-specific soil properties and site-specific foundation input response spectra (FIRS) using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings are developed and used in the SSI analysis of the Access Tunnel. Analysis of the as-built Access Tunnel will be conducted using the same approach as the Seismic Category I structures	The as-built buried Seismic Category II Access Tunnel is designed and constructed to accommodate the applicable dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13 using the same approach as Seismic Category I structures.
2. Seismic gaps between the buried Seismic Category II Access Tunnel and the adjacent Seismic Category I RB/FB and CB structures are no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion.	(i) Analyses will be performed to determine the necessary size of the seismic gaps. (ii) Inspection of the size of the as-built seismic gaps will be performed	(i) Analyses determine and document a seismic gap size that is no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion. (ii) The inspected as-built seismic gaps are sized consistent with the analyzed size of the seismic gaps.

2.4.22 ITAAC for Radwaste Tunnel

Design Description

The buried Radwaste Tunnel is classified as non-seismic but the structural acceptance criteria are in accordance with RG 1.143, Safety Class RW-IIa, and using the RG 1.143 ½ Safe Shutdown Earthquake. The Radwaste Tunnel is designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis. The analysis uses the same approach as Seismic Category I structures for site-specific foundation input response spectra (FIRS) developed using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings. Seismic gaps between the buried RW-IIa Radwaste Tunnel and the adjacent Seismic Category I RB/FB structures are no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.22-1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria for the buried Radwaste Tunnel.

Table 2.4.22-1 ITAAC for Radwaste Tunnel

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The buried RW-IIa Radwaste Tunnel is designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13, which form the structural design basis, using the same approach as Seismic Category I structures.	Site-specific properties and site-specific foundation input response spectra (FIRS) using site-specific soil properties and FSAR Sections 2.5.2 and 3.7.1 methodology for Seismic Category I buildings are developed and used in the SSI analysis of the Radwaste Tunnel. Analysis of the as-built Radwaste Tunnel will be conducted using the same approach as the Seismic Category I structures.	The as-built buried RW-IIa Radwaste Tunnel is designed and constructed to accommodate the dynamic, static, and thermal loading conditions associated with the various loads and load combinations identified in FSAR Section 3.7.3.13 using the same approach as Seismic Category I structures.
2. Seismic gaps between the buried RW-IIa Radwaste Tunnel and the adjacent Seismic Category I Reactor Building structure are provided with no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion.	(i) Analyses will be performed to determine the necessary size of the seismic gaps. (ii) Inspection of the size of the as-built seismic gaps will be performed	(i) Analyses determine and document a seismic gap size that is no less than the calculated maximum relative displacement during an SSE event, considering out-of-phase motion. (ii) The inspected as-built seismic gaps are sized consistent with the analyzed size of the seismic gaps.

3. North Anna 3 Proposed License Conditions

3.1 Emergency Planning Actions

Prior to loading fuel, the licensee shall update its Units 1 & 2 Letters of Agreement with the following entities or their successors:

- Commonwealth of Virginia Department of Emergency Management
- Commonwealth of Virginia Department of Health
- Commonwealth of Virginia Department of State Police
- Commonwealth of Virginia Department of Game and Inland Fisheries
- Virginia Commonwealth University Medical Center
- Louisa County Administrator
- Louisa County Sheriff
- Louisa County Department of Fire and Emergency Medical Services
- Spotsylvania County Sheriff
- Spotsylvania Department of Fire, Rescue, and Emergency Management
- Orange County Administrator
- Orange County Sheriff
- Caroline County Sheriff
- Caroline County Department of Fire, Rescue, and Emergency Management
- Hanover County Administrator
- Hanover County Sheriff

These updated Letters of Agreement will identify the specific nature of arrangements in support of emergency preparedness for the North Anna Power Station site, including Unit 3. The Emergency Plan shall be revised to include these updated Letters of Agreement after they have been executed.

