PTN COL 7.5-1

Table 7.5-202
Summary of Type E Variables[(a)]

Function Monitored	Variable	Type/ Category
Environs Radiation and Radioactivity	Plant Environs radiation levels and airborne radioactivity	E3
Meteorology	Wind speed, wind direction, and estimation of atmospheric stability (based on vertical temperature difference)	E3

(a) This Table supplements DCD Table 7.5-8 and provides the site specific information noted in the variable column of DCD Table 7.5-8.

7.6 INTERLOCK SYSTEMS IMPORTANT TO SAFETY

This section of the referenced DCD is incorporated by reference with no departures or supplements.

7.7 CONTROL AND INSTRUMENTATION SYSTEMS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

CHAPTER 8: ELECTRIC POWER
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CHAPTER 8 ELECTRIC POWER

8.1 INTRODUCTION

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

8.1.1 UTILITY GRID DESCRIPTION

PTN SUP 8.1-1 Replace the existing information in DCD Subsection 8.1.1 with the following:

FPL owns and operates the power transmission system for Turkey Point Units 6 & 7. FPL is the largest investor-owned electric utility in Florida, serving more than 4.4 million customers. The FPL power transmission system consists of transmission lines and substations that link the various generation facilities, load centers, and grid interties within the FPL service territory at various voltages ranging from 69 kV to 500 kV. FPL maintains multiple direct interconnections with neighboring utilities. FPL also participates as a member of the Florida Reliability Coordinating Council and the North American Electric Reliability Corporation.

The plant switchyard (Clear Sky substation) on the Turkey Point plant area is used to transmit the electric power output from Units 6 & 7 to the FPL transmission system. The switchyard also serves as the units' preferred and maintenance source. The switchyard has two sections. The nominal operating voltage of these sections is 230 kV and 500 kV. These sections are interconnected with 230 kV/ 500 kV autotransformers. The 230 kV section of the plant switchyard is configured in a breaker-and-a-half bus arrangement, whereas the configuration of the 500 kV section of the switchyard is a double-breaker and a double-bus arrangement. The transmission system is connected to the Clear Sky substation through two 500 kV and two 230 kV transmission lines. Additionally, there is a 230 kV tie-line between the Clear Sky substation and the Turkey Point substation.

8.1.4.3 Design Criteria, Regulatory Guides, and IEEE Standards

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PTN SUP 8.1-2 Add the following information between the second and third paragraph of this subsection.

Offsite and onsite ac power systems' conformance to RGs and IEEE standards identified by DCD Table 8.1-1 as site-specific and to other applicable RGs is as indicated in Table 8.1-201.

PTN SUP 8.1-2

Table 8.1-201
Site-Specific Guidelines for Electric Power Systems

Criteria				Applicability (FSAR[a] Section/Subsection)			Remarks
				8.2	8.3.1	8.3.2	
1.	Regulatory Guides						
	a.	RG 1.129	Maintenance, Testing, and Replacement of Vented Lead Acid Storage Batteries for Nuclear Power Plants			G	Battery service tests are performed in accordance with the RG.
	b.	RG 1.155	Station Blackout				Not applicable[b]
	c.	RG 1.204	Guidelines for Lightning Protection of Nuclear Power Plants	G	G		
	d.	RG 1.206	Combined License Applications for Nuclear Power Plants (light water reactor edition)	G	G	G	
2.	Branch Technical Positions						
	a.	BTP 8-3 (BTP ICSB-11 in DCD)	Stability of Offsite Power Systems	G			Stability Analysis of the Offsite Power System is performed in accordance with the BTP.

(a) "G" denotes guidelines as defined in NUREG-0800, Table 8-1 (SRP). No Letter denotes "Not applicable."
(b) Station Blackout and the associated guidelines were addressed as a design issue in the DCD.

8.2 OFFSITE POWER SYSTEM

This section of the referenced DCD is incorporated by reference with the following departure(s) and/or supplement(s).

8.2.1 SYSTEM DESCRIPTION

Delete the first, second, and sixth paragraphs and the first and last sentences of the fourth paragraph, of DCD Subsection 8.2.1. Add the following information before the fifth paragraph of DCD Subsection 8.2.1.

PTN COL 8.2-1 The offsite power system for Turkey Point Units 6 & 7 has four transmission lines from the FPL transmission network to the plant switchyard (Clear Sky substation) from three physically independent substations. The plant switchyard also includes a normally open supply circuit from the existing Turkey Point substation serving Turkey Point Units 1 through 5. This circuit provides an emergency source for offsite power from Turkey Point substation in the event of loss of power in all four transmission circuits to the plant switchyard.

The plant switchyard has two operating voltages with autotransformers interconnecting the 500 kV and 230 kV sections. The Units 6 & 7 main step-up transformers (GSU) and reserve auxiliary transformers (RAT) are connected at 230 kV to the plant switchyard. The interconnection of Units 6 & 7, the switchyard, and the 230 kV and 500 kV transmission systems is shown on Figure 8.2-201 and Figure 8.2-202.

There are two independent 500 kV transmission lines connected to the plant switchyard, and two independent 230 kV transmission lines. As shown below, each transmission line is tied into an FPL substation located between 19 and 52 miles from the plant. There is a 230 kV tie-line between the plant switchyard and the Turkey Point substation which is within the Turkey Point plant property.

Nominal Voltage (kV)	Termination Point	Length (miles)	Thermal Rating (MVA)
500	Levee 500 kV	43	3464
500	Levee 500 kV	43	3464
230	Davis 230 kV	19	1191
230	Pennsuco 230 kV	52	1191
230	Turkey Point (normally open)	0.5	1191

The transmission lines are divided into two separate transmission corridors. They enter the common switchyard from different directions and are maintained in separate rights-of-way. The two 500 kV lines and the Pennsuco 230 kV line are in the west transmission corridor and the Davis 230 kV line and the 230 kV line to Turkey Point substation are in the east transmission corridor.

The transmission lines are designed to meet all requirements of the National Electric Safety Code (Reference 201). Transmission line structures and support structures and systems are designed to the loading requirements of the NESC and FPL standards. The transmission lines are designed with a basic insulation level (BIL) that will minimize flashovers caused by lightning.

Galloping conductors are not anticipated.

PTN CDI

A transformer area containing the main step-up transformer, the unit auxiliary transformers, and reserve auxiliary transformers is located next to each turbine building.

8.2.1.1 Transmission Switchyard

Replace the information in DCD Subsection 8.2.1.1 with the following information.

PTN COL 8.2-1

The 500 kV section of the plant switchyard is configured in a double-breaker and double-bus arrangement to make two circuits for connecting two transmission lines. Each 500 kV bus is connected to one 230 kV bus by separate 1500 megavolt ampere (MVA) autotransformers. High-side and low-side bank breakers are provided for the autotransformers. All breakers are in the closed position and

energized under normal operation. The 500 kV buses, circuit breakers and disconnect switches are rated for a continuous current of 4000 A and a fault duty rating of 50 kA.

The 230 kV buses, circuit breakers and disconnect switches are rated for a continuous current of 4000 A and a fault duty rating of 63 kA.

The plant switchyard includes one terminal for the Unit 6 main step-up transformer connection, one terminal for the Unit 7 main step-up transformer connection, two terminals for connections to the Unit 6 reserve auxiliary transformers, and two terminals for connections to the Unit 7 reserve auxiliary transformers.

Underground conductors are used to connect the main step-up and reserve auxiliary transformers to the switchyard. The conductors for each transformer are routed separately and are protected by reinforced concrete enclosures.

The configuration of the switchyard is shown in Figure 8.2-202.

The switchyard includes surge protective devices, grounding and a lightning protection system in accordance with standard industry practice.

Failure Modes and Effects Analysis

PTN SUP 8.2-1

The design of the offsite power system provides for a robust system that supports reliable power production. While offsite power is not required to meet any safety function, multiple, reliable transmission circuits are provided to support operation of the Units 6 & 7 facilities. Neither the accident analysis nor the probabilistic risk assessment has identified the nonsafety-related offsite power system as risk significant for normal plant operation.

The offsite power system for Units 6 & 7 has four transmission lines from the FPL transmission network to the plant substation from three physically independent substations. No single transmission line is designated as the preferred circuit for Unit 6 or for Unit 7. Each of the transmission lines has sufficient capacity and capability from the transmission network to power the plant loads for both units under normal, abnormal and accident conditions. Each 230 kV bus is split into two sections by a bus breaker to prevent loss of both units with one bus out of service (on clearance) and a trip of the other 230 kV bus.

A failure modes and effects analysis of the Clear Sky substation confirms that a single initiating event, such as transmission line fault plus a single breaker not operating, does not cause failure of more than one single offsite transmission line, or a loss of offsite power to either Units 6 or 7 onsite buses via the main step-up transformer. This evaluation recognizes that a single failure of some switchyard components could directly cause the loss of the switchyard feed to a unit's main step-up transformer such as a fault on this feed. Evaluated events include a breaker not operating during a fault condition, a fault on a switchyard bus, a spurious relay trip, or a loss of control power supply. In summary:

- In the event of a fault on a 500 kV transmission line (or spurious relay operation), the two associated line circuit breakers trip to isolate the line. All other equipment remains energized.

- In the event of a fault on a 500 kV transmission line with a stuck line breaker, the breaker failure relay causes all circuit breakers on the affected bus to trip, and thereby, de-energizes the affected bus and disconnect one autotransformer. All other equipment remains energized.

- In the event of a 500 kV bus fault, (or spurious relay operation), the breakers associated with the affected bus trip, thereby isolating the faulted bus and disconnecting one autotransformer. All other equipment remains energized.

- In the event of a 500 kV bus fault with a stuck line breaker, the breaker failure relay trips the adjacent line breaker and initiates transfer trip to the remote substation to isolate the faulted bus and one 500 kV transmission line. All other equipment remains energized.

- In the event of a 500 kV bus fault with a stuck high-side autotransformer breaker, the breaker failure relay trips the low-side autotransformer breaker to isolate the faulted bus and the autotransformer. All other equipment remains energized.

- In the event of a fault on a 230 kV transmission line (or spurious relay operation), the two associated circuit breakers trip to isolate the line and all other equipment remains energized.

- In the event of a fault on a 230 kV transmission line with a stuck center position breaker, the breaker failure relay trips the adjacent breaker and thereby isolating the faulted transmission line and de-energizing one reserve auxiliary transformer. All other equipment remains energized.

- In the event of a fault on a 230 kV transmission line with a stuck bus breaker, the breaker failure relay causes all circuit breakers on the affected bus to trip and thereby de-energize the affected bus. All other equipment remains energized.

- In the event of a 230 kV bus fault (or spurious relay operation), the breakers associated with the affected bus trip, thereby isolating the faulted bus. All other equipment remains energized.

- In the event of a 230 kV bus fault with a stuck breaker, the breaker failure relay trips the adjacent breaker to isolate the faulted bus. If the stuck breaker is associated with either the Unit 6 or 7 main step-up connections, opening of the adjacent breaker interrupts power to the associated main step-up and unit auxiliary transformer resulting in the loss of both preferred and normal sources of power to the unit. The switchyard feeds to the reserve auxiliary transformers are still available.

- In the event of a fault on one of the 500/230 kV autotransformers (or spurious relay operation), the autotransformer bus breakers trip in the 500 kV and 230 kV switchyards to isolate the autotransformer. All other equipment remains energized.

- In the event of a fault on one of the 500/230 kV autotransformers with a stuck bus circuit breaker, the breaker failure relay trips all the breakers on the affected bus and thereby isolates the affected bus. All other equipment remains energized.

- Failure of protective relays or breaker trip coils or dc control power is compensated for by redundant relays and breaker trip coils powered from different dc sources, which allows the protective function to occur. (Failure of protective relays or breaker trip coils or dc control power is automatically detected and an alarm is given.)

The results of the above failure modes and effects analysis show that a single fault in any section of the 230 kV or 500 kV bus is cleared by the adjacent breakers and does not interrupt operation of the remaining part of the switchyard bus or the connection of the unaffected transmission lines. A bus fault with a stuck breaker associated with a main step-up transformer connection causes the loss of preferred power to the associated Turkey Point unit. The switchyard feeds to the reserve auxiliary transformers are still available. A bus fault concurrent with any other stuck breaker does not cause a loss of power to either Unit 6 or 7.

Transmission System Provider/Operator

PTN SUP 8.2-2

FPL is the transmission system provider/operator and it constructs, owns, and operates all substation and transmission facilities between the plant and the points of interconnection to the grid. An interface agreement in accordance with the North American Electric Reliability Corporation (NERC) Standard NUC-001-01, between FPL Transmission & Substation-Power Supply Department and Units 6 & 7 will establish the protocol to provide effective monitoring and oversight of all grid, switchyard, and plant activities. These activities include maintenance, testing, planned outages, load reductions, and emergent conditions that could affect offsite power reliability. Department directives will implement the agreement and will facilitate prompt and effective communications between the FPL power supply system operator and Units 6 & 7 shift manager or unit supervisor. Procedures will be established to ensure switchyard maintenance and design changes are reviewed before implementation.

FPL uses a real-time contingency analysis computer program that is used by FPL's transmission system operators in determining the security level of the transmission system by performing an analysis using a predefined set of contingency criteria (e.g., single contingency). The computer program simulates a list of active contingencies on the current power system and produces an output of system conditions for each defined contingency. The program provides an updated output approximately every 5 minutes using real-time system conditions (e.g., real-time line outages, real-time flows and voltages, real-time breaker status, etc.). For each defined contingency simulated, specified elements are checked for limit violations (e.g. line overloads, voltage limits, and reactive limits at generator buses). All contingencies that cause violations are output along with the identification of the violations and information on the magnitude of the violation. The current and previous outputs are displayed to determine degree of change as compared to the previous contingency analysis output result.

A priority is also designated for each contingency. Violations of nuclear plant limits are assigned the highest priority and if a violation is detected by the contingency analysis computer program, it is reported at the top of the output violation list. The computer program alerts the system operator of abnormal voltages, overloads, or unit limitations that can be created by a loss of one or several elements of the transmission system. The output of the contingency analysis computer program is

used continuously by the operators to make critical decisions in response to potential severe conditions.

Minimum and maximum voltage criteria specific to the Units 6 & 7 switchyard buses will be documented in the interface agreement. The Units 6 & 7 agreement will also specify that the Units 6 & 7 shift manager or unit supervisor be notified within 15 minutes if a condition exists or is forecasted to exist (i.e., via contingency analysis computer program) that would result in minimum or maximum switchyard voltage requirements for Units 6 & 7 switchyard being exceeded. This agreement, as well as the overall switchyard agreement, will require restoration of power to Units 6 & 7 on a first-priority basis in the event of a loss of offsite power. The goal for maximum restoration time will be 30 minutes.

8.2.1.2 Transformer Area

Add the following paragraph and subsections at the end of the DCD Subsection 8.2.1.2.

PTN COL 8.2-1 The transformer area for each unit contains the main step-up transformers (three single-phase transformers plus one spare), three unit auxiliary transformers, and two reserve auxiliary transformers. The reserve auxiliary transformers are connected to the 230 kV section of the switchyard. The 230 kV windings of the main step-up transformer are connected in a wye configuration and connected to the 230 kV section of the switchyard.

8.2.1.2.1 Switchyard Protection Relay Scheme

PTN COL 8.2-2 The switchyard's relay protection schemes continuously monitor the conditions of the power system and are designed to detect and isolate the faults with maximum speed and minimum disturbance to the system. The schemes consist of primary and secondary relaying systems that use separate instrument current transformers for monitoring, separate trip circuits, and separate dc power supplies to achieve redundancy in their protection functions. The principal features of the schemes provided for different equipment are described below:

- Each of the 500 kV and 230 kV transmission lines is protected by two independent pilot systems that provide high-speed clearing for a fault anywhere on the line.

- The switchyard 500/230 kV autotransformers and switchyard buses have primary and secondary protective relaying systems that provide high-speed clearing for a fault within the switchyard.

- The 230 kV circuits to the main step-up and reserve auxiliary transformers have primary and secondary protective relaying systems located in the switchyard control building that communicate via fiber optics to the associated protective relaying system located in the plant.

Breaker failure relays are provided for all switchyard breakers to isolate a failed breaker from all switchyard sources. In addition, for the switchyard breakers connected to the main step-up and reserve auxiliary transformers, the remote sources are isolated using direct transfer trip communication.

The protective devices controlling the switchyard breakers are set with consideration given to preserving the plant grid connection following a turbine trip.

PTN SUP 8.2-4

8.2.1.2.2 Plant Response to High Voltage Open Phase Condition

A monitoring system is installed on the credited GDC 17 offsite power circuit that provides continuous open phase condition monitoring of the main step-up (MSU) transformer high voltage (HV) input power supply (Reference 202). The system detects an open phase condition (with or without a concurrent high impedance ground on the HV side of the transformer) on one or more phases under all transformer loading conditions. The open phase condition monitoring system provides an alarm to the operators in the control room should an open phase condition occur on the HV source to the MSU transformers. The system design utilizes commercially available components including state of the art digital relaying equipment and input parameters as required to provide loss of phase detection and alarm capability.

Additionally, a high-voltage open phase condition with or without a ground fault can manifest itself as an unacceptable voltage on the 6.9 kV medium voltage ES-1 and ES-2 buses during normal loading conditions. The presence of unacceptable voltages on the ES-1 and ES-2 buses results in isolation of the affected medium voltage bus from the offsite power supply and enables the onsite

standby diesel generators to start and restore AC power to the ES-1 and ES-2 buses and associated defense-in-depth loads. The onsite AC power system is described in DCD Section 8.3.1.

Motor management relays for the medium voltage motors on ES-1 and ES-2 provide detection of unacceptably high negative sequence currents. High negative sequence current motor trips or other running load trips provide alarms in the main control room (MCR), which can assist in the detection of a high-voltage open phase condition with or without a ground fault. Electric circuit protection for the medium voltage system and equipment is described in DCD Section 8.3.1.1.1.1.

A high-voltage open phase condition with or without a ground fault can also manifest itself as an unacceptable voltage on the 480 VAC low-voltage buses powered from ES-1 and ES-2. The safety related IDS battery chargers are powered from the low-voltage buses and continue to charge the IDS batteries unless the battery charger input or output monitored electrical parameters are unacceptable. If the monitored electrical parameters degrade to the point that the battery charger no longer provides sufficient DC bus voltage, the Class 1E electrical system DC bus receives power from the applicable IDS battery and the battery charger maintains isolation between the Non-Class 1E AC and Class 1E DC power systems which generates alarms in the MCR. The onsite AC power system is described in DCD Section 8.3.1 and the Class 1E DC power system is described in DCD Section 8.3.2.1.1.

Operator actions and maintenance and testing activities are addressed in procedures, as described in Section 13.5. Plant operating procedures, including off-normal operating procedures associated with the monitoring system, will be developed prior to fuel load. Maintenance and testing procedures, including calibration, surveillance testing, setpoint determination and troubleshooting procedures associated with the monitoring system, will be developed prior to fuel load.

Control Room operator and maintenance technician training associated with the operation and maintenance of the monitoring system will be conducted in accordance with the milestones for Non-Licensed Plant Staff and Reactor Operator Training Programs in Table 13.4-201.

8.2.1.3 Switchyard Control Building

PTN COL 8.2-1

A control building within the switchyard houses redundant dc battery systems and accommodates a sufficient number of relay and control panels to serve the requirements of the switchyard.

The controls for switchyard breakers associated with the Units 6 & 7 main step-up transformers are under the administrative control of the plant. The controls for these breakers are located inside the plant.

The system control center of FPL transmission and substation operations has operational control over the other breakers in the switchyard (including those associated with the reserve auxiliary transformers).

The switchyard's normal ac power is supplied from station service transformers supplied by the tertiary windings of the 500/230 kV autotransformers. A backup source of ac power to the switchyard is supplied from a plant source.

8.2.1.4 Switchyard and Transmission Line Testing and Inspection

FPL uses a process called The Phoenix Assurance Process to ensure the installations of new, relocated, or modified facilities are fully operational before being placed into service. The purpose of this process is to provide the procedures used for equipment installation and collection of installation/ commissioning data. This assurance documentation is compiled into an assurance book for each facility and serves as a source of baseline data for installations. The objective of Phoenix is fourfold: safety (zero injuries), facilities operate correctly after they are put into service, no rework associated with the installation of facilities, and documentation for new assets are recorded, and lessons learned are passed on for future reference.

It is the responsibility of personnel involved in the engineering, procurement, construction, installation, and commissioning of new equipment to supply proper documentation based on the requirements of the Phoenix Assurance Process.

The Phoenix Assurance Process covers acceptance, commissioning, and in-service testing for new equipment and defines the responsibility of each responsible person associated with the project. An individual, station-specific

book is assembled, incorporating, for each component, the specific procedures, FPL quality assurance checklists, and forms prepared for the purpose of ensuring equipment is ready for service.

The transmission switchyard interface agreement will specify that grid maintenance and testing activities that could affect offsite power reliability be closely coordinated with Units 6 & 7. This agreement will clearly state that the plant switchyard equipment is maintained by FPL transmission and substation operations.

FPL transmission and substation operations will conduct regular inspections of the plant switchyard and perform regular maintenance and necessary repair or replacement of equipment.

For performance of maintenance, testing, calibration, and inspection, FPL follows its own field test manuals, vendor manuals and drawings, and industry's maintenance practices to comply with applicable NERC reliability standards.

FPL verifies that these test results demonstrate compliance and takes corrective actions as necessary. FPL plans and schedules maintenance activities and notifies the nuclear plant in advance.

The interconnecting switchyard, as well as other substation facilities, has multiple levels of inspection and maintenance. They include the following:

- Monthly walk-through and visual inspection.
- Quarterly oil sampling of power transformers at generating stations. Oil samples are tested for dissolved gas analysis and oil quality.
- Power circuit breakers are inspected and maintained according to the number of operations and length of time in service, in accordance with the breaker manufacturer's recommendations.
- Doble power testing on power transformers.
- Infrared testing on bus and equipment to identify hot spots.
- Relay functional tests.

8.2.2 GRID STABILITY

Add the following information at the end of DCD Subsection 8.2.2.

PTN COL 8.2-2 The Florida Reliability Coordinating Council (FRCC) is the approving grid organization for reliability studies performed on the area bulk electric system. FPL, as the transmission service provider and member of the FRCC, conducts ongoing planning studies of the transmission grid. Model data used to perform simulation studies of projected future conditions is maintained and updated as load forecasts and future generation/transmission changes evolve. Studies are performed annually to assess future system performance in accordance with NERC reliability standards. These studies form a basis for identifying future transmission expansion needs. New, large generating units requesting to connect to the area bulk electric system are required to complete the large generator interconnection procedure. The studies performed by FPL as part of this procedure examine the generating unit (combined turbine generator-exciter), the main step-up transformer(s), the switchyard to which the generators are connected, and the transmission system.

FPL performed the required studies to provide an analysis of the stability of the grid with the Units 6 & 7 nuclear units interconnected and integrated into the FPL transmission system. The analysis included an assessment of how the generators and system would perform following potential severe disturbances.

Models used for the analysis were based on the latest available load forecasts, generation expansion plan and system plans for 10 years into the future. As the load forecasts and system plans are updated (e.g., topological changes, generation retirements or additions), the performance of the system is reviewed as part of the normal transmission system assessment to ensure compliance with NERC and FRCC reliability standards and the effectiveness of the transmission plan.

The performance of the grid stability analysis study consisted of dynamic simulation and power flow analysis of the post-transient condition for each case examined. The simulation results were analyzed for any sign of instability, protective relay action, load shedding, voltage, or line-loading violations.

A dynamic stability analysis was conducted to assess the response of the transmission system to various system disturbances. The grid stability study examined the following contingencies:

- Loss of the largest source
- Loss of the most critical transmission circuit
- Loss of the largest load
- Grid stability following turbine trip (minimum of 3 seconds)
- Breaker failure

Dynamic simulations were performed using the latest available FY 2007 FRCC 2017 summer peak base case scaled to 2020 peak load and average (60 percent of peak) load levels combined with the NERC Multiregional Modeling Working Group, FY 2006, 2012 stability case for the southern region with existing commitments of all of the companies in Florida. The study cases assumed the connection of the Units 6 & 7 and attendant incremental facilities in the base case. Units 6 & 7 were modeled as two generating units, each with a rating of 1389 MVA connected at 230 kV to the Clear Sky substation.