3.2 License Conditions for Initial Test Program

3.2.1 **Startup Administrative Manual, NAPS COL 14.2-2-A**

Prior to initiating the initial test program (ITP), a site-specific startup administration manual (SAM), which includes administrative procedures and requirements that govern the activities associated with the plant ITP, is to be provided to on-site NRC inspectors 60 days prior to the beginning of the preoperational test phase.

3.2.2 **Preoperational and Startup Test Procedures, NAPS COL 14.2-3-A**

The licensee will make available to on-site NRC inspectors preoperational test procedures 60 days prior to their intended use and startup test procedures 60 days prior to fuel load.

3.2.3 Site-Specific Preoperational and Startup Test Procedures, NAPS COL 14.2-6-A

The licensee will make available to on-site NRC inspectors site-specific preoperational test procedures 60 days prior to their intended use and startup test procedures 60 days prior to fuel load.

3.2.4 Power Ascension Test Phase Reports

3.2.4.1 Nuclear Fuel Loading and Pre-critical Testing

a. Upon notifying the Director of the Office of New Reactors (NRO), or the Director's designee, in writing of successful completion of preoperational testing, and upon a Commission finding in accordance with 10 CFR 52.103(g) that all the acceptance criteria in the ITAAC in Appendix C to this license are met, the licensee is authorized to perform pre-critical tests in accordance with the conditions specified herein.

b. The licensee shall review and evaluate the results of the pre-critical tests identified and confirm that these test results are within the range of acceptable values predicted or otherwise confirm that the tested systems perform their specified functions in accordance with the FSAR.

3.2.4.2 Initial Criticality and Low-Power Testing

a. Upon notifying the Director of NRO, or the Director's designee, in writing of successful completion of pre-critical testing, the licensee is authorized to operate the facility at reactor steady-state core power levels not to exceed 5-percent thermal power in accordance with the conditions specified herein, but solely for purposes of conducting initial criticality and low-power testing.

b. The licensee shall review and evaluate the results of the initial criticality and low-power tests and confirm that these test results are within the range of acceptable values predicted or otherwise confirm that the tested systems perform their specified functions in accordance with the FSAR.

3.2.4.3 Power Ascension Testing

a. Upon notifying the Director of NRO, or the Director's designee, in writing of successful completion of initial criticality and low-power testing, the licensee is authorized to operate the facility at reactor steady-state core power levels not to exceed 100-percent thermal power in accordance with the conditions specified herein, but only for the purpose of performing power ascension testing.

b. The licensee shall review and evaluate the results of the power ascension tests and confirm that these test results are within the range of acceptable values predicted or otherwise confirm that the tested systems perform their specified functions in accordance with the FSAR.

3.2.4.4 **Maximum Power Level**

Upon notifying the Director of NRO, or the Director's designee, in writing of successful completion of power ascension testing, the licensee is authorized to operate the facility at steady state reactor core power levels not to exceed 4500 MW thermal (100-percent thermal power), as described in the FSAR, in accordance with the conditions specified herein.

3.2.5 **Test Changes**

Within 30 days of a change to the initial test program described in FSAR Chapter 14, Initial Test Program, made in accordance with 10 CFR 50.59 or in accordance with 10 CFR 52, Appendix E, Section VIII, "Processes for Changes and Departures," the licensee shall report the change to the Director of NRO, or the Director's designee, in accordance with 10 CFR 50.59(d).

3.3 License Conditions for Byproduct, Source and Special Nuclear Material

Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

1. a. The licensee, pursuant to the Atomic Energy Act of 1954 (the Act) and 10 CFR 70, to receive and possess at any time, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, described in the FSAR, as supplemented and amended;
   b. The licensee, pursuant to the Act and 10 CFR 70, to use special nuclear material as reactor fuel, after a Commission 10 CFR 52.103(g) finding has been made, in accordance with the limitations for storage and amounts required for reactor operation, and described in the FSAR, as supplemented and amended;
2. The licensee, pursuant to the Act and 10 CFR 30, 10 CFR 40, and 10 CFR 70, to receive, possess, and use, at any time, any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;
3. The licensee, pursuant to the Act and 10 CFR 30, 10 CFR 40, and 10 CFR 70, to receive, possess, and use in amounts as required, any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and
4. The licensee, pursuant to the Act and 10 CFR 30 and 10 CFR 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3.4 Fire Protection Program Actions