Study cases were selected to identify system performance under stressed but likely scenarios. An off-peak load level is the more stressed scenario for stability. Conditions more likely to occur at summer peak load and average load (approximately 60 percent of summer peak) were considered.

The simulation results were analyzed for any sign of instability, protective relay action, or load shedding. The simulation results showed that the Units 6 & 7 plant and transmission system responses to the contingency events were acceptable.

Power flow analysis of the post transient condition for each case was performed. This analysis was used to assess whether the event causes any voltage or line-loading violations.

The study was conducted by performing steady-state and transient stability analyses. Cases studied included loss of the largest source, loss of the most critical transmission circuit, loss of the largest load, grid stability following turbine trip (minimum of 3 seconds), and breaker failure. The performance of the system complies with NERC reliability standards for normal TPL-001-0 Category A, single contingency TPL-002-0 Category B, multiple contingency TPL-003-0 Category C, and extreme bulk electric system events TPL-004-0 Category D. The simulation results were analyzed for any sign of instability, protective relay action, load shedding, voltage or line-loading violations.

The results of the grid stability analysis study do not indicate a loss of electric power from any remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power units or the loss of power from the transmission network.

In order to maintain reactor coolant pump operation for three seconds following a turbine trip as specified in DCD Subsection 8.2.2, the grid voltage at the high-side of the GSU and RATs cannot dip more than 0.15 p.u. from the pre-trip steady-state voltage. The results of turbine trip simulations demonstrate that the voltage and frequency of the 230 kV switchyard buses remain within the limits required to maintain reactor coolant pump operation for at least 3 seconds following a turbine trip in either Unit 6 or 7.

Table 8.2-201 confirms that the interface requirements for steady-state load, inrush kVA for motors, nominal voltage, allowable voltage regulation, nominal frequency, allowable frequency fluctuation, maximum frequency decay rate, and the limiting under frequency value for the reactor coolant pump have been met.

PTN SUP 8.2-3

For the period from January 1, 1988, through September 30, 2008, the average grid availability for the eight 230 kV lines from the existing Turkey Point substation and two 500 kV lines from Levee substation in the FPL system is approximately 99.8 percent with only 48 forced outages lasting more than one hour. The average frequency of forced line outages is approximately 1.4 line outages per year for these transmission lines. The majority of the outages where the cause was recorded were due to environmental conditions and equipment malfunction. Other causes for outages were foreign intervention, human error, and relay misoperation.

8.2.5 COMBINED LICENSE INFORMATION FOR OFFSITE ELECTRICAL POWER

PTN COL 8.2-1

This COL Item 8.2-1 is addressed in Subsections 8.2.1, 8.2.1.1, 8.2.1.2, 8.2.1.3, and 8.2.1.4.

PTN COL 8.2-2 This COL Item 8.2-2 is addressed in Subsections 8.2.1.2.1 and 8.2.2.

8.2.6 REFERENCES

201. Institute of Electrical and Electronics Engineers, *National Electric Safety Code, C2-2007*.

202. NRC Bulletin 2012-01, *Design Vulnerability in Electric Power System*, July 27, 2012.

Table 8.2-201
Grid Stability Interface Evaluation

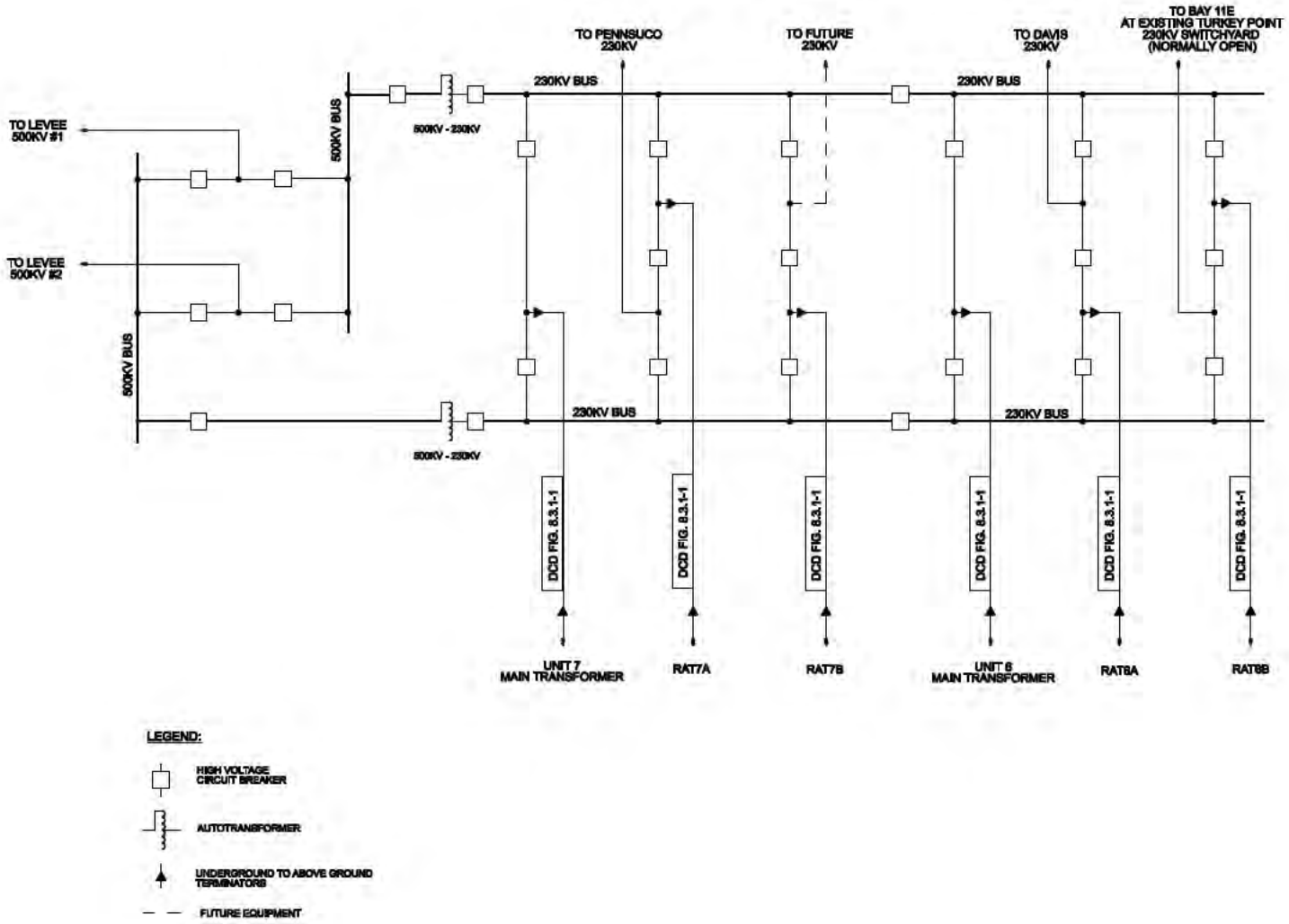
DCD Table 1.8-1 Item 8.2 Parameter	WEC Offsite AC Requirement	Turkey Point Units 6 & 7 Value Assumed
Steady-state load	"normal running values provided as input to grid stability"	Load in each Unit = (100 +j 60) MVA
Inrush kVA for motors	56,712 kVA*	56,712 kVA*
Nominal voltage	Not provided	230 kV
Allowable voltage regulation	0.95-1.05 p.u. steady state 0.15 p.u. transient dip**	0.95-1.05 p.u. steady state 0.15 p.u. transient dip**
Nominal frequency	60 Hz	60 Hz
Allowable frequency fluctuation	± 1/2 Hz indefinite	± 1/2 Hz indefinite
Maximum frequency decay rate	5 Hz/sec	5 Hz/sec

*Based on the inrush of a single 10,000 HP feedwater pump assuming efficiency = 0.95, pf = 0.9, and inrush = 6.5 x FLA
**Applicable to Turbine Trip Only. The maximum allowable voltage dip from the pre-event steady state voltage value during the 3-second turbine trip transient event as measured at the point of connection to the high side of the generator step-up transformer and the reserve auxiliary transformer.

DCD Table 1.8-1 Item 8.2 Parameter	WEC Offsite AC Requirement	Turkey Point Units 6 & 7 Value Calculated
Limiting under frequency value for RCP	≥ 57.7 Hz	≥ 59.73 Hz

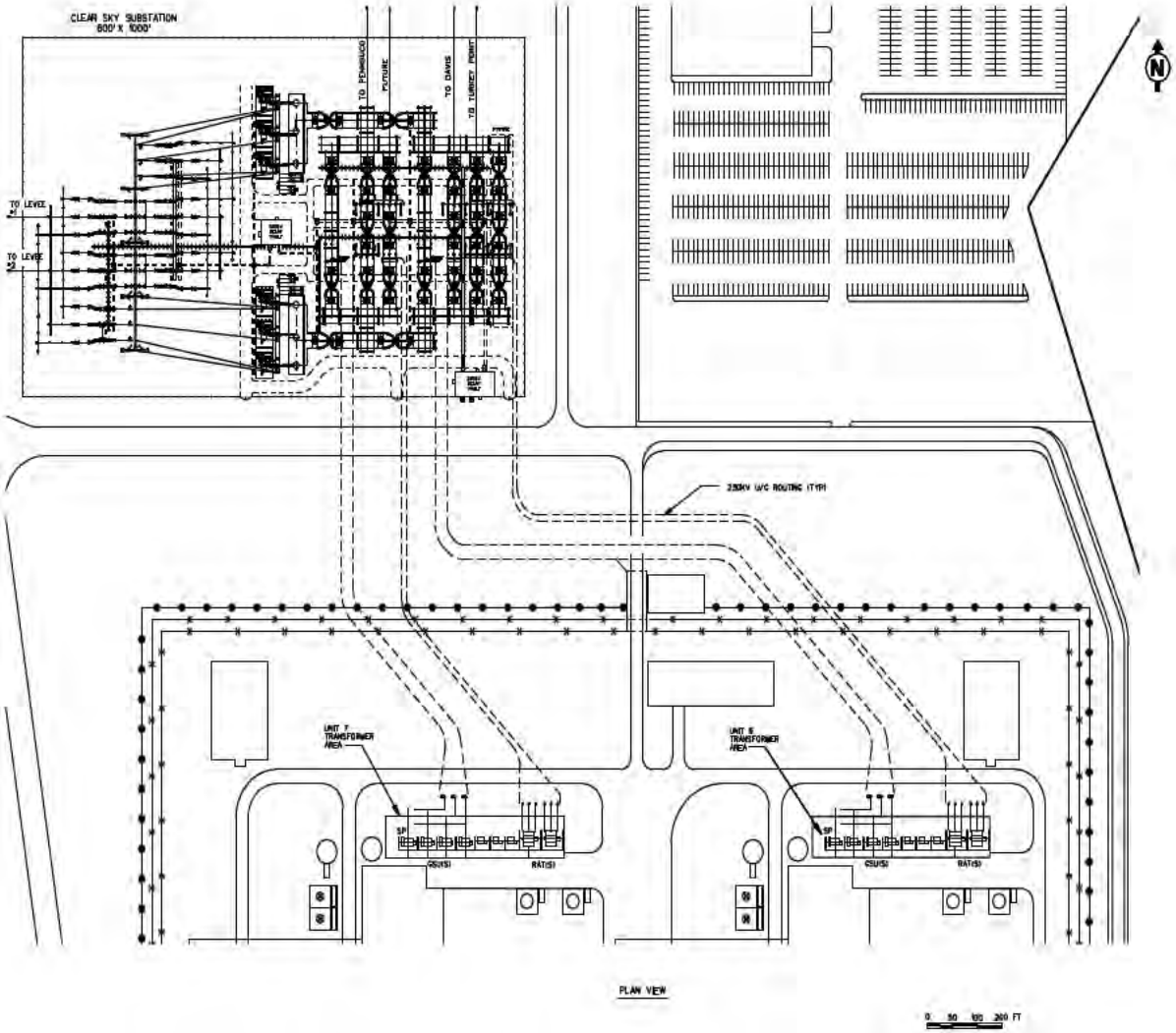
PTN COL 8.2-1

Figure 8.2-201 Offsite Power System One-Line Diagram



PTN COL 8.2-1

Figure 8.2-202 Switchyard General Arrangement



8.3 ONSITE POWER SYSTEMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

8.3.1.1.1 Onsite AC Power System

PTN SUP 8.3-1 Add the following to the end of fourth paragraph of DCD Subsection 8.3.1.1.1.

The site-specific switchyard and transformer voltages are shown on Figure 8.2-201.

8.3.1.1.2.3 Onsite Standby Power System Performance

PTN SUP 8.3-2 Add the following text between the second and third paragraphs of DCD Subsection 8.3.1.1.2.3.

The Turkey Point Units 6 & 7 site conditions provided in Sections 2.1 and 2.3 are bounded by the standard site conditions used to rate both the diesel engine and the associated generator in DCD Subsection 8.3.1.1.2.3.

Add the following subsection after DCD Subsection 8.3.1.1.2.3.

8.3.1.1.2.4 Operations, Inspection and Maintenance

STD COL 8.3-2 Operation, inspection and maintenance (including preventive, corrective, and predictive maintenance) procedures consider both the diesel generator manufacturer's recommendations and industry diesel working group recommendations.

8.3.1.1.6 Containment Building Electrical Penetrations

Add the following text at the end of DCD Subsection 8.3.1.1.6.

STD COL 8.3-2 Procedures implement periodic testing of protective devices that provide penetration overcurrent protection. A sample of each different type of overcurrent device is selected for periodic testing during refueling outages. Testing includes:

- Verification of thermal and instantaneous trip characteristics of molded case circuit breakers.
- Verification of long time, short time, and instantaneous trips of medium voltage vacuum circuit breakers.
- Verification of long time, short time, and instantaneous trips of low voltage air circuit breakers.
- Verification of Class 1E and non-Class 1E dc protective device characteristics (except fuses) per manufacturer recommendations, including testing for overcurrent interruption and/or fault current limiting.

Penetration protective devices are maintained and controlled under the plant configuration control program. A fuse control program, including a master fuse list, is established based on industry operating experience.

8.3.1.1.7 Grounding System

Replace the sixth paragraph of DCD Subsection 8.3.1.1.7 with the following information.

PTN COL 8.3-1 A grounding grid system design within the plant boundary includes determination of step and touch potentials and ensuring that they are within the acceptable limit for personal safety. The soil resistivity test data for the soil samples from the existing Turkey Point Unit has been analyzed and used in the grounding grid system design. The engineered fill for the Units 6 & 7 will be similar to the existing unit's fill. The ground grid conductor size was determined using methodology outlined in IEEE 80, *IEEE Guide for Safety in AC Substation Grounding* (Reference 201) and a grid configuration for the site was created. The grid configuration was modeled in conjunction with the soil model. The resulting step and touch potentials are within the acceptable limits.

8.3.1.1.8 Lightning Protection

Replace the third paragraph of DCD Subsection 8.3.1.1.8 with the following information.

PTN COL 8.3-1 In accordance with IEEE 665-1995, *IEEE Guide for Generating Station Grounding* (DCD Section 8.3, Reference 18), a lightning protection risk assessment for the structures comprising the Units 6 & 7 was performed based on the methodology in NFPA 780-2008, *Standard for Installation of Lightning Protection Systems*, 2008 Edition (Reference 202). Lightning protection is provided for the Units 6 & 7 structures in accordance with NFPA 780. The zone of protection is based on the elevations and geometry of the structures. It includes the space covered by a rolling sphere having a radius sufficient to cover the structure to be protected. The zone of protection method is based on the use of ground masts, air terminals, and shield wires. Either copper or aluminum is used for lightning protection. Lightning protection grounding is interconnected with the station/switchyard grounding system.

8.3.1.4 Inspection and Testing

Add the following text at the end of DCD Subsection 8.3.1.4

STD SUP 8.3-4 Procedures are established for periodic verification of proper operation of the Onsite AC Power System capability for automatic and manual transfer from the preferred power supply to the maintenance power supply and return from the maintenance power supply to the preferred power supply.

8.3.2.1.1.1 Class 1E DC Distribution

Add the following text at the end of DCD Subsection 8.3.2.1.1.1.

STD SUP 8.3-3 No site-specific non-Class 1E dc loads are connected to the Class 1E dc system.

8.3.2.1.4 Maintenance and Testing

Add the following text at the end of DCD Subsection 8.3.2.1.4.

STD COL 8.3-2 Procedures are established for inspection and maintenance of Class 1E and non-Class 1E batteries. Class 1E battery maintenance and service testing is performed in conformance with Regulatory Guide 1.129. Batteries are inspected periodically to verify proper electrolyte levels, specific gravity, cell temperature, and battery float voltage. Cells are inspected in conformance with IEEE 450, and vendor recommendations.

The clearing of ground faults on the Class 1E dc system is also addressed by procedure. The battery testing procedures are written in conformance with IEEE 450 and the Technical Specifications.

Procedures are established for periodic testing of the Class 1E battery chargers and Class 1E voltage regulating transformers in accordance with the manufacturer recommendations.

- Circuit breakers in the Class 1E battery chargers and Class 1E voltage regulating transformers that are credited for an isolation function are tested through the use of breaker test equipment. This verification confirms the ability of the circuit to perform the designed coordination and corresponding isolation function between Class 1E and non-Class 1E components. Circuit breaker testing is done as part of the Maintenance Rule program and testing frequency is determined by that program.
- Fuses/fuse holders that are included in the isolation circuit are visually inspected.
- Class 1E battery chargers are tested to verify current limiting characteristic utilizing manufacturer recommendation and industry practices. Testing frequency is in accordance with that of the associated battery.

8.3.2.2 Analysis

Replace the first sentence of the third paragraph of DCD Subsection 8.3.2.2 with the following:

STD DEP 8.3-1 The Class 1E battery chargers are designed to limit the input (ac) current to an acceptable value under faulted conditions on the output side, however, the voltage regulating transformers do not have active components to limit current; therefore, the Class 1E voltage regulating transformer maximum current is determined by the impedance of the transformer.

8.3.3 COMBINED LICENSE INFORMATION FOR ONSITE ELECTRICAL POWER

PTN COL 8.3-1 This COL item is addressed in Subsections 8.3.1.1.7 and 8.3.1.1.8.

STD COL 8.3-2 This COL item is addressed in Subsections 8.3.1.1.2.4, 8.3.1.1.6 and 8.3.2.1.4.

8.3.4 REFERENCES

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201. Institute of Electrical and Electronics Engineers, *IEEE Guide for Safety in AC Substation Grounding*, IEEE Std 80-2000, August 4, 2000.

202. National Fire Protection Association, *Standard for the Installation of Lightning Protection Systems*, NFPA 780, 2008 ed.

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CHAPTER 9 AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9.1.3.1.3.1 Partial Core

Add the following information at the end of the third bullet in DCD Subsection 9.1.3.1.3.1.

PTN DEP 2.0-3

SFS performance following restart after a normal refueling is affected by a change in maximum safety wet bulb temperature. Calculations confirm that spent fuel pool temperature remains below 115°F with a CCS supply temperature of 97°F at the specified spent fuel pool loading condition and decay time on the fuel fraction just replaced during the previous 17-day refueling outage.

While the maximum CCS temperature expected for Turkey Point Units 6 & 7 is 97.4°F, an increase of 0.4°F in CCS supply temperature will produce a similar increase in the spent fuel pool maximum temperature; therefore, the requirement to maintain spent fuel temperature below 120°F is met with margin.

9.1.3.7 Instrumentation Requirements

Add the following paragraph after the first paragraph of DCD Subsection 9.1.3.7.D.

PTN SUP 9.1-1

All three safety-related spent fuel pool level instruments and associated instrument tubing lines are located below the fuel handling area operating deck and the cask washdown pit. This location provides protection from missiles that may result from damage to the structure over the spent fuel pool. The SFP level instruments associated with PMS divisions A and C are physically separated from the SFP level instrument associated with PMS division B. The safety-related spent fuel pool level instruments measure the water level from the top of the spent fuel pool to the top of the fuel racks. These instruments are conservatively calibrated

at a reference temperature suitable for normal spent fuel pool operation on a regular basis and accuracy is not affected by power interruptions.

9.1.4.3.8 Radiation Monitoring

STD COL 9.1-6 Plant procedures require that an operating radiation monitor is mounted on any machine when it is handling fuel. Refer to DCD Subsection 11.5.6.4 for a discussion of augmented radiation monitoring during fuel handling operations.

9.1.4.4 Inspection and Testing Requirements

Add the following paragraph at the end of DCD Subsection 9.1.4.4.

STD COL 9.1-5 The above requirements are part of the plant inspection program for the light load handling system, which is implemented through procedures. In addition to the above inspections, the procedures reflect the manufacturers' recommendations for inspection.

The light load handling program, including system inspections, is implemented prior to receipt of fuel onsite.

9.1.5 OVERHEAD HEAVY LOAD HANDLING SYSTEMS

Add the following at the end of DCD Subsection 9.1.5.

STD SUP 9.1-2 The heavy loads handling program is based on NUREG 0612 and vendor recommendations. The key elements of the program are:

- Listing of heavy loads to be lifted during operation of the plant. This list will be provided once magnitudes have been accurately formalized but no later than three (3) months prior to fuel receipt.

- Listing of heavy load handling equipment as outlined in DCD Table 9.1-5 and whose characteristics are described in Subsection 9.1.5 of the DCD.

- Heavy load handling safe load paths and routing plans including descriptions of interlocks, (automatic and manual) safety devices and procedures to assure safe load path compliance. Anticipated heavy load movements are analyzed and safe load paths defined. Safe load path considerations are based on comparison with analyzed cases, previously defined safe movement areas, and previously defined restricted areas. The analyses are in accordance with Appendix A of NUREG 0612.

- Heavy load handling equipment maintenance manuals and procedures as described in Subsection 9.1.5.5.

- Heavy load handling equipment inspection and test plans, as outlined in Subsections 9.1.5.4 and 9.1.5.5.

- Heavy load handling personnel qualifications, training, and control procedures as described in Subsection 9.1.5.5.

- QA programs to monitor, implement, and ensure compliance with the heavy load-handling procedures as described in Subsection 9.1.5.5.

A quality assurance program, consistent with Paragraph 10 of NUREG-0554, is established and implemented for the procurement, design, fabrication, installation, inspection, testing, and operation of the crane. The program, as a minimum, includes the following elements:

- design and procurement document control

- instructions, procedures, and drawings

- control of purchased material, equipment, and services

- inspection

- testing and test control

- non-conforming items

- corrective action

- records

9.1.5.3 Safety Evaluation

Add the following information at the end of DCD Subsection 9.1.5.3.

STD SUP 9.1-1 There are no planned heavy load lifts outside those already described in the DCD. However, over the plant life there may be occasions when heavy loads not presently addressed need to be lifted (i.e. in support of special maintenance/ repairs). For these occasions, special procedures are generated that address, as a minimum, the following:

- The special procedure complies with NUREG-0612.
- A safe load path is determined. Mechanical and/or electrical stops are incorporated in the hardware design to prohibit travel outside the safe load path. Maximum lift heights are specified to minimize the impact of an unlikely load drop.
- Where a load drop could occur over irradiated fuel or safe shutdown equipment, the consequence of the load drop is evaluated. If the evaluation concludes that the load drop is not acceptable, an alternate path is evaluated, or the lift is prohibited.
- The lifting equipment is in compliance with applicable ANSI standards and has factors of safety that meet or exceed the requirements of the applicable standards.
- Operator training is provided prior to actual lifts.
- Inspection of crane components is performed in accordance with the manufacturer recommendations.

STD COL 9.1-6 Plant procedures require that an operating radiation monitor is mounted on any crane when it is handling fuel. Refer to DCD Subsection 11.5.6.4 for a discussion of augmented radiation monitoring during fuel handling operations.

9.1.5.4 Inservice Inspection/Inservice Testing

Add the following paragraph at the end of DCD Subsection 9.1.5.4.

STD COL 9.1-5 The above requirements are part of the plant inspection program for the overhead heavy load handling system, which is implemented through procedures. In addition to the above inspections, the procedures reflect the manufacturers' recommendations for inspection and the NUREG-0612 recommendations.

The overhead heavy load handling equipment inservice inspection procedures, as a minimum, address the following:

- Identification of components to be examined
- Examination techniques
- Inspection intervals
- Examination categories and requirements
- Evaluation of examination results

The overhead heavy load handling program, including system inspections, is implemented prior to receipt of fuel onsite.

9.1.5.5 Load Handling Procedures

STD SUP 9.1-3 Load handling operations for heavy loads that are handled over, could be handled over or are in the proximity of irradiated fuel or safe shutdown equipment are controlled by written procedures. As a minimum, procedures are used for handling loads with the spent fuel cask bridge and polar cranes, and for those loads listed in Table 3.1-1 of NUREG 0612. The procedures include and address the following elements:

- The specific equipment required to handle load (e.g., special lifting devices, slings, shackles, turnbuckles, clevises, load cells, etc.).

- Qualification and training of crane operators and riggers in accordance with chapter 2-3.1 of ASME B30.2, "Overhead and Gantry Cranes."
- The requirements for inspection and acceptance criteria prior to load movement.
- The defined safe load path and provisions to provide visual reference to the crane operator and/or signal person of the safe load path envelope.
- Specific steps and proper sequence to be followed for handling load.
- Precautions, limitations, prerequisites, and/or initial conditions associated with movement of heavy loads.
- The testing, inspection, acceptance criteria and maintenance of overhead heavy load handling systems. These procedures are in accordance with the manufacturer recommendations and are consistent with ANSI B30.2 or with other appropriate and applicable ANSI standards.

Safe load paths are defined for movement of heavy loads to minimize the potential for a load drop on irradiated fuel in the reactor vessel, spent fuel pool or safe shutdown equipment. Paths are defined clearly in procedures and equipment layout drawings. Equipment layout drawings showing the safe load path are used to define safe load paths in load handling procedures. Deviation from defined safe load paths requires a written alternative procedure approved by a plant safety review committee.

9.1.6 COMBINED LICENSE INFORMATION FOR FUEL STORAGE AND HANDLING

9.1.6.5 Inservice Inspection Load Handling Systems

STD COL 9.1-5 This COL Item is addressed in Subsections 9.1.4.4 and 9.1.5.4.

9.1.6.6 Operating Radiation Monitor

STD COL 9.1-6 This COL Item is addressed in Subsections 9.1.4.3.8 and 9.1.5.3.

9.1.6.7 Coupon Monitoring Program

STD COL 9.1-7 A spent fuel rack Metamic coupon monitoring program is to be implemented when the plant is placed into commercial operation. This program will include tests to monitor bubbling, blistering, cracking, or flaking; and a test to monitor for corrosion, such as weight loss measurements and/or visual examination. The program will also include testing to monitor changes in physical properties of the absorber material, including neutron attenuation and thickness measurements.

The program will include the methodology and acceptance criteria for the tests listed and provide corrective action requirements based on vendor recommendations and industry operating experience. The program will be implemented through plant procedures.

Metamic Monitoring Acceptance Criteria:

- Verification of continued presence of the boron is performed by neutron attenuation measurement. A decrease of no more than 5% in Boron-10 content, as determined by neutron attenuation, is acceptable. This is equivalent to a requirement for no loss in boron within the accuracy of the measurement.

- Coupons are monitored for unacceptable swelling by measuring coupon thickness. An increase in coupon thickness at any point of no more than 10% of the initial thickness at that point is acceptable.

Changes in excess of either of the above two acceptance criteria are investigated under the corrective action program and may require early retrieval and measurement of one or more of the remaining coupons to provide validation that the indicated changes are real. If the deviation is determined to be real, an engineering evaluation is performed to identify further testing or any corrective action that may be necessary.

Additional parameters are examined for early indications of the potential onset of Metamic degradation that would suggest a need for further attention and possibly a change in the coupon withdrawal schedule. These include visual inspection for

surface pitting, blistering, cracking, corrosion or edge deterioration, or unaccountable weight loss in excess of the measurement accuracy.

9.2 WATER SYSTEMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9.2.1.2 System Description

Add the following paragraph to the end of the Cooling Tower subsection in DCD Subsection 9.2.1.2.2.

PTN SUP 9.2-1 The SWS Cooling Tower was evaluated for potential impacts from interference and air restriction effects due to yard equipment layout and tower operation in an adjacent unit. Based on unit spacing, yard equipment layout, and the margins inherent in the performance requirements and design conditions of the towers, no adverse impacts were determined.

Replace the paragraph in DCD Subsection 9.2.1.2.3.4 with the following paragraph.

PTN DEP 2.0-2 During the plant cooldown phase in which the normal residual heat removal system has been placed in service and is providing shutdown cooling, the service water cooling tower provides cooling water at a temperature of 89.8°F or less when operating at design heat load and at an ambient wet bulb temperature of no greater than the maximum normal wet bulb temperature as defined in Chapter 2, Table 2.0-201. Two service water pumps and two cooling tower cells are normally used for plant cooldown, and the cross-connection valves between trains are normally closed. The service water system heat load and flow rate are shown in DCD Table 9.2.1-1. During these modes of operation the normal residual heat removal system and the component cooling water system remove sensible and decay heat from the reactor coolant system. The service water system cooling towers are designed with sufficient margin so that normal time-related degradation of tower performance will not prohibit their support of this heat removal function. In the event of failure of a service water system pump or cooling tower fan, the cooldown time is extended.

9.2.2.1 Design Bases

Replace the first bullet item in the criteria for normal operation in DCD Subsection 9.2.2.1.2.1 with the following information.

PTN DEP 2.0-3

- The component cooling water supply temperature to plant components is not more than 100°F assuming a 100-year return estimate of 2-hour duration wet bulb temperature of 87.4°F for service water cooling (per Table 2.0-201).

  The most limiting component cooled by the CCS, the RCP motor cooling system, has been designed to operate for at least 6 hours continually with cooling water supplied at temperatures up to 100°F.

  The performance of the standard AP1000 CCS and SWS for single cooling water train, full power operation at a maximum safety wet bulb temperature of 87.4°F has demonstrated the highest CCS temperature achieved at these conditions is 97.4°F, for a period of less than 2 hours. As ambient wet bulb temperature decreases, the CCS temperature follows and will return to below 95°F with ambient wet bulb temperature slightly lower than 84°F, assuming nominal performance of both the CCS and SWS. Since the definition of the maximum normal wet bulb temperature value is the seasonal 1 percent exceedance value observed at the site, the annual total operating time for which CCS temperature could exceed 95°F is less than 30 hours per year, for periods of a few hours at most. The maximum CCS temperature of 97.4°F is bounded by the maximum allowable cooling water temperature for reactor coolant pumps (the most limiting component) and the increase in maximum safety wet bulb temperature is therefore acceptable on this basis.

9.2.5.2.1 General Description

Delete the third sentence of the second paragraph and replace the first sentence of the second paragraph of DCD Subsection 9.2.5.2.1 with the following sentence.

PTN COL 9.2-1

The source of water for the potable water system is the Miami-Dade Water and Sewer Department (MDWASD) potable water supply.

9.2.5.3 System Operation

Replace the first and second paragraphs of DCD Subsection 9.2.5.3 with the following information.

PTN COL 9.2-1 The MDWASD potable water supply system provides filtered and disinfected water to the potable water distribution system.

The MDWASD potable water supply system maintains the required pressure throughout the potable water distribution system. The source of potable water meets the EPA drinking water standards. No biocide or other water treatment is required.

9.2.6.1.1 Safety Design Basis

Revise the first sentence of the first paragraph of DCD Subsection 9.2.6.1.1 to read as follows:

PTN DEP 6.4-1 The sanitary drainage system isolates the SDS vent penetration in the main control room boundary on High-2 particulate or iodine concentrations in the main control room air supply or on extended loss of ac power to support operation of the main control room emergency habitability system as described in Section 6.4.

9.2.6.2.1 General Description

Add the following text to the end of DCD Subsection 9.2.6.2.1.

PTN SUP 9.2-3 Sanitary waste is treated on the Units 6 & 7 plant area. The treatment facility has the capacity to treat the waste from Units 1 through 7. The liquid effluent from the sanitary treatment facility is pumped to the blowdown sump where it combines with other effluent streams.

9.2.7.2 System Description

Replace the second paragraph of DCD Subsection 9.2.7.2.1 with the following:

PTN DEP 2.0-2

The high capacity subsystem consists of two 80-percent capacity chilled water pumps, two 20-percent capacity chilled water pumps, two 80-percent capacity water-cooled chillers, two 20-percent air-cooled chillers, a chemical feed tank, an expansion tank, and associated valves, piping, and instrumentation. The subsystem is arranged in two parallel mechanical trains with common supply and return headers. Each train includes one 20-percent capacity pump, one 80-percent capacity pump, one 20-percent capacity chiller, and one 80-percent capacity chiller. A cross-connection at the discharge of each pump allows for each to feed a given chiller of matching capacity.

Replace the last sentence of the first paragraph of DCD Subsection 9.2.7.2.2 with the following sentence:

PTN DEP 2.0-2

The key equipment parameters for the central chilled water system components are contained in Table 9.2.7-1R.

9.2.7.2.4 System Operation

Add the following information at the end of the first paragraph under “Normal Operation” in DCD Subsection 9.2.7.2.4.

PTN DEP 2.0-3

The increased heat load produced by operation at the higher Turkey Point Units 6 & 7 maximum safety ambient wet bulb temperature of 87.4°F can be accommodated within the available capacity margin of the chiller units, without impacting the VWS low capacity subsystem or supporting systems design or plant operation. Cooling coil design calculations indicate that during operation at the standard plant design temperatures (115°F dry bulb, 86.1°F wet bulb), the VBS air handling unit has cooling coil and system margin.

Replace the last sentence of the third paragraph of the Abnormal Operation subsection in DCD Subsection 9.2.7.2.4 with the following sentence:

PTN DEP 2.0-2

Following the loss of offsite power, one diesel generator and one train of the low capacity subsystem operate to supply chilled water to the associated cooling coils of the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers as shown in Table 9.2.7-1R.

Subsection 9.2.8 is modified using full text incorporation to provide site-specific information to replace the DCD conceptual design information (CDI).

9.2.8 TURBINE BUILDING CLOSED COOLING WATER SYSTEM

PTN CDI

The turbine building closed cooling water system (TCS) provides chemically treated, demineralized cooling water for the removal of heat from nonsafety-related heat exchangers in the turbine building and rejects the heat to the circulating water system.

9.2.8.1 Design Basis

9.2.8.1.1 Safety Design Basis

DCD

The turbine building closed cooling water system has no safety-related function and therefore has no nuclear safety design basis.

9.2.8.1.2 Power Generation Design Basis

The turbine building closed cooling water system provides corrosion-inhibited, demineralized cooling water to the equipment shown in Table 9.2.8-1 during normal plant operation.

PTN CDI

During power operation, the turbine building closed cooling water system provides a continuous supply of cooling water to turbine building equipment at a temperature of 105°F or less assuming a circulating water temperature of 100°F or less.

DCD

The cooling water is treated with a corrosion inhibitor and uses demineralized water for makeup. The system is equipped with a chemical addition tank to add chemicals to the system.

PTN CDI

The heat sink for the turbine building closed cooling water system is the circulating water system. The heat is transferred to circulating water through plate type heat exchangers which are components of the turbine building closed cooling water system.

DCD

A surge tank is sized to accommodate thermal expansion and contraction of the fluid due to temperature changes in the system.

One of the turbine building closed cooling system pumps or heat exchangers may be unavailable for operation or isolated for maintenance without impairing the function of the system.

The turbine building closed cooling water pumps are provided ac power from the 6900V switchgear bus. The pumps are not required during a loss of normal ac power.

9.2.8.2 System Description

9.2.8.2.1 General Description

PTN CDI

Classification of equipment and components is given in Section 3.2. The system consists of two 100-percent capacity pumps, three 50-percent capacity heat exchangers (connected in parallel), one surge tank, one chemical addition tank, and associated piping, valves, controls, and instrumentation. Heat is removed from the turbine building closed cooling water system by the circulating water system via the heat exchangers.

DCD

The pumps take suction from a single return header. Either of the two pumps can operate in conjunction with any two of the three heat exchangers. Discharge flows from the heat exchangers combine into a single supply header. Branch lines then distribute the cooling water to the various coolers in the turbine building. The flow rates to the individual coolers are controlled either by flow restricting orifices or by control valves, according to the requirements of the cooled systems. Individual coolers can be locally isolated, where required, to permit maintenance of the cooler while supplying the remaining components with cooling water. A bypass line with a manual valve is provided around the turbine building closed cooling water system heat exchangers to help avoid overcooling of components during startup/low-load conditions or cold weather operation.

The system is kept full of demineralized water by a surge tank which is located at the highest point in the system. The surge tank connects to the system return header upstream of the pumps. The surge tank accommodates thermal expansion and contraction of cooling water resulting from temperature changes in the system. It also accommodates minor leakage into or out of the system. Water makeup to the surge tank, for initial system filling or to accommodate leakage from the system, is provided by the demineralized water transfer and storage system. The surge tank is vented to the atmosphere.

A line from the pump discharge header back to the pump suction header contains valves and a chemical addition tank to facilitate mixing chemicals into the closed loop system to inhibit corrosion in piping and components.

A turbine building closed cooling water sample is periodically taken and analyzed to verify that water quality is maintained.

9.2.8.2.2 Component Description

Surge Tank

A surge tank accommodates changes in the cooling water volume due to changes in operating temperature. The tank also temporarily accommodates leakage into or out of the system. The tank is constructed of carbon steel.

Chemical Addition Tank

The chemical addition tank is constructed of carbon steel. The tank is normally isolated from the system and is provided with a hinged closure for addition of chemicals.

Pumps

Two pumps are provided. Either pump provides the pumping capacity for circulation of cooling water throughout the system. The pumps are single stage, horizontal, centrifugal pumps, are constructed of carbon steel, and have flanged suction and discharge nozzles. Each pump is driven by an ac powered induction motor.

Heat Exchangers

Three heat exchangers are arranged in a parallel configuration. Two of the heat exchangers are in use during normal power operation and turbine building closed cooling water flow divides between them.

PTN CDI

The heat exchangers are plate type heat exchangers. Turbine building closed cooling water circulates through one side of the heat exchanger while circulating water flows through the other side. During system operation, the turbine building closed cooling water in the heat exchanger is maintained at a higher pressure than the circulating water so leakage of circulating water into the closed cooling water system does not occur. The heat exchangers are constructed of titanium plates with a carbon steel frame.

Valves

DCD

Manual isolation valves are provided upstream and downstream of each pump. The pump isolation valves are normally open but may be closed to isolate the non-operating pump and allow maintenance during system operation. Manual isolation valves are provided upstream and downstream of each turbine building closed cooling water heat exchanger. One heat exchanger is isolated from system flow during normal power operation. A manual bypass valve can be opened to bypass flow around the turbine building closed cooling water heat exchangers when necessary to avoid low cooling water supply temperatures.

Flow control valves are provided to restrict or shut off cooling water flow to those cooled components whose function could be impaired by overcooling. The flow control valves are air operated and fail open upon loss of control air or electrical power. An air operated valve is provided to control demineralized makeup water to the surge tank for system filling and for accommodating leakage from the system. The makeup valve fails closed upon loss of control air or electrical power.

A TCS heat exchanger can be taken out of service by closing the inlet isolation valve. Water chemistry in the isolated heat exchanger train is maintained by a continuous flow of circulating water through a small bypass valve around the inlet isolation valve.

Backwashable strainers are provided upstream of each TCS heat exchanger. They are actuated by a timer and have a backup starting sequence initiated by a high differential pressure across each individual strainer. The backwash can be manually activated.

Piping

System piping is made of carbon steel. Piping joints and connections are welded, except where flanged connections are used for accessibility and maintenance of components. Nonmetallic piping also may be used.

9.2.8.2.3 System Operation

The turbine building closed cooling water system operates during normal power operation. The system does not operate with a loss of normal ac power.

Startup

PTN CDI

The turbine building closed cooling water system is placed in operation during the plant startup sequence after the circulating water system is in operation but prior to the operation of systems that require turbine building closed cooling water flow. The system is filled by the demineralized water transfer and storage system through a fill line to the surge tank. The system is placed in operation by starting one of the pumps.

DCD

Normal Operation

During normal operation, one turbine building closed cooling water system pump and two heat exchangers provide cooling to the components listed in Table 9.2.8-1. The other pump is on standby and aligned to start automatically upon low discharge header pressure.

During normal operation, leakage from the system will be replaced by makeup from the demineralized water transfer and storage system through the automatic makeup valve. Makeup can be controlled either manually or automatically upon reaching low level in the surge tank.

Shutdown

The system is taken out of service during plant shutdown when no longer needed by the components being cooled. The standby pump is taken out of automatic control, and the operating pump is stopped.

9.2.8.3 Safety Evaluation

The turbine building closed cooling water system has no safety-related function and therefore requires no nuclear safety evaluation.

9.2.8.4 Tests and Inspections

Pre-operational testing is described in Chapter 14. The performance, structural, and leaktight integrity of system components is demonstrated by operation of the system.

9.2.8.5 Instrument Applications

Parameters important to system operation are monitored in the main control room. Flow indication is provided for individual cooled components as well as for the total system flow.

Temperature indication is provided for locations upstream and downstream of the turbine building closed cooling water system heat exchangers. High temperature of the cooling water supply alarms in the main control room. Temperature test points are provided at locations to facilitate thermal performance testing.

Pressure indication is provided for the pump suction and discharge headers. Low pressure at the discharge header automatically starts the standby pump.

Level instrumentation on the surge tank provides level indication and both low- and high-level alarms in the main control room. On low tank level, a valve in the makeup water line automatically actuates to provide makeup flow from the demineralized water transfer and storage system.

9.2.9.2.2 Component Description

Replace the paragraph under the heading Waste Water Retention Basin in DCD Subsection 9.2.9.2.2 with the following text.

PTN COL 9.2-2

The wastewater retention basin, located west of the turbine building for each unit, is a lined basin with two compartments constructed such that its contents (dissolved or suspended), do not penetrate the liner and leach into the ground. Either of these compartments can receive waste streams for holdup or, if required, for treatment to meet specific environmental discharge requirements.

The configuration and size of the wastewater retention basin allows settling of solids larger than 10 microns which may be suspended in the wastewater stream.

Wastewater can be sampled before it is discharged from the wastewater retention basin.

Basin Transfer Pumps

Two 100-percent capacity submersible type pumps, one per basin compartment, send the wastewater from the retention basin to the blowdown sump. Each pump is sized to meet the maximum expected influent flow to prevent overflow of the basin. In the event of oily waste leakage into the retention basin, a recirculation line is provided to recycle the oil/water waste from the basin to the oil separator in the turbine building. In the event of radioactive contamination, this same line can be used to send the contents of the basin to the liquid radwaste system (WLS). Controls are provided for automatic or manual operation of the pumps based on the level of the retention basin.

Add the following text at the end of DCD Subsection 9.2.9.2.2.

PTN SUP 9.2-4 Blowdown Sump

The blowdown sump is a lined concrete structure common to Units 6 & 7 that receives wastewater from the wastewater retention basins of both units, circulating water system (CWS) blowdown from both units, and effluent from the sanitary treatment facility. The blowdown sump is located southeast of the units near the makeup water reservoir. In the absence of CWS blowdown, dilution flow can be supplied to the blowdown sump from the raw water system (reclaimed water or saltwater sources). The waste stream from the blowdown sump is pumped to the deep injection wells. The pumps, downstream piping, and injection wells are part of the deep well injection system (DIS) described in Subsection 9.2.12. The blowdown sump, injection pumping station and associated piping to the injection wells is sized with adequate capacity to accommodate the highest expected influent flow rate to the blowdown sump without overflowing of the sump.

9.2.9.5 Instrumentation Applications

Add the following after the first paragraph of DCD Subsection 9.2.9.5.

PTN COL 9.2-2 Level instrumentation is provided at the wastewater retention basin and is used to control operation of the basin transfer pumps. High-level alarms indicate the basin level where operator action is required.

PTN SUP 9.2-5 Level instrumentation is provided at the blowdown sump and is used to control operation of the pumps discharging to the deep injection wells. A high level alarm indicates the sump level where operator action is required.

STD DEP 1.1-1 Add the following subsections after DCD Subsection 9.2.10. DCD Subsections 9.2.11 and 9.2.12 are renumbered as Subsections 9.2.13 and 9.2.14, respectively.

9.2.11 RAW WATER SYSTEM

PTN SUP 9.2-2 The raw water system (RWS) provides makeup to the circulating water mechanical draft cooling tower basins, demineralized water treatment system, raw water storage tank, the fire protection system fire water storage tanks, and service water cooling tower basins.

9.2.11.1 Design Basis

9.2.11.1.1 Safety Design Basis

The RWS has no safety-related function and therefore has no nuclear safety design basis.

Failure of the RWS or its components does not affect the ability of safety-related systems to perform their intended function.

The RWS does not have the potential to be a flow path for radioactive fluids.

9.2.11.1.2 Power Generation Design Basis

9.2.11.1.2.1 Normal Operation

The RWS provides a continuous supply of makeup water from 3 separate sources to the following services: (Figure 9.2-201 shows which sources supply which services).

- Circulating water system fill and makeup (sources: reclaimed water and/or saltwater)
- SWS fill and makeup (source: potable water)
- Demineralized water treatment system feed (source: potable water)

In addition, the RWS performs the following functions (Figure 9.2-201 shows which sources supply which functions):

- Filling the fire protection system fire water storage tanks (source: potable water)
- Providing the water for miscellaneous plant uses such as strainer backwash and media filter backwashes (source: potable water)
- Providing dilution flow required for liquid radwaste discharge (sources: reclaimed water and/or saltwater)

9.2.11.1.2.2 Outage Mode Operation

During plant outages, the RWS provides water to the same services as during normal operation with the exception of circulating water system makeup.

9.2.11.2 System Description

9.2.11.2.1 General Description

The RWS is shown in Figure 9.2-201 (Sheets 1–3). Classification of components and equipment for the RWS is given in Section 3.2.

9.2.11.2.1.1 Reclaimed Water

One of the sources of makeup water for the circulating water system is reclaimed water supplied to the FPL reclaimed water treatment facility from the MDWASD. From the FPL reclaimed water treatment facility, the reclaimed water is stored in the makeup water reservoir before being pumped to the circulating water system cooling tower basins. This arrangement is shown on Figure 9.2-201, Sheet 1 of 3.

9.2.11.2.1.2 Saltwater

The other source available for makeup water to the circulating water system is saltwater supplied from substratum radial collector wells. These wells pump saltwater that recharges from the marine environment (Biscayne Bay). Saltwater

is used when a sufficient quantity and/or quality of treated reclaimed water is unavailable. This arrangement is shown in Figure 9.2-201, Sheet 2 of 3.

9.2.11.2.1.3 Potable Water

The MDWASD potable water supply provides water to the raw water storage tank. The raw water storage tank provides makeup water for the service water cooling towers. Additionally, the raw water storage tank also provides water for the fire protection system, demineralized water treatment system and other miscellaneous users. This arrangement is shown on Figure 9.2-201, Sheet 3 of 3.

9.2.11.2.2 Component Description

9.2.11.2.2.1 Components Handling Reclaimed Water

FPL Reclaimed Water Treatment Facility

The FPL reclaimed water treatment facility is designed to remove constituents from the sewage wastewater treatment plant in order to use it in the circulating water system. The FPL reclaimed water treatment facility includes pumps, trickling filters, clarifiers, deep bed filters, and solids handling equipment to reduce the levels of iron, magnesium, oil and grease, total suspended solids, nutrients, and silica to usable levels for the circulating water system.

Makeup Water Reservoir

The makeup water reservoir is used to store cooling water from the FPL reclaimed water treatment facility to be used as makeup to the circulating water system.

Reclaimed Makeup Water Pumps

Three 50-percent reclaimed makeup water pumps per unit are provided to supply reclaimed water from the makeup water reservoir for the services and functions listed in Subsection 9.2.11.1.2. They are powered from the normal ac power system.