Prior to the receipt of fuel on site, the licensee shall execute, or have in place, a formal Letter of Agreement with the Louisa County Department of Fire and Emergency Medical Services. This

Letter of Agreement will identify the specific nature of arrangements in support of the Fire Protection Program of Unit 3.

3.5 Operational Program Implementation

3.5.1 **18 months prior to Fuel Load**

The licensee shall implement the operational program identified below at least 18 months prior to the scheduled date of initial fuel load:

- Reactor Operator Training Program

3.5.2 **Receipt of Materials**

The licensee shall implement the operational programs identified below prior to initial receipt of byproduct, source, or special nuclear materials on site (excluding Exempt Quantities as described in 10 CFR 30.18):

- Radiation Protection Program (for elements necessary to support receipt of byproduct, source, or special nuclear materials on site)
- Fire Protection Program (for elements necessary to support receipt of byproduct, source, or special nuclear materials on site)

The licensee shall implement the operational program identified below prior to receipt of special nuclear material on site:

- SNM Material Control and Accounting Program

3.5.3 **Fuel Receipt**

The licensee shall implement each operational program identified below prior to initial receipt of fuel on site:

- Fire Protection Program (for elements necessary to support receipt and storage of fuel on site)
- Radiation Protection Program (for elements necessary to support receipt and storage of fuel on site)

3.5.4 **60 days prior to Preoperational Testing**

The licensee shall implement the operational program identified below 60 days prior to the scheduled date of the first preoperational test:

- Initial Test Program – Preoperational Test Program

3.5.5 Fuel Load Authorization

The licensee shall implement the operational program identified below prior to fuel load authorization per 10 CFR 52.103(g):

- Mitigative Strategies Description and Plans (for responding to circumstances associated with loss of large areas of the plant due to explosions or fire developed in accordance with 10 CFR 50.54(hh)(2))

3.5.6 60 days prior to Fuel Loading

The licensee shall implement the operational program identified below 60 days prior to the scheduled date of initial fuel load:

- Initial Test Program – Startup Test Program

3.5.7 Fuel Loading

The licensee shall implement each operational program identified below prior to initial fuel load:

- Environmental Qualification Program
- Reactor Vessel Material Surveillance Program
- Preservice Testing Program
- Fire Protection Program (for elements necessary to support fuel load and plant operation)
- Process and Effluent Monitoring and Sampling Program
- Radiation Protection Program (for elements necessary to support fuel load and plant operation)
- Snubber Testing and Inspection Program – Preservice Testing Program
- Lifecycle Minimization of Contamination

3.5.8 Commercial Service

The licensee shall implement the operational program identified below prior to initial commercial service:

- Flow-Accelerated Corrosion Program

3.5.9 Waste Shipment

The licensee shall implement the operational program identified below prior to initial radioactive waste shipment:

- Radiation Protection Program (for elements necessary to support shipment of radioactive waste)

3.6 Operational Program Readiness

The licensee shall submit to the Director of NRO, a schedule, no later than 12 months after issuance of the COL, for implementation of the operational programs listed in FSAR

Table 13.4-201. The schedule shall be updated every 6 months until 12 months before scheduled fuel loading, and every month thereafter until the operational programs in the FSAR table have been fully implemented. This schedule shall also address:

- The implementation of site-specific Severe Accident Management Guidelines
- The spent fuel rack coupon monitoring program implementation

3.7 Emergency Planning Actions

3.7.1 Emergency Action Levels (EALs)

No later than 180 days prior to initial fuel load, the licensee shall submit to the Director of NRO, or the Director's designee, a fully developed set of site-specific EALs in accordance with NEI 07-01, Revision 0, with no deviations. The EALs shall have been discussed and agreed upon with state and local officials.