Piping

The piping is designed to accommodate transient effects that may be generated by normal starting and stopping of pumps, opening and closing of valves, or other normal operating events. Air release valves are provided in the reclaimed makeup water pump discharge piping to vent air on pump start.

Screens

Coarse and fine screens are installed on the inlet to each reclaimed makeup water pump to prevent debris in the makeup water reservoir from entering the pump bay.

9.2.11.2.2.2 Components Handling Saltwater

Radial Collector Wells

Saltwater is supplied by four radial collector wells for the two units. A radial collector well consists of a central reinforced concrete caisson extending below ground level. Screens extend from the caisson laterally below Biscayne Bay. The wells are designed and sited to induce recharge from Biscayne Bay.

Saltwater Makeup Pumps

Four 33 1/3-percent saltwater makeup pumps per unit are provided to supply saltwater for the services and functions listed in Subsection 9.2.11.1.2. Each pump discharge line has a motor-operated valve located between the pump discharge and the output header to permit isolation of the pump. Two pumps are provided in each of the four radial collector wells for the two units. The pumps are powered from the normal ac power system.

Piping and Valves

The piping is designed to accommodate transient effects that may be generated by normal starting and stopping of pumps, opening and closing of valves, or other normal operating events. Air release valves are provided in the saltwater makeup pump discharge piping to vent air on pump start. Motor-operated valves are provided to direct the flow as required.

9.2.11.2.2.3 Components Handling Potable Water

Raw Water Storage Tank

A raw water storage tank is provided for Units 6 & 7. This tank receives water from the MDWASD potable water supply. The tank includes features to prevent contamination of the potable water supply by the tank contents. Should the potable water supply to the storage tank be interrupted, the volume of water in the tank (a minimum of two million gallons) provides sufficient time to facilitate a temporary supply of water to the service water cooling tower basins from another on-site water source, such as water from the makeup water reservoir (MWR). The

MWR has a capacity well in excess of that needed to support cooldown to cold shutdown conditions and maintain the station in Mode 5 for greater than 7 days.

Raw Water Ancillary Pumps

Two 100-percent raw water ancillary pumps per unit draw water from the raw water storage tank to supply the required flow for the services and functions listed in Subsection 9.2.11.1.2. They are powered from the normal ac power system. The raw water ancillary pumps can be manually loaded onto the standby diesel generators to provide makeup to the service water cooling tower basins, if necessary, following a loss of normal ac power.

Piping

The piping is designed to accommodate transient effects that may be generated by normal starting and stopping of pumps, opening and closing of valves, or other normal operating events. Air release valves are provided in the raw water ancillary pump discharge piping to vent air on pump start.

9.2.11.3 System Operation

The RWS operates during normal modes of operation, including startup, power operation, cooldown, shutdown, and refueling.

Reclaimed water from the MDWASD supplies makeup water for the circulating water system of Units 6 & 7. Saltwater, from radial collector wells, also provides makeup water to the cooling tower basins. The circulating water system is designed to accommodate 100-percent supply from reclaimed water, saltwater, or a combination of the two sources. The ratio of water supplied by the two makeup water sources varies based on the availability of reclaimed water from the MDWASD.

Makeup water for the service water system makeup is supplied by the MDWASD potable water supply to the raw water storage tank. This water is also the source for demineralized water, fire protection, and miscellaneous water users.

9.2.11.4 Safety Evaluation

The RWS has no safety-related function and therefore requires no nuclear safety evaluation.

The RWS does not have the potential to be a flow path for radioactive fluids. The RWS has no direct interconnection with any system that contains licensed

radioactive fluids. The liquid radwaste effluent interface is at a point in the DIS that prevents the effluent from entering the RWS.

9.2.11.5 Tests and Inspections

Initial test requirements for the RWS are described in Subsection 14.2.9.4.24.

System performance and structural and pressure integrity of system components is demonstrated by operation of the system, monitoring of system parameters such as flow and pressure, and visual inspections.

9.2.11.6 Instrumentation Applications

Pressure indication, with low and high alarms, is provided on the discharges of the raw water pumps. A low discharge pressure signal automatically starts the designated standby pump. Pressure indication, alarms, and controls for pumps included in the FPL reclaimed water treatment facility ensure the required pressure and flow of the raw water supply from the FPL reclaimed water treatment facility.

Level instrumentation is provided at the raw water storage tank to allow the tank level to be monitored and to control the flow of the MDWASD supplied potable water to the tank. Abnormally high or low water levels in the tank will be alarmed in the control room.

Level instrumentation on the fire water tanks automatically opens the fill valve on low tank level and closes on high level.

Instrumentation requirements for makeup to the SWS and CWS cooling tower basins are described in DCD Subsection 9.2.1 and FSAR Subsection 10.4.5, respectively.

STD DEP 1.1-1

9.2.12 DEEP WELL INJECTION SYSTEM

PTN SUP 9.2-2

The DIS provides underground disposal of plant wastewater, including CWS blowdown and liquid radwaste, into the Boulder Zone. The system consists of 12 deep injection wells, 6 dual-zone monitoring wells, piping, valving, pumps, and instrumentation for system operational monitoring.

Dilution of the liquid radwaste is initiated as the radwaste enters the DIS in the discharge stream from the blowdown sump. The content of the blowdown sump is a combination of waste streams largely comprised of reclaimed water or saltwater from circulating water system blowdown during plant operation or from the alternate dilution flow paths when circulating water system blowdown is not sufficient or available for dilution. The DIS is shown in Figure 9.2-203.

The alternate dilution flow, when using reclaimed water as the cooling water makeup source, is reclaimed water supplied from the makeup water reservoir. The makeup water reservoir is a concrete structure that contains between 275 and 300 million gallons of reclaimed water that is available for use as makeup for the cooling tower evaporative, drift, and blowdown losses and the alternate dilution flow to achieve a DCD-referenced nominal 12,000 gpm dilution flow. The reservoir contains approximately 5 days of makeup water to supply both units' cooling towers operating at full power.

9.2.12.1 Design Basis

9.2.12.1.1 Safety Design Basis

The DIS has no safety-related function and therefore has no nuclear safety design basis.

Failure of the DIS does not affect the ability of safety-related systems to perform their intended function. The DIS functions to dispose and confine plant wastewater in the Boulder Zone.

The DIS is a flow path for liquid radwaste and liquid nonradioactive waste discharge.

9.2.12.1.2 Power Generation Design Basis

9.2.12.1.2.1 Normal Operation

DIS operations maintain the required minimum dilution factor to control the concentrations of liquid radwaste discharges arising from the release of WLS monitor tank contents. The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, effluent concentration limits (ECLs) by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied before the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture

complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), an operational program identified in Table 13.4-201.

9.2.12.1.2.1.1 Reclaimed Water

The deep well injection flow rate when 100 percent reclaimed water is in use for cooling is nominally approximately 12,500 gallons per minute (gpm) (normal) and 13,000 gpm (maximum) for both units. The liquid radwaste component of this flow rate is 3 gpm (normal) and 150 gpm (maximum) for both units. Three deep injection wells are sufficient for reclaimed water—two active and one as a backup.

9.2.12.1.2.1.2 Saltwater

The deep well injection flow rate when 100 percent saltwater is in use for cooling is nominally approximately 58,000 gpm (normal) and 59,000 gpm (maximum) for both units. The liquid radwaste component of this flow rate is 3 gpm (nominal) and 150 gpm (maximum) for both units. Eleven deep injection wells are sufficient for saltwater—nine active and two as backup.

9.2.12.1.2.2 Outage Mode Operation

Refer to Subsection 9.2.12.1.2.1.

9.2.12.2 System Description

The following system and component descriptions are typical. The actual system and components may vary.

9.2.12.2.1 General Description

The proposed locations of the deep injection wells and dual zone monitoring wells are depicted in Figure 9.2-202. The liquid waste stream collection and disposal schematic is shown in Figure 9.2-203. Classification of components and equipment for the DIS is given in Section 3.2. The operation of the DIS is identical for both reclaimed and saltwater—only the number of deep injection wells used differs. Additional valving and system monitoring is required for the system when saltwater is used as a makeup water since more deep injection wells are required because of the higher flow rates.

9.2.12.2.2 Component Description

Deep Injection Wells

Each of the deep injection wells is constructed with concentric steel casings to isolate and protect groundwater from injected fluid. Each injection well is constructed with new and unused 64- (or greater), 54-, 44-, 34-, and 24-inch-outside-diameter steel casings designed to last for the life expectancy of the well. The 64- (or greater), 54-, 44-, and 34-inch-diameter casings have a minimum wall thickness of 0.375 inches and conform to American Society for Testing and Material (ASTM) 139, Grade B specifications. The final 24-inch-diameter casing has a 0.5-inch wall thickness, is seamless, and conforms to American Petroleum Institute (API) 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations, protect against failure during operation of the well and subsequent pressure tests, and provide sufficient corrosion protection. The 54-, 44-, and 34-inch-diameter casings are encased in cement on both the outside and the inside of the casing to protect against exposure to groundwater. The outside of the 24-inch-diameter casing is encased in cement to protect against exposure to groundwater. A nominal 18-inch-diameter fiberglass reinforced plastic (FRP) injection tubing with a wall thickness of 0.76 inches is installed inside the 24-inch-diameter casing to protect the 24-inch-diameter casing from exposure to injected fluids and subsequent corrosion. The annular space between the 24-inch-diameter casing and the FRP injection tubing will be filled with a nonhazardous corrosion inhibitor and sealed at the base and top to create a pressure-tight annular space. Figure 9.2-204 depicts a typical deep injection well. This schematic is based on actual conditions observed at Deep Injection Well DIW-1.

Dual Zone Monitoring Wells

Each of the dual zone monitor wells is constructed with concentric steel casings and a final FRP casing. Each monitor well is constructed with new and unused 44-, 34-, 24-, 16-, and 6.625-inch-diameter casings/tubings designed to last for the life expectancy of the well. The 44-, 34-, and 24-inch-diameter casings are made of steel with a minimum wall thickness of 0.375 inches and conform to ASTM 139, Grade B specifications. The 16-inch-diameter casing is made of steel and has a 0.5-inch wall thickness, is seamless, and conforms to API 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations and provide sufficient corrosion protection for the life of the well. The 34- and 24-inch-diameter casings are encased in cement on both the outside and the inside of the casing to

protect against exposure to groundwater. The outside of the 16-inch-diameter casing is encased in cement to protect against exposure to groundwater. A nominal 6.625-inch-diameter FRP casing with a wall thickness of 0.27 inches serves as the final casing of the well and is selected due to its corrosion resistance. Figure 9.2-205 depicts a typical dual zone monitoring well.

The typical sampling system and associated equipment used for the dual zone monitoring wells are described below. The upper monitor zone sampling system is equipped with a surface-mounted centrifugal pump and the pump for the lower monitoring zone sampling system is a submersible turbine pump installed inside the lower monitor zone casing via a drop pipe. The pumps are connected to purge piping and have a totalizing flowmeter on each purge piping line. The totalizing flowmeters allow measurement of the volume of water that has been purged from the monitoring zones for each sampling event. A separate purge piping line and totalizing flowmeter is used for each monitoring zone to ensure against comingling of monitoring zone fluids. The purge water holding tank is located near the dual-zone monitoring well or on the containment pad of one of its two associated injection wells. The purge piping is buried as it leaves the monitoring well containment pad and either leads to the existing cooling canal system where it is released or it leads to a purge water holding tank. The upper zone and lower zone purge lines flow into the holding tank when the monitoring zones are being purged in preparation for sample collection. The holding tank is equipped with a pump and water level regulating system to ensure that the holding tank capacity is not exceeded. A pump is used to pump water from the holding tank to one of the associated deep injection wells, where it is pumped down the injection well and into the injection zone. The purge piping for each monitor zone is also connected to a sample collection sink that is located either on the monitor well containment pad or on the containment pad of one of the associated injection wells.

Considering the large depth of confining strata present above the injection zone (approximately 985 feet for DIW-1), it is highly unlikely that plant-derived radioactive contamination would be found in water produced in either monitor zone of the dual-zone monitor well. However, if plant-derived radioactive contamination is detected, the affected water will be pumped to a purge water holding tank and then pumped down one of the injection wells.

Piping

Piping from the blowdown sump dilution connection point is routed to the deep injection wells and distributed in two branches; one branch is oriented in a north-

south direction and located to the east of Unit 6. The second branch is oriented in the east-west direction and located to the south of Units 6 & 7.

The injectate piping connecting the pump station to the deep injection wells consists of a main line from the pump station that passes near each injection well and injectate feeder lines that connect the main line to each deep injection well. The piping is constructed of steel. The pipe diameter closest to the blowdown sump is approximately 60 inches in diameter and the pipe diameter at the last well in a branch is approximately 24 inches in diameter.

Valves

There are multiple valves on each deep injection well. This valving consists of an 18-inch-diameter gate valve located on the wellhead approximately 3 feet above where the injection well exits the ground, and an 18-inch-diameter butterfly valve located on the horizontal run of surface pipe on the concrete well pad. Air/vacuum release valves are provided at the appropriate location on each branch of the blowdown sump discharge piping.

The air/vacuum release valves are designed for the specific application and the level of service expected during operation. The injection lines on the operating wells remain full of water during operation, minimizing the number of times the valves are required to change position. Operating procedures provide the appropriate instructions to ensure actions are implemented correctly to limit or avoid pressure surges in the system. The valves are included in the preventive maintenance program to ensure the valves are checked periodically and maintained within acceptable parameters.

Redundant isolation valves are installed on the injectate main line to allow isolation of the main line in case of damage or failure to this line. Each injectate feeder line is equipped with redundant isolation valves where the injectate feeder lines connect to the main line to allow for the isolation of each individual injectate feeder line. Electronic remotely operated valves will isolate deep injection wells.

Vent valves are installed at required locations on each branch line. Vent valves are included to remove air either coming out of solution or air introduced by the air/vacuum release valves in the event that air is not swept out of the line during system startup. During normal operation, the vent lines are capped and the vent valves locked closed to prevent inadvertent operation. The vents are manually operated as needed for pump startup.

9.2.12.3 System Operation

The DIS operates during normal modes of operation, including startup, power operation, cooldown, shutdown, and refueling.

Dilution water is available during all modes of plant operation to maintain a minimum 6000 gpm dilution rate for each unit discharging liquid radwaste. The DIS is designed to accommodate the blowdown sump discharge flow rates for either source of CWS makeup water—reclaimed water or saltwater. The blowdown flow rate is determined by the number of deep injection wells used.

9.2.12.4 Safety Evaluation

The DIS has no safety-related function and therefore requires no nuclear safety evaluation.

The deep well injection system is the flow path for liquid radwaste discharges. Valving is provided to prevent or minimize the potential for radioactive fluid release to the environment due to damage to the above grade piping or operational issues with the deep injection wells. Section 11.2 describes the potential releases to the environment and includes the evaluation of these postulated releases.

9.2.12.5 Tests and Inspections

Initial test requirements for the DIS are described in Subsection 14.2.9.4.28.

System performance and structural and pressure integrity of system components is demonstrated by operation of the system, monitoring of system parameters such as flow and pressure, and visual inspections.

9.2.12.6 Instrumentation Applications

Continuous injection rate and injection pressure monitoring is performed at each deep injection well in service. Continuous monitoring of the water level of both monitor zones of the dual zone monitor wells is also performed. The data is transmitted to each control room where it is continuously monitored.

Radiological and chemical monitoring is also performed at each operational deep injection well and dual zone monitor well to assess system performance and to monitor confinement in the subsurface. Sections 11.2 and 11.5 describe the radiation monitoring controls governing the discharge to the deep well injection system.

STD DEP 1.1-1

9.2.13 COMBINED LICENSE INFORMATION

9.2.13.1 Potable Water

PTN COL 9.2-1

This COL item is addressed in Subsections 9.2.5.2.1 and 9.2.5.3.

9.2.13.2 Wastewater Retention Basins

PTN COL 9.2-2

This COL item is addressed in Subsections 9.2.9.2.2 and 9.2.9.5.

STD DEP 1.1-1

9.2.14 REFERENCES

PTN DEP 2.0-2

Table 9.2.7-1R
COMPONENT DATA — CENTRAL CHILLED WATER SYSTEM

High Capacity Subsystem	
Water Cooled Chillers	
Capacity (nominal tons)	1700
Compressor type	Centrifugal
Maximum power input (kW)	1700
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Cooling water flowrate (gpm)	3500 (max)
Air-Cooled Chillers	
Capacity (nominal tons)	~~300~~ 400
Compressor type	Reciprocating, Screw
Maximum power input (kW)	~~375~~ 500
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Low Capacity Subsystem	
Air-Cooled Chillers	
Capacity (nominal tons)	300
Compressor type	Reciprocating, Screw
Maximum power input (kW)	375
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Coil	**Flow (gpm)**
VBS MY C01 A/B	138
VBS MY C02 A/C	108
VBS MY C02 B/D	84
VAS MY C07 A/B	24
VAS MY C12 A/B	15
VAS MY C06 A/B	15

Figure 9.2-201 Raw Water System Flow Diagram (Sheet 1 of 3)

PTN SUP 9.2-2

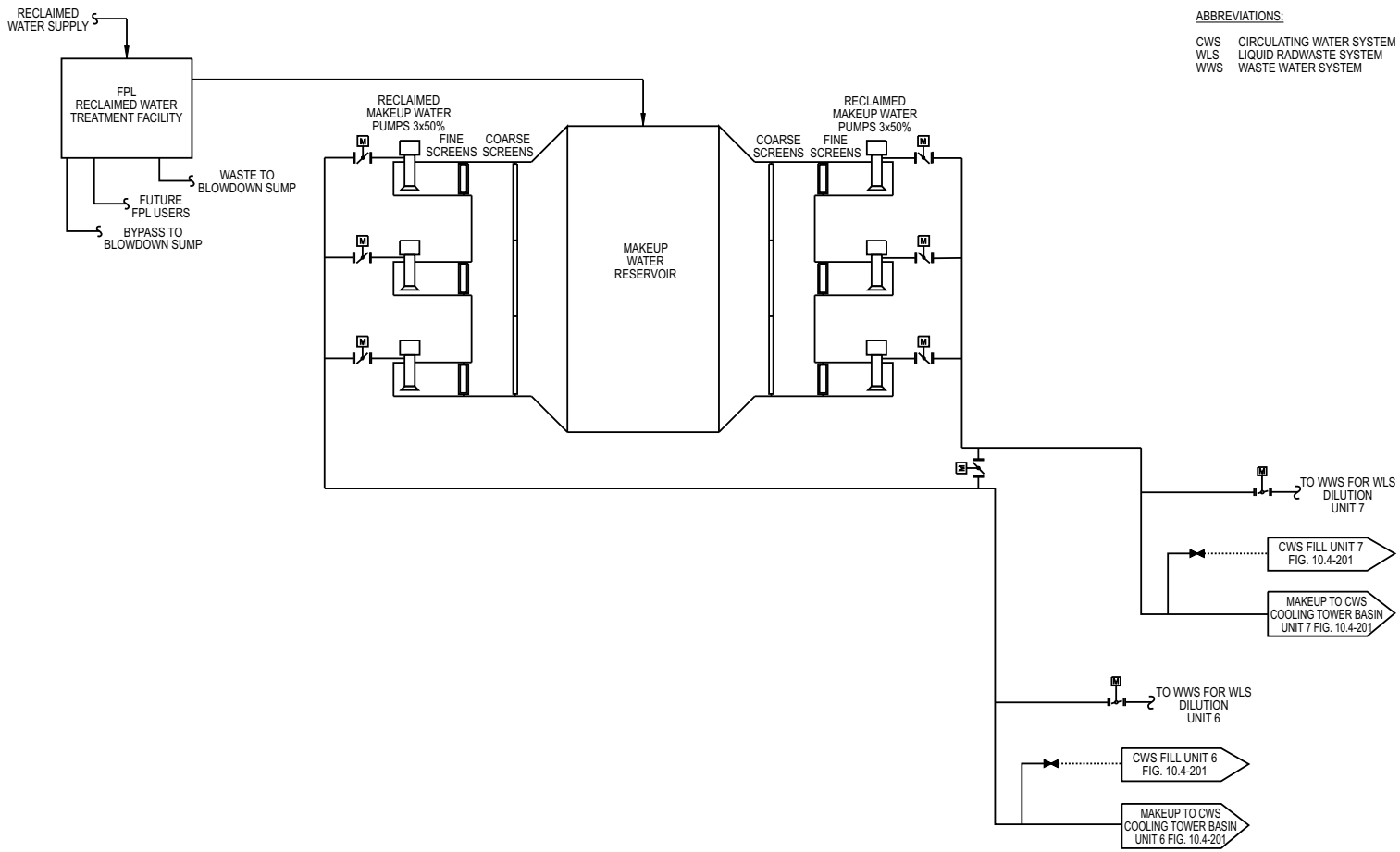


Figure 9.2-201 Raw Water System Flow Diagram (Sheet 2 of 3)

PTN SUP 9.2-2

ABBREVIATIONS:

CWS CIRCULATING WATER SYSTEM
WLS LIQUID RADWASTE SYSTEM
WWS WASTE WATER SYSTEM

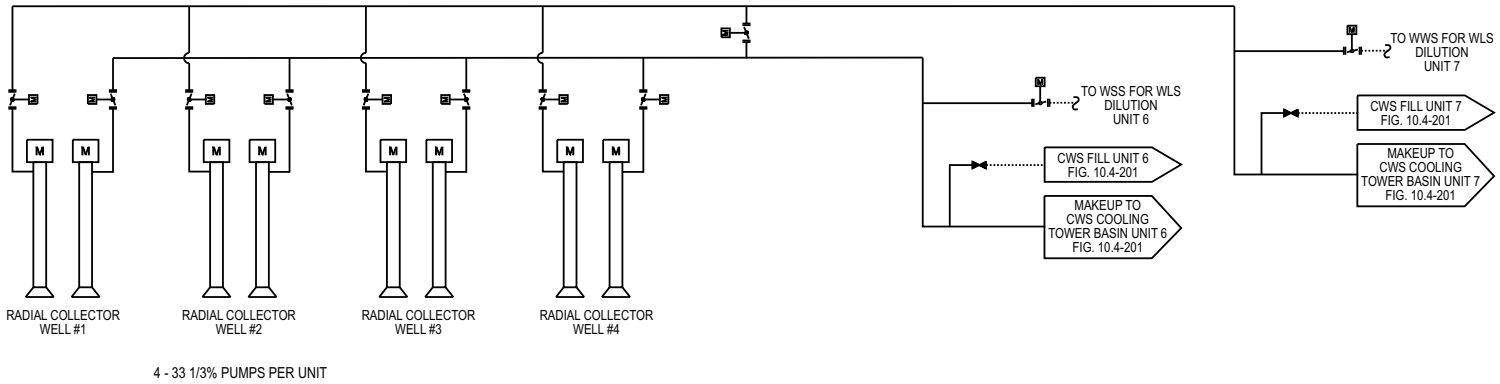


Figure 9.2-201 Raw Water System Flow Diagram (Sheet 3 of 3)

PTN SUP 9.2-2

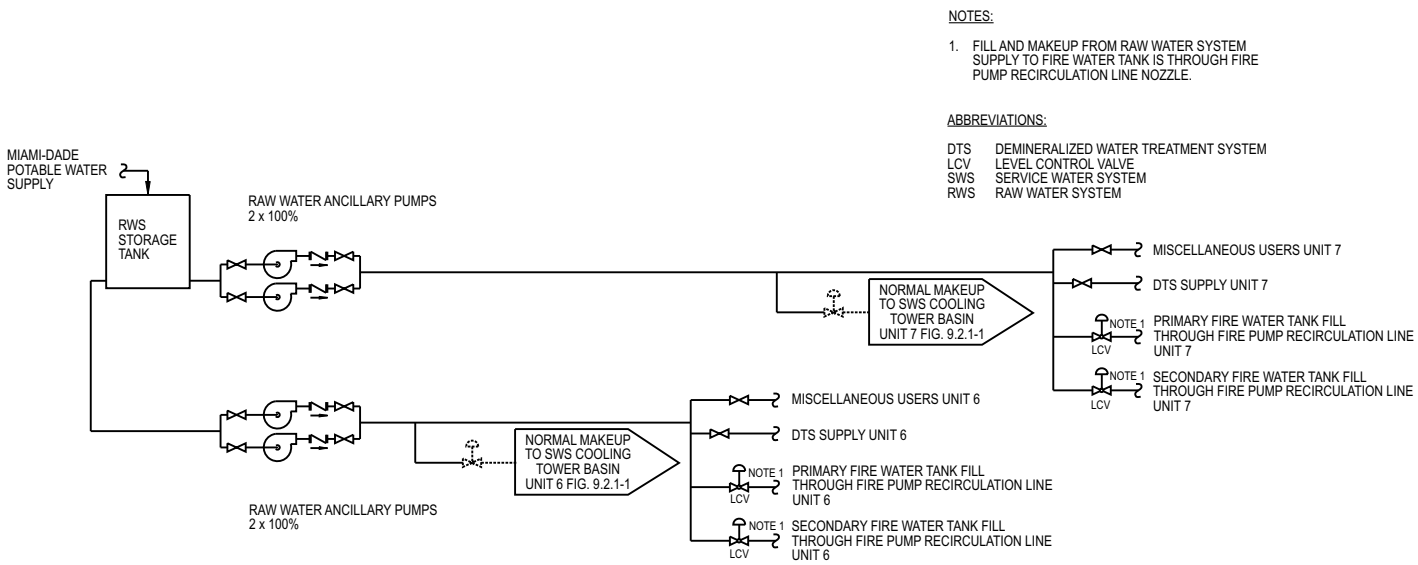


Figure 9.2-202 Deep Well Injection and Dual Zone Monitoring Well Locations

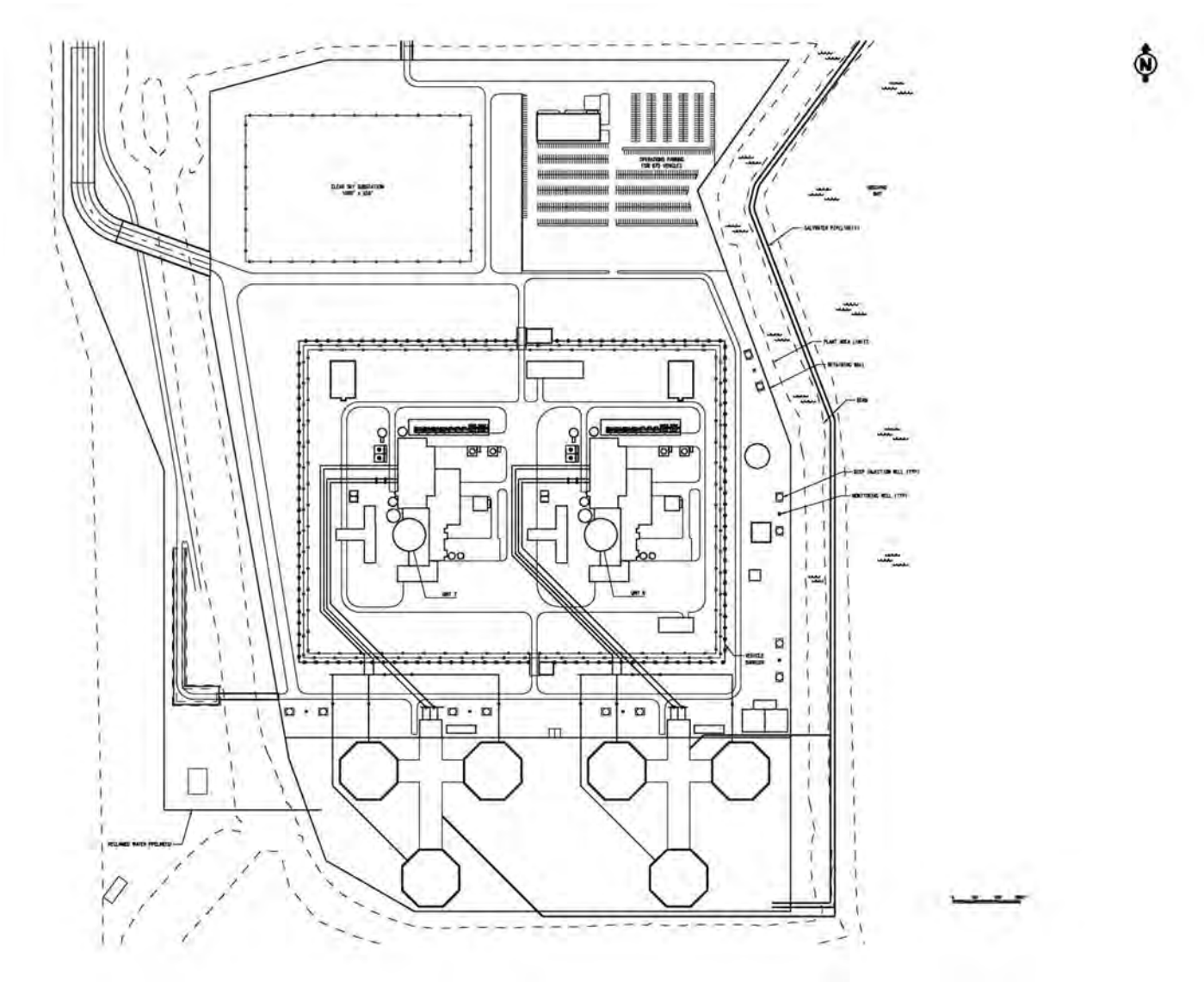


Figure 9.2-203 Liquid Waste Stream Collection and Disposal Schematic (Typical)

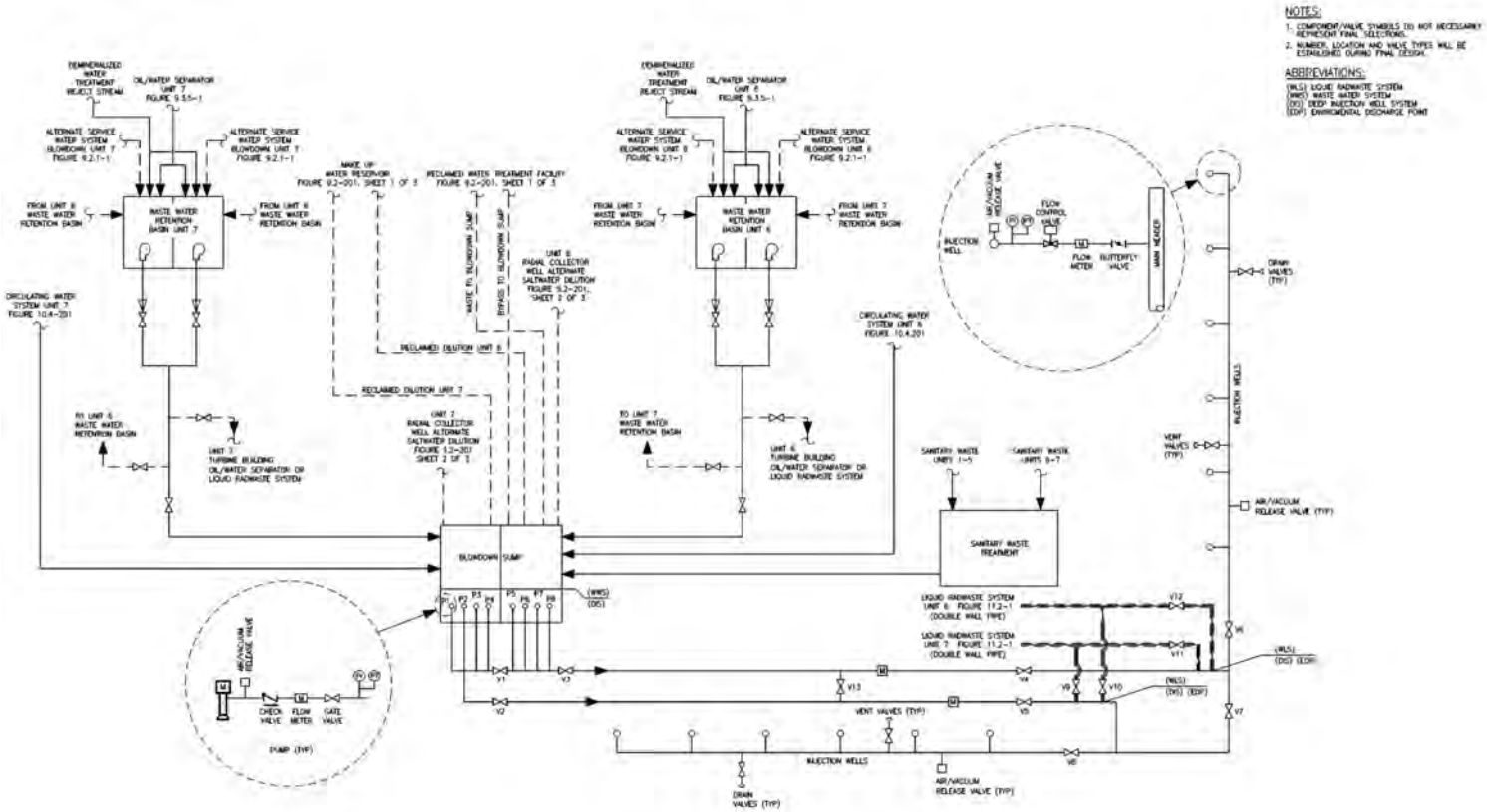


Figure 9.2-204 Deep Injection Well (Typical)

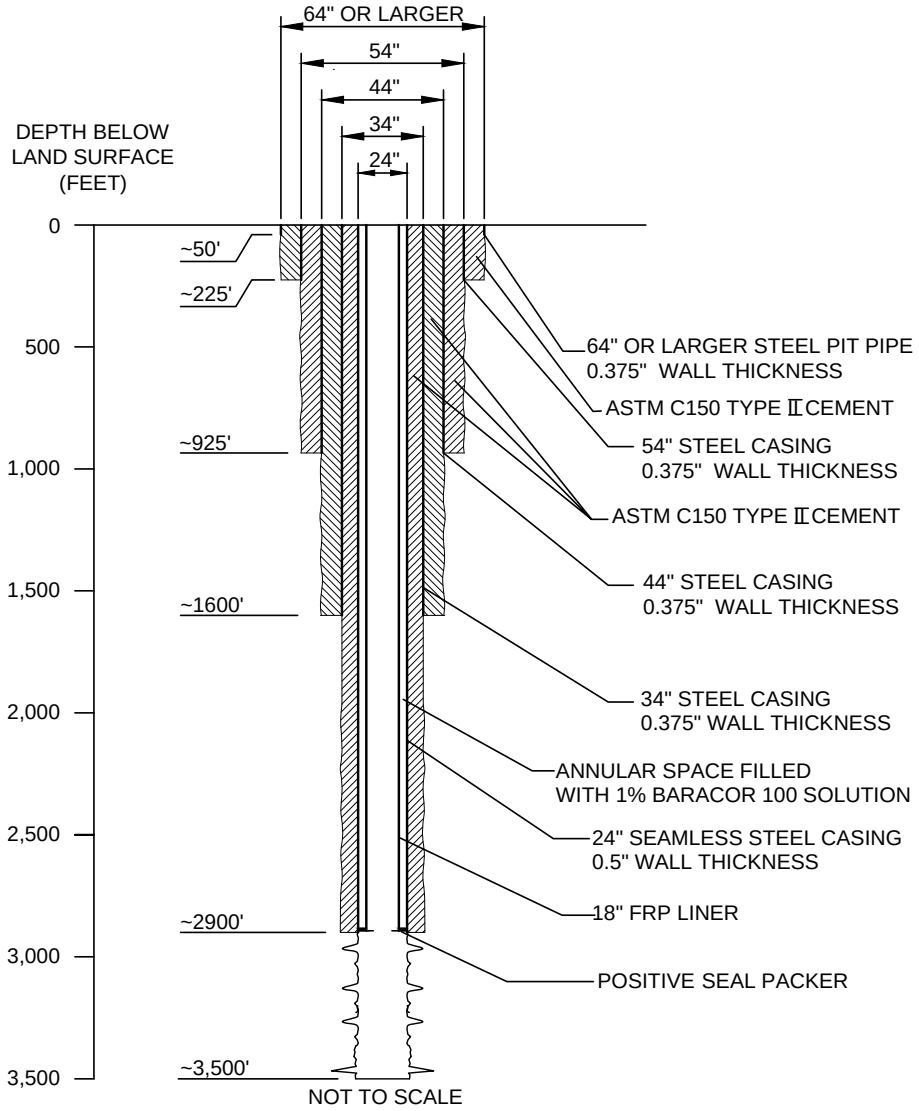
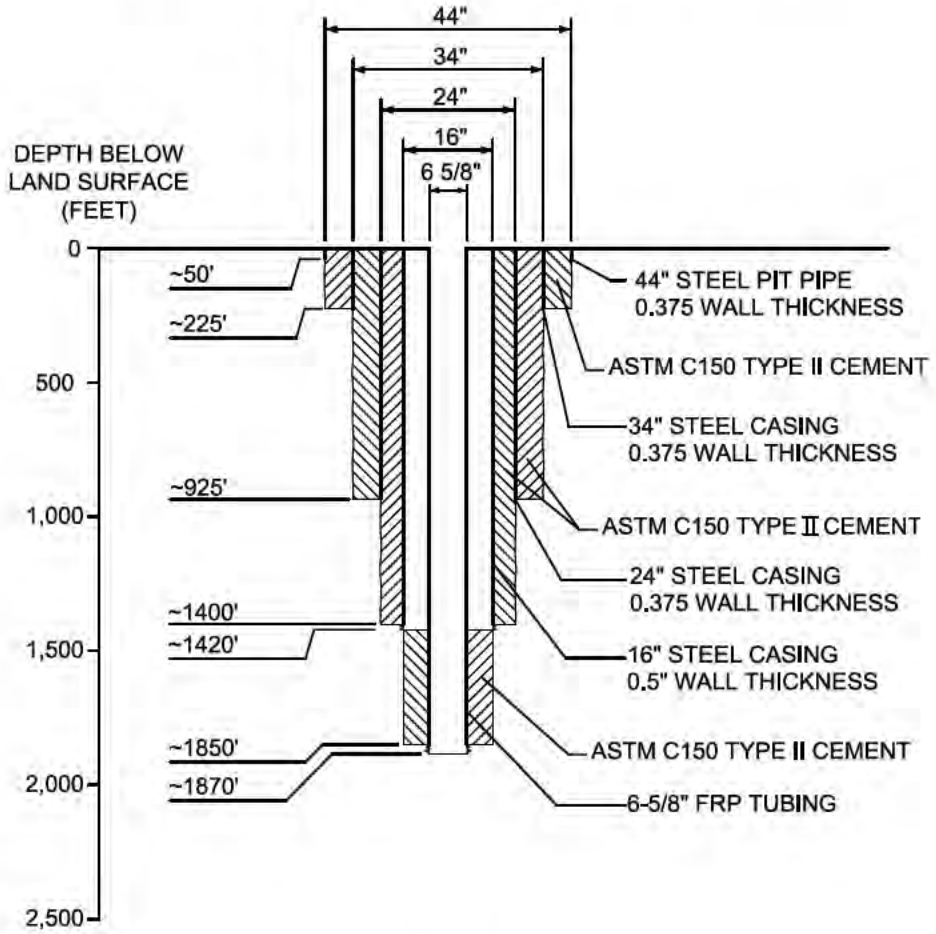


Figure 9.2-205 Dual Zone Monitoring Well (Typical)



NOT TO SCALE

9.3 PROCESS AUXILIARIES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9.3.1.1.2 Power Generation Design Basis

Change the third paragraph in DCD Subsection 9.3.1.1.2, as follows:

PTN DEP 6.4-2

The high-pressure air subsystem consists of one compressor, its associated air purification system and controls, and a high-pressure receiver. It provides clean, oil-free, high-pressure air to recharge the main control room emergency habitability system cylinders, refill the individual fire fighting breathing air bottles, and recharge the generator breaker reservoir. Quality Verification Level E air as defined in ANSI/CGA G-7.1, with a pressure dew point of 40°F or lower at 3400 psig or greater, is produced by this subsystem. See Section 6.4 for a description of the main control room habitability system.

9.3.6.3.7 Chemical and Volume Control System Valves

Revise the paragraph under the subheading Demineralized Water System Isolation Valves as follows:

Demineralized Water System Isolation Valves

These normally open, air-operated butterfly valves are located outside containment in the line from the demineralized water storage and transfer system. These valves close on a signal from the protection and safety monitoring system derived by either a reactor trip signal, a source range flux doubling signal, low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers, or a safety injection signal, isolating the demineralized water source to prevent inadvertent boron dilution events and, during shutdown conditions, whenever the flux doubling signal is blocked to prevent inadvertent boron dilution. Manual control for these valves is provided from the main control room and at the remote shutdown workstation.

PTN DEP 7.3-1

9.3.6.4.5.1 Boron Dilution Events

Add the following at the end of the third paragraph of DCD Subsection 9.3.6.4.5.1:

PTN DEP 7.3-1

In addition, when the flux doubling signal is blocked during shutdown, the demineralized water system isolation valves are closed to prevent inadvertent boron dilution.

9.3.6.7 Instrumentation Requirements

Revise the fourth bullet following the third paragraph of DCD Subsection 9.3.6.7 as follows:

PTN DEP 7.3-1

- **Demineralized water system isolation valves** — To prevent inadvertent boron dilution, the demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, low input voltage (loss of ac power) to the 1E dc and uninterruptible power supply system battery chargers, or a safety injection signal providing a safety-related method of stopping an inadvertent dilution. In addition, when the flux doubling logic is blocked during shutdown, the valves are closed to prevent inadvertent boron dilution. The main control room and remote shutdown workstation provide manual control for these valves.

9.3.7 COMBINED LICENSE INFORMATION

STD COL 9.3-1

This COL Item is addressed below.

Generic Issue 43, and the concerns of Generic Letter 88-14 and NUREG-1275 regarding degradation or malfunction of instrument air supply and safety-related

valve failure, are addressed by the training and procedures for operations and maintenance of the instrument air subsystem and air-operated valves.

Plant systems, including the compressed and instrument air system, are maintained in accordance with procedures. Maintenance procedures are discussed in Subsection 13.5.2.2.6. The instrument air supply subsystem components are maintained and tested in accordance with manufacturers' recommendations and procedures. The safety-related air-operated valves are maintained in accordance with manufacturers' recommendations and tested in accordance with plant procedures to allow proper function on loss of air. The instrument air is periodically sampled and tested for compliance with the quality requirements of ANSI/ISA-S7.3-1981.

Operators are provided training on loss of instrument air in accordance with abnormal operating procedures. Plant systems, including the compressed and instrument air system, are operated in accordance with system operating procedures, abnormal operating procedures, and alarm response procedures which are written in accordance with Subsection 13.5.2. The training program for operations and maintenance personnel is discussed in Section 13.2.

9.4 AIR-CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9.4.1.1.1 Safety Design Basis

Revise the second bullet in the first paragraph of DCD Subsection 9.4.1.1.1 to read as follows:

PTN DEP 6.4-1

- Isolates the HVAC penetrations in the main control room boundary on High-2 particulate or iodine concentrations in the main control room supply air or on extended loss of ac power to support operation of the main control room emergency habitability system as described in Section 6.4.

9.4.1.1.2 Power Generation Design Basis

Revise the third bullet in the first paragraph of DCD Subsection 9.4.1.1.2 to read as follows:

PTN DEP 6.4-1

- Isolates the main control room and/or CSA area from the normal outdoor air intake and provides filtered outdoor air to pressurize the main control room and CSA areas to a positive pressure of at least 1/8 inch wg when a High-1 radioactivity concentration (gaseous, particulate, or iodine) is detected in the main control room supply air duct.

Post-72-Hour Design Basis

Main Control Room

Revise the first paragraph of DCD Subsection 9.4.1.1.2, under the sub-heading, Post-72-Hour Design Basis Main Control Room to read:

PTN DEP 6.4-2

The specific function of the nuclear island nonradioactive ventilation system is to maintain the main control room below a maximum average Wet Bulb Globe Temperature index of 90°F (32.2°C) based on operation at the maximum normal site ambient temperature.

9.4.1.2.1.1 Main Control Room/Control Support Area HVAC Subsystem

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Revise the second to last sentence of the second paragraph of DCD Subsection 9.4.1.2.1.1 to read as follows:

PTN DEP 6.4-1

These monitors initiate operation of the nonsafety-related supplemental air filtration units on High-1 radioactivity concentrations (gaseous, particulate, or iodine) and isolate the main control room from the nuclear island nonradioactive ventilation system on High-2 particulate or iodine radioactivity concentrations.

9.4.1.2.3.1 Main Control Room/Control Support Area HVAC Subsystem

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Revise the second and third sentences of the first paragraph of the Abnormal Plant Operation section of DCD Subsection 9.4.1.2.3.1 to read as follows:

PTN DEP 6.4-1

The first is “High-1” radioactivity based upon radioactivity instrumentation (gaseous, particulate, or iodine). The second is “High-2” radioactivity based upon either particulate or iodine radioactivity instruments.

Revise the first sentence of the second paragraph of the Abnormal Plant Operation section of DCD Subsection 9.4.1.2.3.1 to read as follows:

PTN DEP 6.4-1

If “High-1” radioactivity is detected in the main control room supply air duct and the main control room/control support area HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the main control room and CSA areas to at least 1/8 inch wg with respect to the surrounding areas and the outside environment using filtered makeup air.

Revise the first sentence of the third paragraph of the Abnormal Plant Operation section of DCD Subsection 9.4.1.2.3.1 to read as follows:

PTN DEP 6.4-1

If ac power is unavailable for more than 10 minutes or if "High-2" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding GDC-19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room from the normal main control room/control support area HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves.

Abnormal Plant Operation

Revise the eighth paragraph of DCD Subsection 9.4.1.2.3.1, Abnormal Plant Operation to read:

PTN DEP 6.4-2

When complete ac power is lost and the outside air is acceptable radiologically and chemically, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR. It is expected that outside air will be acceptable within 72 hours following a radiological release. See Subsection 6.4.2.2 for details. The outside air pathway to the ancillary fans is provided through the nonradioactive ventilation system air intake opening located on the roof, the mechanical room at floor elevation 135'-3", and nonradioactive ventilation system supply duct. Warm air from the MCR is vented to the annex building through stairway S05, into the remote shutdown room and the clean access corridor at elevation 100'-0". The ancillary fan capacity and air flow rate maintain the MCR environment below a maximum average Wet Bulb Globe Temperature index of 90°F (32.2°C). The ancillary fans and flow path are located within the auxiliary building which is a Seismic Category I structure.

9.4.1.4 Tests and Inspection

Add the following text at the end of DCD Subsection 9.4.1.4.

STD COL 9.4-1a

The main control room/control support area HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS) is tested and inspected in accordance with ASME/ANSI AG-1-1997 and Addenda AG-1a-2000 (Reference 201), ASME N509-1989, ASME N510-1989, and Regulatory Guide 1.140.

The VBS is tested as separate components and as an integrated system. Surveillance tests are performed to monitor the condition of the system. Testing methods include:

- Visual inspection
- Duct and housing leak tests
- Airflow capacity and distribution tests
- Air-aerosol mixing uniformity test
- HEPA filter bank and adsorber bank in-place leak tests
- Duct damper bypass tests
- System bypass tests
- Air heater performance tests
- Laboratory testing of adsorbers
- Ductwork inleakage test

Testing is performed at the frequency provided in Table 1 of ASME N510-1989.

9.4.2.2 System Description

Replace the second sentence of the first paragraph of DCD Subsection 9.4.2.2.1.1 with the following sentence.

PTN DEP 18.8-1

These areas include the men's and women's change and toilet rooms, the ALARA briefing room, offices, corridors, men's and women's rest rooms, conference rooms, and office areas.

9.4.7.4 Tests and Inspections

Add the following text at the end of DCD Subsection 9.4.7.4.

STD COL 9.4-1a

The exhaust subsystem of the containment air filtration system (VFS) is tested and inspected in accordance with ASME/ANSI AG-1-1997 and Addenda AG-1a-2000 (Reference 201), ASME N509-1989, ASME N510-1989, and Regulatory Guide 1.140.