3.7.2 On-Shift Staffing

The licensee shall perform a detailed analysis of on-shift staffing, in accordance with NEI 10-05, "Assessment of On-Shift Emergency Response Organization Staffing and Capabilities," Revision 0, and the licensee shall incorporate any changes to the Emergency Plan (EP) needed to bring staff to the required levels, prior to or concurrent with the completion of EP ITAAC 2.0 of Table 2.3-1, and no less than 180 days prior to initial fuel load.

3.8 Actions to Address Fukushima Near-Term Task Force Recommendations

3.8.1 Emergency Planning Actions

At least two years prior to scheduled initial fuel load, the licensee shall have performed an assessment of the onsite and augmented staffing capability to satisfy the regulatory requirements for response to a multi-unit event. The staffing assessment will be performed in accordance with NEI 12-01, "Guideline for Assessing Beyond Design Basis Accident Response Staffing and Communications Capabilities," Revision 0.

At least 180 days prior to scheduled initial fuel load, the licensee shall revise the EP to include the following:

- Incorporation of corrective actions identified in the staffing assessment described above
- Identification of how the augmented staff will be notified given degraded communications capabilities

At least two years prior to scheduled initial fuel load, the licensee shall have performed an assessment of on-site and off-site communications systems and equipment required during an emergency event to ensure communications capabilities can be maintained during prolonged station blackout conditions. The communications capability assessment will be performed in accordance with NEI 12-01, "Guidance for Assessing Beyond Design Basis Accident Response Staffing and Communications Capabilities," Revision 0.

At least 180 days prior to scheduled initial fuel load, the licensee shall complete implementation of corrective actions identified in the communications capability assessment described above, including any related emergency plan and implementing procedure changes and associated training.

3.8.2 Mitigation Strategies for Beyond-Design-Basis External Events

At least 180 days before the date scheduled for initial fuel load as set forth in the notification submitted in accordance with 10 CFR 52.103(a), the licensee shall use the guidance contained in JLD-ISG-2012-01, "Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," Revision 0 and the information presented in FSAR Section 1.5 to complete the development of strategies and guidance to maintain and, if necessary, restore core cooling, containment, and spent fuel pool cooling capabilities beginning 72 hours after loss of all normal and emergency AC power sources, including any alternate AC source under 10 CFR 50.63. These strategies must be capable of:

- Mitigating a simultaneous loss of all AC power sources, both from the on-site and off-site power systems, and loss of normal access to the normal heat sink,
- Maintaining core cooling, containment, and spent fuel pool cooling capabilities for NA3 during and after such an event affecting all units on site, and
- Being implemented in all plant Modes.

Before initial fuel load, the licensee shall fully implement the strategies and guidance required in this license condition, including procedures, training, and acquisition, staging or installing of equipment and consumables relied upon in the strategies.

3.8.3 Reliable Spent Fuel Pool/Buffer Pool Level Instrumentation

The spent fuel pool/buffer pool instrumentation shall be maintained available and reliable through appropriate development and implementation of a training program. The training program shall include provisions to ensure trained personnel can route the temporary power lines from the alternative power source to the appropriate connection points and connect the alternate power source to the safety-related level instrument channels.

3.9 Explosively Actuated Valves

Before initial fuel load, the licensee shall implement a surveillance program for explosively actuated valves (squib valves) in the Gravity-Driven Cooling System and the Automatic Depressurization System at Unit 3 that includes the following provisions in addition to the requirements specified in the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) as incorporated by reference in 10 CFR 50.55a.

a. Preservice Testing (PST)