The VFS is tested as separate components and as an integrated system. Surveillance tests are performed to monitor the condition of the system. Testing methods include:

- Visual inspection
- Airflow capacity and distribution tests
- HEPA filter bank and adsorber bank in-place leak tests
- System bypass tests
- Air heater performance tests
- Laboratory testing of adsorbers
- Ductwork inleakage test

Testing is performed at the frequency provided in Table 1 of ASME N510-1989.

9.4.12 COMBINED LICENSE INFORMATION

STD COL 9.4-1a

This COL Item is addressed in Subsections 9.4.1.4 and 9.4.7.4.

PTN COL 9.4-1b

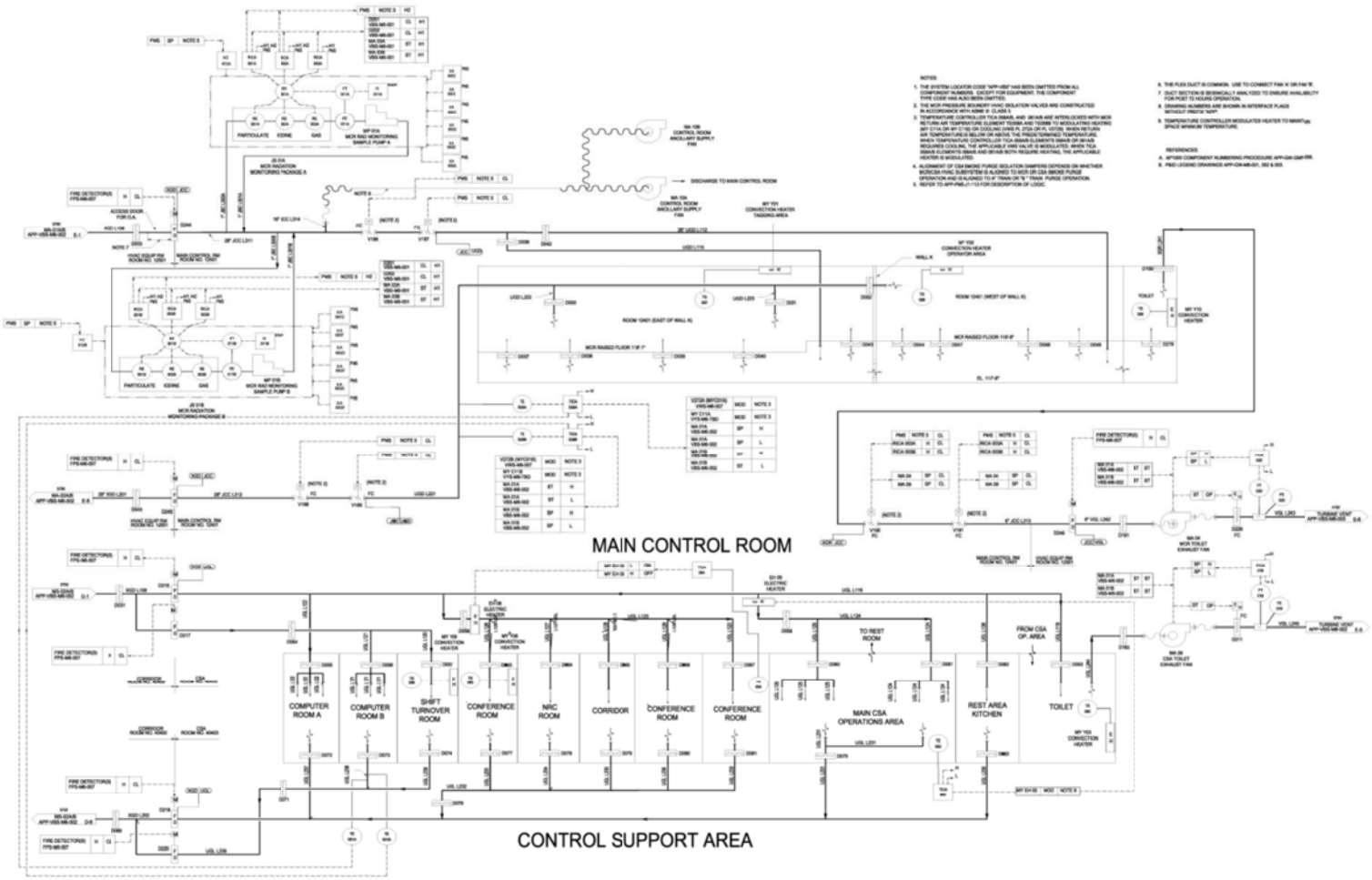
Section 6.4 does not identify any toxic emergencies that require the main control room/control support area HVAC to enter recirculation mode.

9.4.13 REFERENCES

201. American Society of Mechanical Engineers/American National Standards Institute, *Code on Nuclear Air and Gas Treatment*, Section HA, Housings, ASME/ANSI AG-1a-2000, Addenda to ASME AG-1-1997.

PTN DEP 6.4-1

Figure 9.4.1-1R Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram



9.5 OTHER AUXILIARY SYSTEMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9.5.1.2.1.3 Fire Water Supply System

STD SUP 9.5-1 Add the following paragraphs at the end of DCD Subsection 9.5.1.2.1.3.

Threads compatible with those used by the off-site fire department are provided on all hydrants, hose couplings and standpipe risers, or a sufficient number of thread adapters compatible with the off-site fire department are provided.

9.5.1.6 Personnel Qualification and Training

STD COL 9.5-1 Add the following paragraph at the end of DCD Subsection 9.5.1.6.

Subsections 9.5.1.8.2 and 9.5.1.8.7 summarize the qualification and training programs that are established and implemented for the Fire Protection Program.

STD DEP 1.1-1 Insert the following subsections after DCD Subsection 9.5.1.7. DCD Subsection 9.5.1.8 is renumbered as Subsection 9.5.1.9.

9.5.1.8 Fire Protection Program

STD COL 9.5-1 The fire protection program is established such that a fire does not prevent safe shutdown of the plant and does not endanger the health and safety of the public. Fire protection at the plant uses a defense-in-depth concept that includes fire prevention, detection, control and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. These defense-in-depth principles are achieved by meeting the following objectives:

- Prevent fires from starting.
- Detect rapidly, control, and extinguish promptly those fires that do occur.
- Provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities does not prevent the safe shutdown of the plant.
- Minimize the potential for radiological releases.

9.5.1.8.1 Fire Protection Program Implementation

As indicated in Table 13.4-201, the required elements of the fire protection program are fully operational prior to receipt of new fuel for buildings storing new fuel and adjacent fire areas that could affect the fuel storage area in that reactor unit. Other required elements of the fire protection program described in this section are fully operational prior to initial fuel loading in that reactor unit.

Elements of the fire protection program are reviewed on a frequency established by procedures and updated as necessary.

9.5.1.8.1.1 Fire Protection Program Criteria

STD COL 9.5-4
STD COL 9.5-3

The fire protection program is based on the criteria of several industry and regulatory documents referenced in FSAR Subsection 9.5.5 and DCD Subsection 9.5.5, and also based on the guidance provided in Regulatory Guide 1.189. DCD Tables 9.5.1-1 and FSAR Table 9.5-201 provide a cross-reference to information addressing compliance with BTP CMEB 9.5-1. Exceptions to the National Fire Protection Association (NFPA) Standards beyond those included in DCD Table 9.5.1-3, and exceptions taken to the NFPA Standards listed in FSAR Subsection 9.5.5, are identified in FSAR Table 9.5-202.

9.5.1.8.1.2 Organization and Responsibilities

STD COL 9.5-1

The organizational structure of the fire protection personnel is discussed in Subsection 13.1.1.2.10.

The site executive in charge of the fire protection program, through the engineer in charge of fire protection, is responsible for the following:

a. Programs and periodic inspections are implemented to:

1. Minimize the amount of combustibles in safety-related areas.

2. Determine the effectiveness of housekeeping practices.

3. Provide for availability and acceptability of the following:

i. Fire protection system and components.

ii. Manual fire fighting equipment.

iii. Emergency breathing apparatus.

iv. Emergency lighting.

v. Portable communication equipment.

STD COL 9.5-8
STD COL 9.5-1

vi. Fire barriers including fire rated walls, floors and ceilings, fire rated doors, dampers, etc., fire stops and wraps, and fire retardant coating. Procedures address the administrative controls in place, including fire watches, when a fire area is breached for maintenance.

STD COL 9.5-1

b. Confirm prompt and effective corrective actions are taken to correct conditions adverse to fire protection and preclude their recurrence.

c. Conducting periodic maintenance and testing of fire protection systems, components, and manual fire fighting equipment, evaluating test results, and determining the acceptability of systems under test in accordance with established plant procedures.

d. Designing and selecting equipment related to fire protection.

e. Reviewing and evaluating proposed work activities to identify potential transient fire loads.

f. Managing the plant fire brigade, including:

   1. Developing, implementing and administering the fire brigade training program.

   2. Scheduling and conducting fire brigade drills.

   3. Critiquing fire drills to determine if training objectives are met.

   4. Performing a periodic review of the fire brigade roster and initiating changes as needed.

   5. Maintaining the fire training program records for members of the fire brigade and other personnel.

   6. Maintaining a sufficient number of qualified fire brigade personnel to respond to fire emergencies for each shift.

g. Developing and conducting the fire extinguisher training program.

h. Implementing a program for indoctrination of personnel gaining unescorted access to the protected area in appropriate procedures which implement the fire protection program, such as fire prevention and fire reporting procedures, plant emergency alarms, including evacuation.

i. Implementing a program for instruction of personnel on the proper handling of accidental events such as leaks or spills of flammable materials.

j. Preparing procedures to meet possible fire situations in the plant and for assuring assistance is available for fighting fires in radiological areas.

k. Implementing a program that utilizes a permit system that controls and documents inoperability of fire protection systems and equipment. This program initiates proper notifications and

compensatory actions, such as fire watches, when inoperability of any fire protection system or component is identified.

l. Developing and implementing preventive maintenance, corrective maintenance, and surveillance test fire protection procedures.

m. Confirming that plant modifications, new procedures and revisions to procedures associated with fire protection equipment and systems that have significant impact on the fire protection program are reviewed by an individual who possesses the qualifications of a fire protection engineer.

n. Continuing evaluation of fire hazards during construction or modification of other units on the site. Special considerations, such as fire barriers, fire protection capability and administrative controls are provided as necessary to protect the operating unit(s) from construction or modification activities.

o. Establishing a fire prevention surveillance plan and training plant personnel on that plan.

p. Developing pre-fire plans and making them available to the fire brigade and control room.

PTN COL 9.5-1 The responsibilities of the engineer in charge of fire protection and his staff are described in Subsection 13.1.2.1.3.9.

STD COL 9.5-1

9.5.1.8.2 Fire Brigade

9.5.1.8.2.1 General

PTN COL 9.5-1 The organization of the fire brigade is described in Subsection 13.1.2.1.6.

STD COL 9.5-1 To qualify as a member of the fire brigade, an individual must meet the following criteria:

a. Has attended the required training sessions for the position occupied on the fire brigade.

b. Has passed an annual physical exam including demonstrating the ability for performing strenuous activity and the use of respiratory protection.

9.5.1.8.2.2 Fire Brigade Training

A training program is established so that the capability to fight fires is developed and documented. The program consists of classroom instruction supplemented with periodic classroom retraining, practice in fire fighting, and fire drills. Classroom instruction and training is conducted by qualified individuals knowledgeable in fighting the types of fires that could occur within the plant and its environs and using on-site fire fighting equipment. Individual records of training provided to each fire brigade member, including drill critiques, are maintained as part of the permanent plant files for at least three years to document that each member receives the required training.

The fire brigade leader and at least two brigade members per shift have sufficient training and knowledge of plant safety-related systems to understand the effects of fire and fire suppressants on safe shutdown capability. The brigade leader is competent to assess the potential safety consequences of a fire and advise control room personnel. Such competence by the brigade leader may be evidenced by possession of an operator's license or equivalent knowledge of plant systems.

Personnel assigned as fire brigade members receive formal training prior to assuming brigade duties. The course subject matter is selected to satisfy the requirements of Regulatory Guide 1.189. Course material selection also includes guidance from NFPA 600 (Reference 204) and 1500 (Reference 210) as appropriate. Additional training may also include material selected from NFPA 1404 (Reference 208) and 1410 (Reference 209).

The minimum equipment provided for the fire brigade consists of personal protective equipment such as turnout coats, boots, gloves, hard hats, emergency communications equipment, portable lights, portable ventilation equipment and portable extinguishers. Self-contained breathing apparatus (SCBA) approved by NIOSH, using full face positive pressure masks, and providing an operating life of at least 30 minutes, are provided for selected fire brigade, emergency repair and control room personnel. At least ten masks are provided for fire brigade personnel. At least two extra air bottles, each with at least 30 minutes of operating

life, are located on site for each SCBA. An additional on-site 6-hour supply of reserve air is provided to permit quick and complete replenishment of exhausted supply air bottles. DCD Subsection 6.4.2.3 discusses the portable breathing apparatus for control room personnel. Additional SCBAs are provided near the personnel containment entrance for the exclusive use of the fire brigade. The fire brigade leader has ready access to keys for any locked fire doors.

The on-duty shift manager has responsibility for taking certain actions based on an assessment of the magnitude of the fire emergency. These actions include safely shutting down the plant, making recommendations for implementing the Emergency Plan, notification of emergency personnel and requesting assistance from off-duty personnel, if necessary. Emergency Plan consideration of fire emergencies includes the guidance of Regulatory Guide 1.101.

9.5.1.8.2.2.1 Classroom Instruction

Fire brigade members receive classroom instruction in fire protection and fire fighting techniques prior to qualifying as members of the fire brigade. This instruction includes:

a. Identification of the types of fire hazards along with their location within the plant and its environs.

b. Identification of the types of fires that could occur within the plant and its environs.

c. Identification of the location of on-site fire fighting equipment and familiarization with the layout of the plant including ingress and egress routes to each area.

d. The proper use of on-site fire fighting equipment and the correct method of fighting various types of fires including at least the following:

   — fires involving radioactive materials

   — fires in energized electrical equipment

   — fires in cables and cable trays

   — fires involving hydrogen

— fires involving flammable and combustible liquids or hazardous process chemicals

— fires resulting from construction or modifications (welding)

— fires involving record files.

e. Review of each individual’s responsibilities under the Fire Protection Program.

f. Proper use of communication, lighting, ventilation, and emergency breathing equipment.

g. Fire brigade leader direction and coordination of fire fighting activities.

h. Toxic and radiological characteristics of expected combustion products.

i. Proper methods of fighting fires inside buildings and confined spaces.

j. Detailed review of fire fighting strategies, procedures and procedure changes.

k. Indoctrination of the plant fire fighting plans, identification of each individual's responsibilities, and review of changes in the fire fighting plans resulting from fire protection-related plant modifications.

l. Coordination between the fire brigade and off-site fire departments that have agreed to assist during a major fire on-site is provided to establish responsibilities and duties. Educating the off-site organization in operational precautions when fighting fires on nuclear power plant sites, and awareness of special hazards and the need of radiological protection of personnel.

9.5.1.8.2.2.2 Retraining

Classroom refresher training is scheduled on a biennial basis to supplement retention of the initial training. These sessions may be concurrent with the regular planned meetings.

9.5.1.8.2.2.3 Practice

Practice sessions are held for each fire brigade and for each fire brigade member on the proper method of fighting various types of fires which might occur in the

plant. These sessions are scheduled on an annual basis and provide brigade members with team experience in actual fire fighting and the use of emergency breathing apparatus under strenuous conditions encountered in fire fighting.

9.5.1.8.2.2.4 Drills

Fire brigade drills are conducted at least once per calendar quarter for each shift. Each fire brigade member participates in at least two drills annually. Drills are either announced or unannounced. At least one unannounced drill is held annually for each shift fire brigade. At least one drill is performed annually on a “back shift” for each shift’s fire brigade. The drills provide for off-site fire department participation at least annually. Triennially, a randomly selected, unannounced drill shall be conducted and critiqued by qualified individuals independent of the plant staff. Training objectives are established prior to each drill and reviewed by plant management. Drills are critiqued on the following points:

a. Assessment of fire alarm effectiveness.

b. Assessment of time required to notify and assemble the fire brigade.

c. Assessment of the selection, placement and use of equipment.

d. Assessment of the fire brigade leader’s effectiveness in directing the fire fighting effort.

e. Assessment of each fire brigade member’s knowledge of fire fighting strategy, procedures and simulated use of equipment.

f. Assessment of the fire brigade’s performance as a team.

Performance deficiencies identified, based on these assessments, are used as the basis for additional training and repeat drills. Unsatisfactory drill performance is followed by a repeat drill within 30 days.

9.5.1.8.2.2.5 Meetings

Regular planned meetings are held at least quarterly for the fire brigade members to review changes in the Fire Protection Program and other subjects as necessary.

9.5.1.8.3 Administrative Controls

Administrative controls for the Fire Protection Program are implemented through plant administrative procedures. Applicable industry publications are used as guidance in developing those procedures.

Administrative controls include procedures to:

a. Control actions to be taken by an individual discovering a fire, such as notification of the control room, attempting to extinguish the fire, and actuation of local fire suppression systems.

b. Control actions to be taken by the control room operator, such as sounding fire alarms, and notifying the shift manager of the type, size and location of the fire.

c. Control actions to be taken by the fire brigade after notification of a fire, including location to assemble, directions given by the fire brigade leader, the responsibilities of brigade members, such as selection of fire fighting and protective equipment, and use of preplanned strategies for fighting fires in specific areas.

d. Control actions to be taken by the security force upon notification of a fire.

e. Define the strategies established for fighting fires in safety-related areas and areas presenting a hazard to safety-related equipment, including the designation of the:

    1. Fire hazards in each plant area/zone covered by a fire fighting procedure (pre-fire plan). Pre-fire plans utilize the guidance of NFPA 1620 (Reference 205).

    2. Fire extinguishers best suited for controlling fires with the combustible loadings of each zone and the nearest location of these extinguishers.

    3. Most favorable direction from which to attack a fire in each area in view of the ventilation direction, access hallways, stairs, and doors that are most likely to be free of fire, and the best station or elevation for fighting the fire. Access and egress routes that involve locked doors are specifically identified in the procedure with the appropriate precautions and methods for access specified.

4. Plant systems that should be managed to reduce the damage potential during a local fire and the location of local and remote controls for such management (e.g., any hydraulic or electrical system in the zone covered by the specific fire fighting procedure that could increase the hazards in the area because of overpressurization or electrical hazards).

5. Vital heat-sensitive system components that need to be kept cool while fighting a local fire. Particularly hazardous combustibles that need cooling are designated.

6. Potential radiological and toxic hazards in fire zones.

7. Ventilation system operation that provides desired plant air distribution when the ventilation flow is modified for fire containment or smoke clearing operations.

8. Operations requiring control room and shift manager coordination or authorization.

9. Instructions for plant operators and other plant personnel during a fire.

f. Organize the fire brigade and assign special duties according to job title so that the fire fighting functions are covered for each shift by personnel trained and qualified to perform these functions. These duties include command control of the brigade, transporting fire suppression and support equipment to the fire scenes, applying the extinguishing agent to the fire, communication with the control room, and coordination with off-site fire departments.

9.5.1.8.4 Control of Combustible Materials, Hazardous Materials and Ignition Sources

The control of combustible materials is defined by administrative procedures. These procedures impose the following controls:

a. Prohibit the storage of combustible materials (including unused ion exchange resins) in areas that contain or expose safety-related equipment.

b. Govern the handling of and limit transient fire loads such as flammable liquids, wood and plastic materials in buildings containing safety-related systems or equipment.

c. Assign responsibility to the appropriate supervisor for reviewing work activities to identify transient fire loads.

d. Govern the use of ignition sources by use of a flame permit system to control welding, flame cutting, grinding, brazing and soldering operations, and temporary electrical power cables. A separate permit is issued for each area where such work is done. If work continues over more than one shift, the permit is valid for not more than 24 hours when the plant is operating or for the duration of a particular job during plant shutdown. NFPA 51B (Reference 202) and 241 (Reference 203) are used as guidance.

e. Minimize waste, debris, scrap, and oil spills or other combustibles resulting from a work activity in the safety-related area while work is in progress and remove the same upon completion of the activity or at the end of each work shift.

f. Govern periodic inspections for accumulation of combustibles for continued compliance with these administrative controls.

g. Prohibit the storage of acetylene-oxygen and other compressed gasses in areas that contain or expose safety-related equipment or the fire protection system that serves those areas. A permit system is required to control the use of this equipment in safety-related areas of the plant.

h. Govern the use and storage of hazardous chemicals in areas that contain or expose safety-related equipment.

i. Control the use of specific combustibles in safety-related areas. Wood used in safety-related areas during maintenance, modification, or refueling operation (such as lay-down blocks or scaffolding) is treated with a flame retardant in accordance with NFPA 703 (Reference 207). Use of wood inside buildings containing systems or equipment important to safety is only permitted when suitable noncombustible substitutes are not available. Equipment or supplies (such as new fuel) shipped in untreated combustible packing containers are unpacked in safety-related areas if required for valid operating reasons. However, combustible materials are

removed from the area immediately following unpacking. Such transient combustible material, unless stored in approved containers, is not left unattended during lunch breaks, shift changes, or other similar periods. Loose combustible packing material, such as wood or paper excelsior, or polyethylene sheeting, is placed in metal containers with tight-fitting self-closing metal covers. Only noncombustible panels or flame-retardant tarpaulins or approved materials of equivalent fire-retardant characteristics are used. Any other fabrics or plastic films used are certified to conform to the large-scale fire test described in NFPA 701 (Reference 206).

j. Govern the control of electrical appliances in areas that contain or expose safety-related equipment.

9.5.1.8.5 Control of Radioactive Materials

The plant is designed with provisions for sampling of liquids resulting from fire emergencies that may contain radioactivity and may be released to the environment. Plant operating procedures require such liquids to be collected, sampled, and analyzed prior to discharge. Liquid discharges are required to be below activity limits prior to discharge.

9.5.1.8.6 Testing and Inspection

Testing and inspection requirements are imposed through administrative procedures. Maintenance or modifications to the fire protection system are subject to inspection for conformation to design requirements. Procedures governing the inspection, testing, and maintenance of fire protection alarm and detection systems, and water-based suppression and supply systems, utilize the guidance of NFPA 72 (DCD Subsection 9.5.5, Reference 2) and NFPA 25 (Reference 212). Installation of portions of the system where performance cannot be verified through pre-operational tests, such as penetration seals, fire retardant coatings, cable routing, and fire barriers are inspected. Inspections are performed by individuals knowledgeable of fire protection design and installation requirements. Open flame or combustion-generated smoke is not used for leak testing or similar procedures such as air flow determination. Inspection and testing procedures address the identification of items to be tested or inspected, responsible organizations for the activity, acceptance criteria, documentation requirements and sign-off requirements.

Fire protection materials subject to degradation (such as fire stops, seals and fire retardant coatings are visually inspected periodically for degradation or damage.

Fire hoses are hydrostatically tested in accordance with NFPA 1962 (Reference 201). Hoses stored in outside hose stations are tested annually and interior standpipe hoses are tested every three years.

The fire protection system is periodically tested in accordance with plant procedures. Testing includes periodic operational tests and visual verification of damper and valve positions. Fire doors and their closing and latching mechanisms are also included in these procedures.

STD COL 9.5-6 The preoperational testing program describes the procedures for confirming that the as-installed configuration of fire barriers matches the tested configurations. The procedures describe the process for identifying and dispositioning deviations.

9.5.1.8.7 Personnel Qualification and Training

PTN COL 9.5-1 The engineer in charge of fire protection is responsible for the formulation and implementation of the fire protection program and meets the qualification requirements listed in FSAR Subsection 13.1.2.1.3.9.

STD COL 9.5-1 Qualification and training of other plant personnel involved in the fire protection program is governed by plant qualification procedures and is conducted by personnel qualified by training and experience in these areas. These classifications include training personnel, maintenance personnel assigned to work on the fire protection system, and operations personnel assigned to system operation and testing.

9.5.1.8.8 Fire Doors

STD COL 9.5-3 Fire doors separating safety-related areas are self-closing or provided with closing mechanisms and are inspected semiannually to verify that the automatic hold open, release and closing mechanisms and latches are operable. Watertight and missile resistant doors are not provided with closing mechanisms. Fire doors with automatic hold open and release mechanisms are inspected daily to verify that the doorways are free of obstructions.