All explosively actuated valves shall be preservice tested by verifying the operational readiness of the actuation logic and associated electrical circuits for each explosively actuated valve with its pyrotechnic charge removed from the valve. This must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available at the explosively actuated valve from each circuit that is relied upon to actuate the valve. In addition, a sample of at least 20 percent of the pyrotechnic charges in all explosively actuated valves shall be tested in the valve or a qualified test fixture to confirm the capability of each sampled pyrotechnic charge to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping. The sampling must select at least one explosively actuated valve from each redundant safety train. Corrective action shall be taken to resolve any deficiencies identified in the operational readiness of the actuation logic or associated electrical circuits, or the capability of a pyrotechnic charge. If a charge fails to fire or its capability is not confirmed, all charges with the same batch number shall be removed, discarded, and replaced with charges from a different batch number that has demonstrated successful 20 percent sampling of the charges.

b. Operational Surveillance

Explosively actuated valves shall be subject to the following surveillance activities after commencing plant operation:

(1) At least once every 2 years, each explosively actuated valve shall undergo visual external examination and remote internal examination (including evaluation and removal of fluids or contaminants that may interfere with operation of the valve) to verify the operational readiness of the valve and its actuator. This examination shall also verify the appropriate position of the internal actuating mechanism and proper operation of remote position indicators. Corrective action shall be taken to resolve any deficiencies identified during the examination with post-maintenance testing conducted that satisfies the PST requirements.

(2) At least once every 10 years, each explosively actuated valve shall be disassembled for internal examination of the valve and actuator to verify the operational readiness of the valve assembly and the integrity of individual components and to remove any foreign material, fluid, or corrosion. The examination schedule shall provide for each valve design used for explosively actuated valves at the facility to be included among the explosively actuated valves to be disassembled and examined every 2 years. Corrective action shall be taken to resolve any deficiencies identified during the examination with post-maintenance testing conducted that satisfies the PST requirements.

(3) For explosively actuated valves selected for test sampling every 2 years in accordance with the ASME OM Code, the operational readiness of the actuation logic and associated electrical circuits shall be verified for each sampled explosively actuated valve following

removal of its charge. This must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available for each valve actuation circuit. Corrective action shall be taken to resolve any deficiencies identified in the actuation logic or associated electrical circuits.

(4) For explosively actuated valves selected for test sampling every 2 years in accordance with the ASME OM Code, the sampling must select at least one explosively actuated valve from each redundant safety train. Each sampled pyrotechnic charge shall be tested in the valve or a qualified test fixture to confirm the capability of the charge to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping. Corrective action shall be taken to resolve any deficiencies identified in the capability of a pyrotechnic charge in accordance with the PST requirements.

This license condition supplements the current requirements in the ASME OM Code for explosively actuated valves, and sets forth requirements for preservice testing and operational surveillance, as well as any necessary condition. The license condition will expire either when (1) the license condition is incorporated into the Unit 3 Inservice Testing (IST) program; or (2) the updated ASME OM Code requirements for squib valves in new reactors (i.e., plants receiving a construction permit, or a combined license for construction and operation, after January 1, 2000), as accepted by the NRC in 10 CFR 50.55a, are incorporated into the Unit 3 IST program. For the purpose of satisfying the license condition, the licensee retains the option of including in its IST program either the requirements stated in this condition, or including updated ASME OM Code requirements.

3.10 Steam Dryer License Conditions

The licensee shall implement the following license conditions using supporting information in GE Hitachi Nuclear Energy Reports NEDE-33312P, “ESBWR Steam Dryer Acoustic Load Definition,” Revision 5, December 2013, and NEDE-33313P, “ESBWR Steam Dryer Structural Evaluation,” Revision 5, December 2013.

1.a. A Steam Dryer Monitoring Plan (SDMP) for the steam dryer shall be prepared and provided to the NRC no later than 90 days before initial fuel load.

1.b. Power Ascension Test (PAT) procedures for the steam dryer testing shall be provided to NRC inspectors no later than 10 days before initial fuel load. The PAT procedures shall include the following:

- Level 1 and Level 2 acceptance limits for on-dryer strain gages and on-dryer accelerometers to be used up to 100% power
- Specific hold points and their duration during 100% power ascension
- Activities to be accomplished during hold points

- Plant parameters to be monitored
- Actions to be taken if acceptance criteria are not satisfied
- Verification of the completion of commitments and planned actions

2. An initial hold point during the first power ascension shall be at no more than 75 percent of full power. At this hold point, the licensee shall complete the actions specified in item 2 of the model license condition specified in paragraph (c) of Section 10.2, "Comprehensive Vibration Program Elements for a COL Applicant," in NEDE-33313P, Revision 5.

3. Continue power ascension: The licensee shall complete the actions specified in item 3 of the model license condition specified in paragraph (c) of Section 10.2 in NEDE-33313P, Revision 5.

4. Power ascension monitoring: The licensee shall complete the actions specified in item 4 of the model license condition specified in paragraph (c) of Section 10.2 in NEDE-33313P, Revision 5.

5. Flow-induced resonances: The licensee shall complete the actions specified in item 5 of the model license condition specified in paragraph (c) of Section 10.2 in NEDE-33313P, Revision 5.

6. Limit curve modifications: The licensee shall complete the actions specified in item 6 of the model license condition specified in paragraph (c) of Section 10.2 in NEDE-33313P, Revision 5.

7. At the initial hold point and the hold points at approximately 85 and 95 percent power, power ascension shall not proceed for at least 72 hours after making the steam dryer data analysis and results available to the NRC by facsimile or electronic transmission to the NRC project manager.

8. During the Power Maneuvering in the Feedwater Temperature Operating Domain testing, pressures, strains, and accelerations shall be recorded from the on-dryer mounted instrumentation across the expected range of normal steady state plant operating conditions. An evaluation of the dryer structural response over the range of steady state plant operating conditions shall be included in the stress analysis report described in license condition 3.10.9 (below).

9. Full power achievement: The licensee shall complete the actions specified in item 9 of the model license condition specified in paragraph (c) of Section 10.2 in NEDE-33313P, Revision 5.

10. A periodic steam dryer inspection program will be implemented as follows:

a. During the first two scheduled refueling outages after reaching full power conditions, a visual inspection shall be conducted of all accessible areas and susceptible locations of the steam dryer in accordance with accepted industry guidance on steam dryer inspections. The results of these baseline inspections shall be provided to the NRC within 60 days following startup after each outage.

b. At the end of the second refueling outage following full power operation, an updated SDMP reflecting a long-term inspection plan based on plant-specific and industry operating experience shall be provided to the NRC within 180 days following startup from the second refueling outage.

3.11 Financial Protection License Conditions

3.11.1 Before the scheduled date of initial fuel load, and within ninety (90) days after the NRC publishes the notice of intended operation in the *Federal Register*, Dominion Virginia Power shall provide evidence to the NRC that it would have the ability to pay into the nuclear industry retrospective rating plan in the event of a nuclear incident and in the amount specified in 10 CFR 140.11(a)(4) for one calendar year using one of the following methods:

(a) Surety bond,

(b) Letter of credit,

(c) Revolving credit/term loan arrangement,

(d) Maintenance of escrow deposits of government securities, or

(e) Annual certified financial statement showing either that a cash flow (i.e., cash available to a company after all operating expenses, taxes, interest charges, and dividends have been paid) can be generated and would be available for payment of retrospective premiums within three (3) months after submission of the statement, or a cash reserve or a combination of cash flow and cash reserve.

Thereafter, Dominion Virginia Power shall annually provide evidence of such guarantee in accordance with the provisions in 10 CFR 140.21.

3.11.2 Before the scheduled date for initial fuel load, Dominion Virginia Power shall provide satisfactory documentary evidence to the Director of the Office of Nuclear Reactor Regulation, or designee, that it has obtained the appropriate amount of secondary financial protection pursuant to 10 CFR 140.11(a)(4), and the appropriate amount of financial protection pursuant to 10 CFR 50.54(w).