Fire doors separating safety-related areas are normally closed and latched. Fire doors that are locked closed are inspected weekly to verify position. Fire doors that are closed and latched are inspected daily to assure that they are in the closed position. Fire doors that are closed and electrically supervised at a continuously manned location are not inspected.

9.5.1.8.9 Emergency Planning

Emergency planning is described in Section 13.3.

STD DEP 1.1-1

9.5.1.9 Combined License Information

9.5.1.9.1 Qualification Requirements for Fire Protection Program

STD COL 9.5-1

This COL Item is addressed as follows:

Qualification requirements for individuals responsible for development of the Fire Protection Program are discussed in Subsections 9.5.1.6 and 9.5.1.8.7.

Training of firefighting personnel is discussed in Subsections 9.5.1.8, 9.5.1.8.2, and 9.5.1.8.7.

Administrative procedures and controls governing the Fire Protection Program during plant operation are discussed in Subsections 9.5.1.8.1.2, 9.5.1.8.3, 9.5.1.8.4, 9.5.1.8.5, and 9.5.1.8.6.

Fire protection system maintenance is discussed in Subsection 9.5.1.8.6.

PTN COL 9.5-2

9.5.1.9.2 Fire Protection Analysis Information

This COL Item is addressed in Subsection 9A.3.3.

9.5.1.9.3 Regulatory Conformance

STD COL 9.5-3

This COL Item is addressed in Subsections 9.5.1.8.1.1, 9.5.1.8.8, and 9.5.1.8.9, and in Table 9.5-201.

9.5.1.9.4 NFPA Exceptions

STD COL 9.5-4 This COL item is addressed in Subsection 9.5.1.8.1.1.

9.5.1.9.6 Verification of Field Installed Fire Barriers

STD COL 9.5-6 This COL Item is addressed in Subsection 9.5.1.8.6.

9.5.1.9.7 Establishment of Procedures to Minimize Risk for Fire Areas Breached During Maintenance

STD COL 9.5-8 This COL item is addressed in Subsection 9.5.1.8.1.2.

Add the following subsection at the end of DCD Subsection 9.5.2.2.4.

9.5.2.2.5 Offsite Interfaces and Emergency Offsite Communications

PTN COL 9.5-9
PTN COL 9.5-10 Offsite interfaces and emergency offsite communications are described in the Emergency Plan.

9.5.2.5 Combined License Information

9.5.2.5.1 Offsite Interfaces

PTN COL 9.5-9 This COL Item is addressed in Subsection 9.5.2.2.5.

9.5.2.5.2 Emergency Offsite Communications

PTN COL 9.5-10 This COL Item is addressed in Subsection 9.5.2.2.5.

9.5.2.5.3 Security Communications

STD COL 9.5-11 This COL Item is addressed in the Physical Security Plan.

Add the following subsection after DCD Subsection 9.5.4.5.1.

9.5.4.5.2 Fuel Oil Quality

STD COL 9.5-13 The diesel fuel oil testing program requires testing both new fuel oil and stored fuel oil. High fuel oil quality is provided by specifying the use of ASTM Grade 2D fuel oil with a sulfur content as specified by the engine manufacturer.

A fuel sample is analyzed prior to addition of ASTM Grade 2D fuel oil to the storage tanks. The sample moisture content and particulate or color is verified per ASTM D4176. In addition, kinematic viscosity is tested to be within the limits specified in Table 1 of ASTM D975. The remaining critical parameters per Table 1 of ASTM D975 are verified compliant within 7 days.

Fuel oil quality is verified by sample every 92 days to meet ASTM Grade 2D fuel oil criteria. The addition of fuel stabilizers and other conditioners is based on sample results.

The fuel oil storage tanks are inspected on a monthly basis for the presence of water. Any accumulated water is to be removed.

9.5.4.7 Combined License Information

9.5.4.7.2 Fuel Degradation Protection

STD COL 9.5-13 This COL Item is addressed in Subsection 9.5.4.5.2.

9.5.5 REFERENCES

201. National Fire Protection Association, *Standard for Inspection, Care, and Use of Fire Hose Couplings, and Nozzles and the Service Testing of Fire Hose*, NFPA 1962, 2003.

202. National Fire Protection Association, *Standard for Fire Prevention During Welding, Cutting, and Other Hot Work*, NFPA 51B, 2003.

203. National Fire Protection Association, *Standard for Safeguarding Construction, Alteration, and Demolition Operations*, NFPA 241, 2004.

204. National Fire Protection Association, *Standard on Industrial Fire Brigades*, NFPA 600, 2005.

205. National Fire Protection Association, *Recommended Practice for Pre-Incident Planning*, NFPA 1620, 2003.

206. National Fire Protection Association, *Standard Methods of Fire Tests for Flame Propagation of Textiles and Films*, NFPA 701, 2004.

207. National Fire Protection Association, *Standard for Fire-Retardant Treated Wood and Fire-Retardant Coatings for Building Materials*, NFPA 703, 2006.

208. National Fire Protection Association, *Standard for Fire Service Respiratory Protection Training*, NFPA 1404, 2006.

209. National Fire Protection Association, *Standard on Training for Initial Emergency Scene Operations*, NFPA 1410, 2005.

210. National Fire Protection Association, *Standard on Fire Department Occupational Safety and Health Program*, NFPA 1500, 2007.

211. National Fire Protection Association, *Standard for Fire Protection for Advanced Light Water Reactor Electric Generating Plants*, NFPA 804, 2001.

212. National Fire Protection Association, *Standard for the Inspection, Testing, and Maintenance of Water-based Fire Protection Systems*, NFPA 25, 2008.

PTN DEP 6.3-1

TABLE 9.5.1-1R
AP1000 FIRE PROTECTION PROGRAM COMPLIANCE WITH BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Safe Shutdown Capability			
72. Fire damage should be limited so that one train of systems necessary to achieve and maintain hot shutdown conditions from either the main control room or emergency control station is free of fire damage.	C.5.b(1)	C	
73. Fire damage should be limited so that systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station can be repaired within 72 hours.	C.5.b (1)	AC	Safe shutdown following a fire is defined for the AP1000 plant as the ability to achieve and maintain the reactor coolant system (RCS) temperature below 215.6°C (420°F) without uncontrolled venting of the primary coolant from the RCS. This is a departure from the criteria applied to the evolutionary plant designs, and the existing plants where safe shutdown for fires applies to both hot and cold shutdown capability. With expected RCS leakage, the AP1000 plant can maintain safe shutdown conditions for greater than 14 days. Therefore, repairs to systems necessary to reach cold shutdown need not be completed within 72 hours.
74. Separation requirements for verifying that one train of systems necessary to achieve and maintain hot shutdown is free of fire damage.	C.5.b (2)	C	

Notes:

1. Compliance with NUREG-0800 Section 9.5.1, Branch Technical Position CMEB 9.5-1 is indicated by the following codes:
   - C - Compliance: AP1000 is committed to compliance with the guideline.
   - AC - Alternate Compliance: compliance with the guideline by alternate means or intent. Alternative means or design are provided in the remarks column.

Table 9.5-201[a] (Sheet 1 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

	BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
	Fire Protection Program			
STD COL 9.5-3 STD COL 9.5-4	1. Direction of fire protection program; availability of personnel.	C.1.a(1)	C	Comply. Subsections 9.5.1.8.1.2 and 13.1.1.2.10 address this requirement.
	2. Defense-in-depth concept; objective of fire protection program.	C.1.a(2)	C	Comply. Subsections 9.5.1.8 and 9.5.1.8.1 address this requirement.
PTN COL 9.5-3 PTN COL 9.5-4	3. Management responsibility for overall fire protection program; delegation of responsibility to staff.	C.1.a(3)	C	Comply. Subsections 9.5.1.8.1.2, 13.1.2.1.3.9, and 13.1.1.2.10.
	4. The staff should be responsible for: a. Fire protection program requirements. b. Post-fire shutdown capability. c. Design, maintenance, surveillance, and quality assurance of fire protection features. d. Fire prevention activities. e. Fire brigade organization and training. f. Pre-fire planning.	C.1.a(3)	C	Comply. Subsection 13.1.2.1.3.9 addresses this requirement.

Table 9.5-201[(a)] (Sheet 2 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

		BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
PTN COL 9.5-3 PTN COL 9.5-4	5.	The organizational responsibilities and lines of communication pertaining to fire protection should be defined through the use of organizational charts and functional descriptions.	C.1.a(4)	C	Comply. Organization and lines of communication are addressed in Figure 13.1-201. Functional descriptions are addressed in Subsections 13.1.1.2.10, 13.1.1.3.1.3, 13.1.2.1.3.9, and 13.1.2.1.5.
	6.	Personnel qualification requirements for fire protection engineer, reporting to the position responsible for formulation and implementation of the fire protection program.	C.1.a(5)(a)	C	Comply. Subsection 13.1.2.1.3.9 addresses this requirement.
STD COL 9.5-3 STD COL 9.5-4	7.	The fire brigade members' qualifications should include a physical examination for performing strenuous activity, and the training described in Position C.3.d.	C.1.a(5)(b)	C	Comply. Subsections 9.5.1.8.2.1 and 9.5.1.8.2.2 addresses this requirement.
	8.	The personnel responsible for the maintenance and testing of the fire protection systems should be qualified by training and experience for such work.	C.1.a(5)(c)	C	Comply. Subsection 9.5.1.8.7 addresses this requirement.
	9.	The personnel responsible for the training of the fire brigade should be qualified by training and experience for such work.	C.1.a(5)(d)	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
	10.	The following NFPA publications should be used for guidance to develop the fire protection program: No. 4, No. 4A, No. 6, No. 7, No. 8, and No. 27.	C.1.a(6)	C	Alternate Compliance. The NFPA codes cited in BTP CMEB 9.5-1 are historical. Current NFPA codes are referenced for guidance for the fire protection program. Subsection 9.5.1.8.1.1 addresses this requirement.

Table 9.5-201[(a)] (Sheet 3 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

		BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
PTN COL 9.5-3 PTN COL 9.5-4	11.	On sites where there is an operating reactor, and construction or modification of other units is underway, the superintendent of the operating plant should have a lead responsibility for site fire protection.	C.1.a(7)	C	Comply. Subsection 13.1.1.2.10 addresses this requirement. Units 6 & 7 are sufficiently separated from Units 3 & 4.
	Fire Protection Analysis				
STD COL 9.5-3 STD COL 9.5-4	14.	Fires involving facilities shared between units should be considered.	C.1.b	C	Comply. The FHA demonstrates the plant's ability to perform safe shutdown functions and minimize radioactive releases to the environment. Postulated fires in shared facilities that do not contain SSCs important to safety and do not contain radioactive materials do not affect these functions.
	15.	Fires due to man-made site-related events that have a reasonable probability of occurring and affecting more than one reactor unit should be considered.	C.1.b	C	Comply. Subsections 2.2.3 and 3.5 establish that these events are not credible.
	Fire Suppression System Design Basis				
	22.	Fire protection systems should retain their original design capability for potential man-made, site-related events that have a reasonable probability of occurring at a specific plant site.	C.1.c(4)	C	Comply. Subsections 2.2.3 and 3.5 establish that these events are not credible.
	Fire Protection Program Implementation				
	26.	The fire protection program for buildings storing new reactor fuel and for adjacent fire areas that could affect the fuel storage area should be fully operational before fuel is received at the site.	C.1.e(1)	C	Comply. Subsection 9.5.1.8.1 addresses this requirement.

Table 9.5-201[(a)] (Sheet 4 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

		BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
STD COL 9.5-3 STD COL 9.5-4	27.	The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that unit.	C.1.e(2)	C	Comply. Subsection 9.5.1.8.1 addresses this requirement.
	28.	Special considerations for the fire protection program on reactor sites where there is an operating reactor and construction or modification of other units is under way.	C.1.e(3)	C	Comply. Subsection 9.5.1.8.1.2. m addresses this requirement.
	29.	Establishing administrative controls to maintain the performance of the fire protection system and personnel.	C.2	C	Comply. Subsection 9.5.1.8.1.2 addresses this requirement.
	Fire Brigade				
	30.	The guidance in Regulatory Guide 1.101 should be followed as applicable.	C.3.a	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
PTN COL 9.5-3 PTN COL 9.5-4	31.	Establishing site brigade: minimum number of fire brigade members on each shift; qualification of fire brigade members; competence of brigade leader.	C.3.b	C	Comply. Subsections 9.5.1.8.1.2 and 13.1.2.1.5 address this requirement.
STD COL 9.5-3 STD COL 9.5-4	32.	The minimum equipment provided for the brigade should consist of turnout coats, boots, gloves, hard hats, emergency communications equipment, portable ventilation equipment, and portable extinguishers.	C.3.c	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
	33.	Recommendations for breathing apparatus for fire brigade, damage control, and control room personnel.	C.3.c	C	Comply. Subsection 9.5.1.8.2.2 and DCD Subsections 6.4.2.3 and 6.4.4 address these requirements

Table 9.5-201[(a)] (Sheet 5 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

	BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
STD COL 9.5-3 STD COL 9.5-4	34. Recommendations for the fire brigade training program.	C.3.d	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
	Quality Assurance Program			
	35. Establishing quality assurance (QA) programs by applicants and contractors for the fire protection systems for safety-related areas; identification of specific criteria for quality assurance programs.	C.4	C	Comply. DCD Subsection 9.5.1.7 and Chapter 17 address this requirement.
	Building Design			
	50. Fire doors should be inspected semiannually to verify that automatic hold-open, release, and closing mechanisms and latches are operable.	C.5.a (5)	C	Comply. Subsection 9.5.1.8.8 addresses this requirement.
	51. Alternative means for verifying that fire doors protect the door opening as required in case of fire.	C.5.a (5)	C	Comply. Subsection 9.5.1.8.8 addresses this requirement.
	52. The fire brigade leader should have ready access to keys for any locked fire doors.	C.5.a (5)	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
	55. Stairwells serving as escape routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown should be enclosed in masonry or concrete towers with a minimum fire resistance rating of 2 hours and self-closing Class B fire doors.	C.5.A (6)	C	Comply. Subsection 9A.3.3 addresses this requirement for miscellaneous buildings located in the yard.
	56. Fire exit routes should be clearly marked.	C.5.a (7)	C	Comply. DCD Subsection 9.5.1.2.1.1 addresses this requirement.

Table 9.5-201[(a)] (Sheet 6 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

	BTP CMEB 9.5-1 Guideline		Paragraph	Comp	Remarks
STD COL 9.5-3 STD COL 9.5-4	71.	Water drainage from areas that may contain radioactivity should be collected, sampled, and analyzed before discharge to the environment.	C.5.a(14)	C	Comply. Capability is provided. Subsection 9.5.1.8.5 addresses this requirement.
	Control of Combustibles				
	80.	Use of compressed gases inside buildings should be controlled.	C.5.d (2)	C	Comply. Subsection 9.5.1.8.4.g addresses this requirement.
	Lighting and Communication				
PTN COL 9.5-3 PTN COL 9.5-4	111.	A portable radio communications system should be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown.	C.5.g (4)	C	Comply. Subsections 9.5.1.8.1.2.a.3.v, 9.5.1.8.2.2, 9.5.2.2.5, and DCD Subsections 9.5.2 and 9.5.2.2.1 address this requirement.
	Water Sprinkler and Hose Standpipe Systems				
STD COL 9.5-3 STD COL 9.5-4	149.	All valves in the fire protection system should be periodically checked to verify position.	C.6.c (2)	C	Comply. Subsection 9.5.1.8.6 addresses this requirement.
	157.	The fire hose should be hydrostatically tested in accordance with NFPA 1962. Hoses stored in outside hose houses should be tested annually. The interior standpipe hose should be tested every 3 years.	C.6.c (6)	C	Comply. Subsection 9.5.1.8.6 addresses this requirement.
	Primary and Secondary Containment				
	174.	Self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should be independent of any breathing apparatus provided for general plant activities.	C.7.a (2)	C	Comply. Subsection 9.5.1.8.2.2 addresses this requirement.

Table 9.5-201[(a)] (Sheet 7 of 7)
AP1000 Fire Protection Program Compliance with BTP CMEB 9.5-1

	BTP CMEB 9.5-1 Guideline	Paragraph	Comp	Remarks
	Main Control Room Complex			
	180. Breathing apparatus for main control room operators should be readily available.	C.7.b	C	Comply. DCD Subsection 6.4.2.3 addresses this requirement.
	Cooling Towers			
STD COL 9.5-3 STD COL 9.5-4	225. Cooling towers should be of noncombustible construction or so located and protected that a fire will not adversely affect any safety-related systems or equipment.	C.7.q	C	Comply. Subsection 9A.3.3 addresses this requirement.
	Storage of Acetylene-Oxygen Fuel Gases			
	228. Gas cylinder storage locations should not be in areas that contain or expose safety-related equipment or the fire protection systems that serve those safety-related areas.	C.8.a	C	Comply. Subsection 9.5.1.8.4.g addresses this requirement.
	229. A permit system should be required to use this equipment in safety-related areas of the plant.	C.8.a	C	Comply. Subsection 9.5.1.8.4.g addresses this requirement.
	Storage Areas for Ion Exchange Resins			
	230. Unused ion exchange resins should not be stored in areas that contain or expose safety-related equipment.	C.8.b	C	Comply. Subsection 9.5.1.8.4.a addresses this requirement.
	Hazardous Chemicals			
	231. Hazardous chemicals should not be stored in areas that contain or expose safety-related equipment.	C.8.c	C	Comply. Subsection 9.5.1.8.4.h addresses this requirement.

(a) This table supplements DCD Table 9.5.1-1.

Table 9.5-202[(a)]
Exceptions to NFPA Standard Requirements

	Requirement	AP1000 Exception or Clarification
PTN COL 9.5-4	NFPA 804 (Reference 211) contains requirements specific to light water reactors.	Compliance with portions of this standard is as identified within DCD Section 9.5.1 and WCAP-15871.

(a) This table supplements DCD Table 9.5.1-3.

APPENDIX 9A FIRE PROTECTION ANALYSIS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

9A.2 FIRE PROTECTION ANALYSIS METHODOLOGY

9A.3 FIRE AREA DESCRIPTION

Add the following information at the end of the first paragraph in DCD Subsection 9A.2.1:

PTN DEP 18.8-1 DCD Figure 9A-3 (Sheet 1 of 3) is modified to reflect the relocation of the Operations Support Center by changing the description of room number 40318 from “ALARA BRIEFING RM AND OPERATIONAL SUPPORT CENTER” to “ALARA BRIEFING RM.”

9A.3.3 YARD AREA AND OUTLYING BUILDINGS

Replace the second sentence of DCD Subsection 9A.3.3 with the following information.

PTN COL 9.5-2 Miscellaneous yard areas do not contain safety-related components or systems, do not contain radioactive materials, and are located such that a fire or effects of a fire, including smoke, do not adversely affect any safety-related systems or equipment. Miscellaneous areas include such structures, for example, as maintenance shops, warehouses, the administrative building, training/office centers, and flammable and combustible material storage tanks. The miscellaneous areas are located outside of the nuclear island, which is separated from the other yard areas by 3-hour fire rated barriers. Fire detection and suppression are provided as determined by the fire hazards analysis and applicable building codes and insurance company loss prevention standards.

The cooling towers are not used as the ultimate heat sink or for fire protection purposes. Therefore, the guidance specified by BTP CMEB 9.5-1 is not applicable, except the cooling towers comply with guidance specified by BTP

CMEB 9.5-1 in that they are so located that a fire will not adversely affect any safety-related systems or equipment (Table 9.5-201, Item 225). The cooling tower serves no safety-related function and has no nuclear safety design basis. The cooling tower does not contain any equipment capable of releasing radioactivity to the atmosphere. The cooling towers, with their circulating water pump structure, are remotely located from HVAC air intakes such that smoke and products of combustion do not affect any safety-related plant areas.

STD COL 9.5-3 Stairwells in miscellaneous buildings located in the yard serving as escape routes or access routes for firefighting, are enclosed in masonry or concrete towers with a minimum fire resistance rating of 2 hours and self-closing Class B fire doors. The two-hour fire-resistance rating for the masonry or concrete material is based on testing conducted in accordance with ASTM E119 (Reference 201) and NFPA 251 (Reference 202).

9A.4 REFERENCES

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201. American Society of Mechanical Engineers, *Standard Test Methods for Fire Tests of Building Construction and Materials*, ASTM E119-08a.

202. National Fire Protection Association, *Standard Methods of Tests of Fire Endurance of Building Construction and Materials*, NFPA 251, 2006.

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CHAPTER 10 STEAM AND POWER CONVERSION

10.1 SUMMARY DESCRIPTION

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

10.1.3 COMBINED LICENSE INFORMATION ON EROSION-CORROSION MONITORING

Add the following at the end of DCD Subsection 10.1.3.

10.1.3.1 Erosion-Corrosion Monitoring

STD COL 10.1-1

The flow accelerated corrosion (FAC) monitoring program analyzes, inspects, monitors and trends those nuclear power plant components that are potentially susceptible to erosion-corrosion damage such as carbon steel components that carry wet steam. In addition, the FAC monitoring program considers the information of Generic Letter 89-08, EPRI NSAC-202L-R3, and industry operating experience. The program requires a grid layout for obtaining consistent pipe thickness measurements when using Ultrasonic Test Techniques. The FAC program obtains actual thickness measurements for highly susceptible FAC locations for new lines as defined in EPRI NSAC-202L-R3 (Reference 201). At a minimum, a CHECWORKS type Pass 1 analysis is used for low and highly susceptible FAC locations and a CHECWORKS type Pass 2 analysis is used for highly susceptible FAC locations when the Pass 1 analysis results warrant. To determine wear of piping and components where operating conditions are inconsistent or unknown, the guidance provided in EPRI NSAC-202L is used to determine wear rates.

10.1.3.1.1 Analysis

An industry-sponsored program is used to identify the most susceptible components and to evaluate the rate of wall thinning for components and piping potentially susceptible to FAC. Each susceptible component is tracked in a database and is inspected, based on susceptibility. Analytical methods utilize the results of plant-specific inspection data to develop plant-specific correction factors. This correction accounts for uncertainties in plant data, and for systematic

discrepancies caused by plant operation. For each piping component, the analytical method predicts the wear rate, and the estimated time until it must be re-inspected, repaired, or replaced. Carbon steel piping (ASME III and B31.1) that is used for single or multi-phase high temperature flow are the most susceptible to erosion-corrosion damage and receive the most critical analysis.

10.1.3.1.2 Industry Experience

Review and incorporation of industry experience provides a valuable supplement to plant analysis. Industry experience is used to update the program by identifying susceptible components or piping features.

10.1.3.1.3 Inspections

Wall thickness measurements establish the extent of wear in a given component, provide data to help evaluate trends, and provide data to refine the predictive model. Components are inspected for wear using ultrasonic techniques (UT), radiography techniques (RT), or by visual observation. The initial inspections are used as a baseline for later inspections. Each subsequent inspection determines the wear rate for the piping and components and the need for inspection frequency adjustment for those components.

10.1.3.1.4 Training and Engineering Judgement

The FAC program is administered by both trained and experienced personnel. Task specific training is provided for plant personnel that implement the monitoring program. Specific nondestructive examination (NDE) is carried out by personnel qualified in the given NDE method. Inspection data is analyzed by engineers or other experienced personnel to determine the overall effect on the system or component.

10.1.3.1.5 Long-Term Strategy

This strategy focuses on reducing wear rates and performing inspections on the most susceptible locations.

10.1.3.2 Procedures

10.1.3.2.1 Generic Plant Procedure

The FAC monitoring program is governed by procedure. This procedure contains the following elements:

- A requirement to monitor and control FAC.
- Identification of the tasks to be performed and associated responsibilities.
- Identification of the position that has overall responsibility for the FAC monitoring program at each plant.
- Communication requirements between the coordinator and other departments that have responsibility for performing support tasks.
- Quality Assurance requirements.
- Identification of long-term goals and strategies for reducing high FAC wear rates.
- A method for evaluating plant performance against long-term goals.

10.1.3.2.2 Implementing Procedures

The FAC implementing procedures provide guidelines for controlling the major tasks. The plant procedures for major tasks are as follows:

- Identifying susceptible systems.
- Performing FAC analysis.
- Selecting and scheduling components for initial inspection.
- Performing inspections.
- Evaluating degraded components.
- Repairing and replacing components when necessary.
- Selecting and scheduling locations for the follow-on inspections.
- Collection and storage of inspections records.

10.1.3.3 Plant Chemistry

The responsibility for system chemistry is under the purview of the plant chemistry section. The plant chemistry section specifies chemical addition in accordance with plant procedures.

Add the following after DCD Subsection 10.1.3:

10.1.4 REFERENCES

201. Electric Power Research Institute, *Recommendations for an Effective Flow—Accelerated Corrosion Program (NSAC-202L-R3)*, EPRI Report TR-1011838, Palo Alto, California, 2006.

10.2 TURBINE-GENERATOR

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

10.2.2 SYSTEM DESCRIPTION

Add the following sentence at the end of the second paragraph of DCD Subsection 10.2.2.

STD SUP 10.2-1 Subsection 3.5.1.3 addresses the probability of generation of a turbine missile for AP1000 plants in a side-by-side configuration.

Add the following statement at the end of DCD Subsection 10.2.2

STD SUP 10.2-4 Preoperational and startup tests provide guidance to operations personnel to ensure the proper operability of the turbine generator system.

10.2.3 TURBINE ROTOR INTEGRITY

Add the following statement at the end of DCD Subsection 10.2.3.

STD SUP 10.2-5 Operations and maintenance procedures mitigate the following potential degradation mechanisms in the turbine rotor and buckets/blades: pitting, stress corrosion cracking, corrosion fatigue, low-cycle fatigue, erosion, and erosion-corrosion.

10.2.3.6 Maintenance and Inspection Program Plan

Add the following at the end of DCD Subsection 10.2.3.6.

STD SUP 10.2-3 The inservice inspection (ISI) program for the turbine assembly provides assurance that rotor flaws that lead to brittle fracture of a rotor are detected. The ISI program also coincides with the ISI schedule during shutdown, as required by the ASME Boiler and Pressure Vessel Code, Section XI, and includes complete inspection of all significant turbine components, such as couplings, coupling bolts, turbine shafts, low-pressure turbine blades, low-pressure rotors, and high-pressure rotors. This inspection consists of visual, surface, and volumetric examinations required by the code.

10.2.6 COMBINED LICENSE INFORMATION ON TURBINE MAINTENANCE AND INSPECTION

Replace the text in DCD Subsection 10.2.6 with the following:

STD COL 10.2-1 A turbine maintenance and inspection program will be submitted to the NRC staff for review prior to fuel load. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in DCD Subsection 10.2.3.6. Plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis will be available for review after fabrication of the turbine and prior to fuel load.

10.3 MAIN STEAM SUPPLY SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

10.3.2.2.1 Main Steam Piping

Add the following at the end of DCD Subsection 10.3.2.2.1.

STD SUP 10.3-1 Operations and maintenance procedures include precautions, when appropriate, to minimize the potential for steam and water hammer, including:

- Prevention of rapid valve motion
- Process for avoiding introduction of voids into water-filled lines and components
- Proper filling and venting of water-filled lines and components
- Process for avoiding introduction of steam or heated water that can flash into water-filled lines and components
- Cautions for introduction of water into steam-filled lines or components
- Proper warmup of steam-filled lines
- Proper drainage of steam-filled lines
- The effects of valve alignments on line conditions

10.3.5.4 Chemical Addition

Add the following at the end of DCD Subsection 10.3.5.4.

STD SUP 10.3-2 Alkaline chemistry supports maintaining iodine compounds in their nonvolatile form. When iodine is in its elemental form, it is volatile and free to react with

organic compounds to create organic iodine compounds, which are not assumed to remain in solution. It is noted that no significant level of organic compounds is expected in the secondary system. The secondary water chemistry, thus, does not directly impact the radioactive iodine partition coefficients.

10.3.6.2 Material Selection and Fabrication

Add the following at the end of DCD Subsection 10.3.6.2.

STD SUP 10.3-3 Appropriate operations and maintenance procedures will provide the necessary controls during operation to minimize the susceptibility of components made of stainless steel and nickel-based materials to intergranular stress-corrosion cracking by controlling chemicals that are used on system components.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

10.4.2.2.1 General Description

Revise the first sentence of the third paragraph of DCD Subsection 10.4.2.2.1 to remove the brackets.

PTN CDI

The circulating water system (CWS) provides the cooling water for the vacuum pump seal water heat exchangers.

10.4.2.2.2 Component Description

Revise the fourth sentence of the first paragraph of DCD Subsection 10.4.2.2.2 to remove the brackets.

PTN CDI

Seal water flows through the shell side of the seal water heat exchanger and circulating water flows through the tube side.

Subsection 10.4.5 is modified using full text incorporation to provide site specific information to replace the DCD conceptual design information (CDI).

DCD

10.4.5 CIRCULATING WATER SYSTEM

10.4.5.1 Design Basis

10.4.5.1.1 Safety Design Basis

The circulating water system (CWS) serves no safety-related function and therefore has no nuclear safety design basis.

10.4.5.1.2 Power Generation Design Basis

PTN CDI

The circulating water system supplies cooling water to remove heat from the main condenser, the turbine building closed cooling water system (TCS) heat exchangers, and the condenser vacuum pump seal water heat exchangers, under varying conditions of power plant loading and design weather conditions.

DCD

10.4.5.2 System Description

10.4.5.2.1 General Description

Classification of components and equipment in the circulating water system is given in Section 3.2.

PTN COL 10.4-1

The CWS provides a heat sink for the waste heat exhausted from the steam turbine to the main condenser and dissipates this waste heat to the atmosphere using cooling towers. The CWS also provides cooling for the TCS heat exchangers and the condenser vacuum pump seal water heat exchangers. The CWS is shown in Figure 10.4-201. CWS design parameters are provided in Tables 10.4-201 and 10.4-202.

PTN CDI

The CWS consists of three 33-1/3 percent capacity circulating water pumps, three mechanical draft cooling towers, and associated piping, valves, and instrumentation per unit.

DCD

Makeup water to the CWS is provided by the raw water system (RWS). In addition, water chemistry is controlled by a local chemical feed system.

PTN CDI

The RWS includes two sources of water available for makeup water to the CWS. One source is reclaimed water from the Miami-Dade Water and Sewer Department and the second source is saltwater from the radial collector wells. The CWS is capable of operating with either water source alone and with a combination of the two sources. The reclaimed water portion of the RWS is

shown in Figure 9.2-201, Sheet 1 of 3. The saltwater portion of the RWS is shown in Figure 9.2-201, Sheet 2 of 3.

10.4.5.2.2 Component Description

DCD

Circulating Water Pumps

PTN CDI

The three circulating water pumps are vertical, wet pit, single-stage, mixed-flow pumps driven by electric motors. The pumps are mounted in an intake structure connected to the cooling tower basins by open flumes. The three pump discharge lines combine in a single main header at the intake structure. This main header with two supply lines to the turbine building forms a common header that connects to the two inlet water boxes of the condenser and may also supply cooling water to the TCS and condenser vacuum pump seal water heat exchangers. Each pump discharge line has a motor-operated butterfly valve located between the pump discharge and the main header. This permits isolation of one pump for maintenance and allows two-pump operation.

Cooling Towers

PTN COL 10.4-1

Three mechanical-induced draft, counterflow cooling towers are designed to reject a single unit's full-load waste heat to the atmosphere. The cooling towers are designed to cool the circulating water to 91°F or less based on 1 percent annual exceedance wet bulb temperature of 80.6°F. Heat is rejected to the atmosphere primarily through evaporative cooling as circulating water returned from the condenser drops through the tower fill to the tower basins from which it is returned through open flumes to the CWS intake structure. Operation of the cooling towers during conditions that are more restrictive than design conditions may result in higher condenser back pressure.

PTN CDI

When more than one cooling tower is located on a site, a portion of the saturated effluent of an upwind tower can intermix with the air entering a tower located downwind, elevating its inlet wet bulb temperature. This phenomenon is known as "interference" and it results in decreased performance of the downwind tower.

Proper cooling tower placement and orientation can minimize the effect of interference. Since the SWS and the CWS towers are located remotely to each other and the saturated effluent dissipates before it interferes with the intake of the SWS, the CWS towers would not adversely affect the performance of the SWS towers.

Cooling Tower Makeup and Blowdown

DCD

The circulating water system makeup is provided by the raw water system.

PTN CDI

Makeup to and blowdown from the CWS is controlled by the makeup and blowdown control valves, respectively. These valves, along with the local chemical feed system, provide chemistry control in the circulating water to maintain a noncorrosive, nonscale-forming condition and limit biological growth in the CWS components.

DCD

Piping and Valves

PTN CDI

The underground portions of the CWS piping are constructed of prestressed concrete pressure piping. The remainder of the piping is carbon steel and is coated internally with a corrosion-resistant compound.

PTN COL 10.4-1

Condenser water box drain lines allow the condenser to be drained to the turbine building sumps. Condenser water box drain lines can also be aligned to the cooling tower basin. Administrative controls prevent the release of circulating water radioactivity in a condenser water box to the cooling tower basin. Each water box contains drain valves and vents so that a water box can be drained individually. Piping is sized to support an adequate drain down in the event of emergency maintenance.

DCD

Motor-operated butterfly valves are provided in each of the circulating water lines at their inlet to and exit from the condenser shell to allow isolation of portions of the condenser.

PTN CDI

Control valves provide regulation of cooling tower blowdown and makeup.

DCD

The circulating water system is designed to withstand the maximum operating discharge pressure of the circulating water pumps.

PTN CDI

Piping includes the expansion joints, butterfly valves, condenser water boxes, and tube bundles.

PTN COL 10.4-1

The design pressure of the condenser portions of the piping is identified in DCD Table 10.4.1-1. The design pressure of the remaining piping is 110 psig.

DCD

Circulating Water Chemical Injection

Circulating water chemistry is maintained by a local chemical feed system skid at the CWS cooling tower.

PTN CDI

Circulating water system chemical feed equipment injects the required chemicals into the circulating water at the CWS cooling tower basin.

DCD

This maintains a noncorrosive, nonscale-forming condition and limits the biological film formation that reduces the heat transfer rate in the condenser and the heat exchangers supplied by the circulating water system.

PTN COL 10.4-1 The specific chemicals used within the system are based on water conditions as determined by CWS water chemistry.

DCD The chemicals can be divided into six categories based upon function: biocide, algaecide, pH adjuster, corrosion inhibitor, scale inhibitor, and a silt dispersant. The pH adjuster, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. The biocide application frequency may vary with seasons.

PTN CDI The algaecide is applied, as necessary, to control algae formation on the cooling tower.

PTN COL 10.4-1 The following chemicals are used to control circulating water chemistry:

- Biocide and algaecide - sodium hypochlorite
- pH adjuster - sulfuric acid
- Corrosion inhibitor/scale inhibitor/silt dispersant - High stress polymer
- Scale inhibitor - sodium salt of phosphonomethylate diamine and/or silicate inhibiting polymer

DCD Addition of biocide and water treatment chemicals is performed by local chemical feed injection metering pumps and is adjusted as required.

PTN CDI Chemical concentrations are measured through analysis of grab samples from the CWS.

DCD

Residual chlorine is measured to monitor the effectiveness of the biocide treatment.

PTN CDI

Chemical injections are interlocked with each circulating water pump to prevent chemical injection when the circulating water pumps are not running.

DCD

10.4.5.2.3 System Operation

PTN CDI

The three circulating water pumps take suction from the circulating water intake structure and circulate the water through the tube side of the main condenser, with smaller flows to the TCS and the condenser vacuum pump seal heat exchangers, and back through the piping discharge network to the cooling towers (see Figure 10.4-201). The cooling towers cool the circulating water by discharging the water above the tower fill material, through which the water then falls to the basin beneath the towers and, in the process, rejects heat to the atmosphere.

Circulating water flow to the cooling towers can be diverted to the basins, bypassing the cooling towers' internals by opening the bypass valves. The bypass can be used during plant startup or partial load or to maintain CWS temperatures above 40°F while operating during periods of cold weather.

The raw water system supplies makeup water to the cooling tower basins to replace water losses due to evaporation, drift, and blowdown. Separate connections are provided between the RWS and CWS to initially fill the CWS piping. The connections to the CWS are downstream of the CWS pump isolation valves.

DCD

A condenser tube cleaning system is installed to clean the circulating water side of the main condenser tubes.

PTN CDI

Blowdown from the circulating water system is taken from the discharge header of the circulating water system pumps, and is discharged to the blowdown sump.

DCD

The circulating water system is used to supply cooling water to the main condenser to condense the steam exhausted from the main turbine.

PTN CDI

If the circulating water system malfunctions such that the condenser backpressure rises above the maximum allowable value, the main condenser will no longer be able to adequately support unit operation.

DCD

Cooldown of the reactor may be accomplished by using the power-operated atmospheric steam relief valves or safety valves rather than the turbine bypass system when the condenser is not available.

Passage of condensate from the main condenser into the circulating water system through a condenser tube leak is not possible during power generation operation, since the circulating water system operates at a greater pressure than the condenser.

PTN CDI

Turbine building closed cooling water in the TCS heat exchangers is maintained at a higher pressure than the circulating water to prevent leakage of the circulating water into the closed cooling water system.

Cooling water to the condenser vacuum pump seal water heat exchangers is supplied from the circulating water system. Cooling water flow from the circulating water system is normally maintained through all four heat exchangers to facilitate placing the spare condenser vacuum pump in service.

DCD

Isolation valves are provided for the condenser vacuum pump seal water heat exchanger cooling water supply lines to facilitate maintenance.

Small circulating water system leaks in the turbine building will drain into the waste water system. Large circulating water system leaks due to pipe failures will be indicated in the control room by a loss of vacuum in the condenser shell. The effects of flooding due to a circulating water system failure, such as the rupture of

an expansion joint, will not result in detrimental effects on safety-related equipment since there is no safety-related equipment in the turbine building and the base slab of the turbine building is located at grade elevation. Water from a system rupture will run out of the building through a relief panel in the turbine building west wall before the level could rise high enough to cause damage. Site grading will carry the water away from safety-related buildings.

PTN CDI

Each of the mechanical draft cooling towers is positioned so that its collapse would have no potential to damage structures, systems, and components (SSCs) required for safe shutdown of the plant. External flooding resulting from a failure of the cooling tower basins, flumes or associated circulating water system piping would have no adverse effect on safety-related SSCs, due to the location of the cooling towers (greater than 600 feet from safety-related SSCs) in combination with site grading to direct surface water away from the nuclear island.

DCD

10.4.5.3 Safety Evaluation

The circulating water system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.5.4 Tests and Inspections

Components of the circulating water system are accessible as required for inspection during plant power generation.

PTN CDI

The circulating water pumps are tested in accordance with standards of the Hydraulic Institute.

DCD

Performance, hydrostatic, and leakage tests associated with preinstallation and preoperational testing are performed on the circulating water system. The system performance and structural and leaktight integrity of system components are demonstrated by continuous operation.

10.4.5.5 Instrumentation Applications

PTN CDI

Instrumentation provided indicates the open and closed positions of motor-operated butterfly valves in the circulating water piping. The motor-operated valve at each pump discharge is interlocked with the pump so that the pump trips if the discharge valve fails to reach the full-open position shortly after starting the pump.

Local grab samples are used to periodically test the circulating water quality to limit harmful effects to the system piping and valves due to improper water chemistry.

Pressure indication is provided on the circulating water pump discharge lines.

DCD

A differential pressure transmitter is provided between one inlet and outlet branch to the condenser. This differential pressure transmitter is used to determine the frequency of operating the condenser tube cleaning system (CES).

PTN CDI

Temperature indication is supplied on the common CWS inlet header to the TCS heat exchanger trains. This temperature is also representative of the inlet cooling water temperature to the main condenser.

A flow element is provided on the common discharge line from the TCS heat exchangers to allow monitoring of the total flow through the TCS heat exchangers. Flow measurement for the raw water makeup to the cooling tower and for the circulating water system blowdown is also provided.

Level instrumentation provided in the circulating water intake structure activates makeup flow from the RWS to the cooling tower basins. Level instrumentation also annunciates a low water level in the intake structure, and a high water level in the cooling tower basins.

PTN COL 10.4-1

The circulating water chemistry is controlled by CWS blowdown and chemical addition to maintain the circulating water with an acceptable Langelier Index range as described in Subsection 10.4.12.1. The system accomplishes this by regulating the blowdown valve. This regulation causes the tower basin water level to

fluctuate. This fluctuation is sensed by a level controller that operates the cooling tower makeup valves.

DCD

The control approach is to allow the makeup water to concentrate naturally to its upper limit. Provisions are made to add chemicals for pH control.

PTN CDI

The cycles of concentration at which the cooling tower is operated depends on the quality of the cooling tower makeup water. The cooling water blowdown is discharged to the blowdown sump.

DCD

Monitoring of the circulating water system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. See Chapter 7.

10.4.7.2.1 General Description

Replace the last sentence of the sixth paragraph of DCD Subsection 10.4.7.2.1 as follows.

PTN COL 10.4-2

The oxygen scavenger agent is hydrazine and/or carbohydrazide and the pH control agent is morpholine.

PTN SUP 10.4-2

Oxygen scavenging and pH control agents are selected and utilized for plant secondary water chemistry optimization following the guidance of NEI-97-06, “Steam Generator Program Guidelines” (Reference 201). The EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines are followed as described in NEI 97-06.

Add new paragraph at the end of the DCD Subsection 10.4.7.2.1:

STD SUP 10.4-1 Operations and maintenance procedures include precautions, when appropriate, to minimize the potential for steam and water hammer, including:

- Prevention of rapid valve motion
- Process for avoiding introduction of voids into water-filled lines and components
- Proper filling and venting of water-filled lines and components
- Process for avoiding introduction of steam or heated water that can flash into water-filled lines and components
- Cautions for introduction of water into steam-filled lines or components
- Proper warmup of steam-filled lines
- Proper drainage of steam-filled lines
- The effects of valve alignments on line conditions

10.4.12.1 Circulating Water System

PTN COL 10.4-1 This COL Item is addressed in Subsection 10.4.5 with specific descriptions of CWS configuration in Subsection 10.4.5.2.1, design pressure and cooling towers in Subsection 10.4.5.2.2, and specific chemicals and chemistry in Subsections 10.4.5.2.2 and 10.4.5.5.

10.4.12.2 Condensate, Feedwater and Auxiliary Steam System Chemistry Control

PTN COL 10.4-2 This COL Item is addressed in Subsection 10.4.7.2.1.

10.4.12.3 Potable Water

Replace the entire paragraph for DCD Subsection 10.4.12.3 with the following.

PTN COL 10.4-3 This COL Item is duplicated in the Subsection 9.2.13.1 COL Item and is addressed as stated in that subsection.

10.4.13 REFERENCES

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201. Nuclear Energy Institute, *Steam Generator Program Guidelines*, NEI 97-06, Rev. 2, May 2005.

PTN CDI

Table 10.4-201
Supplemental Main Condenser Design Data

Condenser Data	
Circulating water flow	600,000 gpm

Note: This table supplements DCD Table 10.4.1-1.

PTN COL 10.4-1

Table 10.4-202
Supplemental Design Parameters for Major Circulating Water System Components

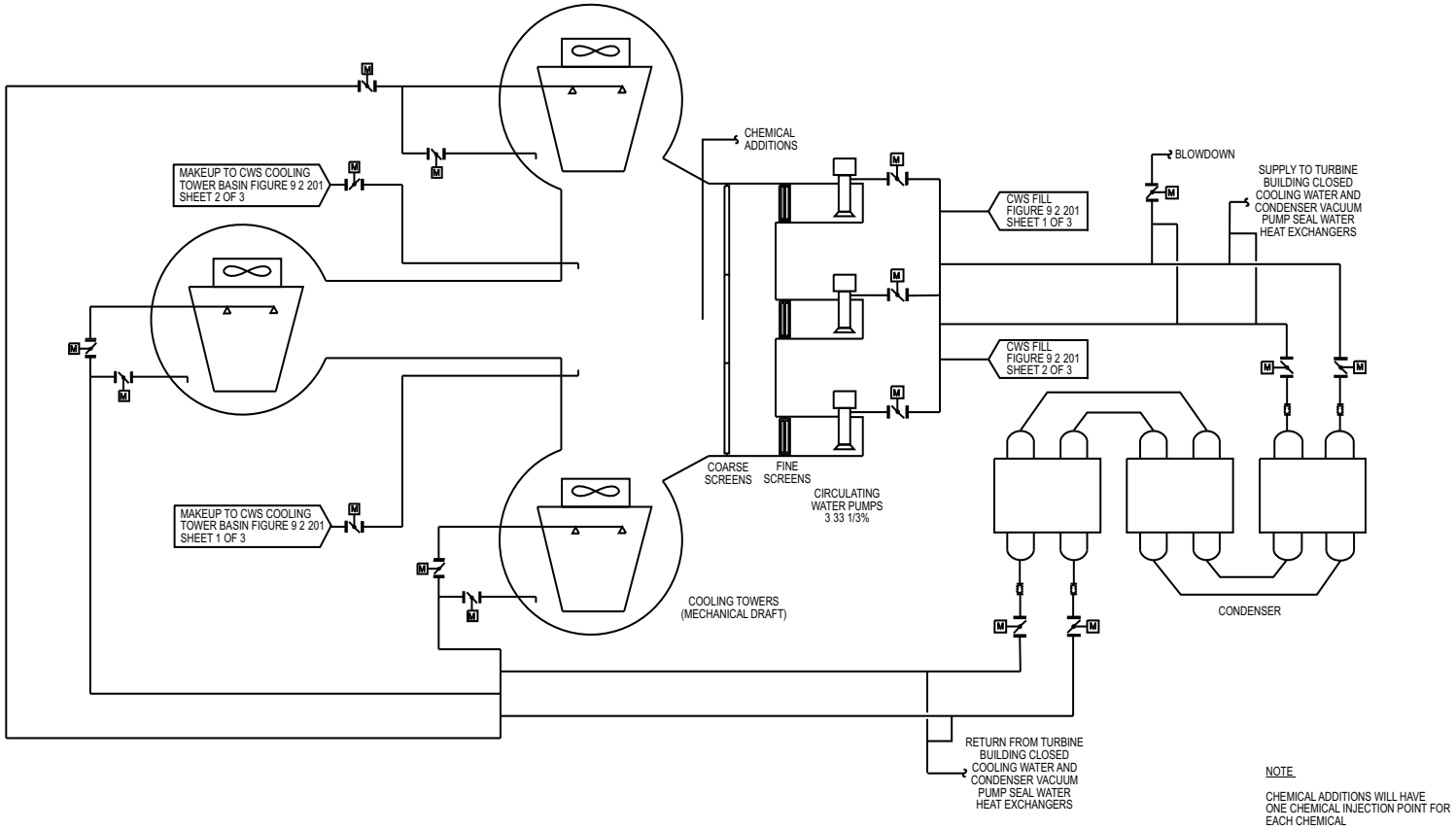
Circulating Water Pump	
Quantity	3 per unit
Flow rate (gallons/minute)	220,000

Mechanical Draft Cooling Tower	
Quantity	3 per unit
Approach temperature	7.1°F
Inlet water temperatures	115.4°F
Outlet water temperature	91°F
Approximate temperature range	24.4°F
Flow rate, each (gallons/minute)	210,000
Heat transfer, each (Btu/hour)	2.543E09
Wind velocity design (mph)	146
Seismic design criteria in accordance with Florida building code	

Note: This table supplements DCD Table 10.4.5-1.

PTN CDI

Figure 10.4-201 Circulating Water System Flow Diagram



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CHAPTER 11 RADIOACTIVE WASTE MANAGEMENT

11.1 SOURCE TERMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

PTN DEP 6.4-1

TABLE 11.1-4R
PARAMETERS USED TO CALCULATE SECONDARY COOLANT ACTIVITY

Total secondary side water mass (lb/steam generator)	1.68×10^5
Steam generator steam fraction	0.058
Total steam flow rate (lb/hr)	1.5×10^7
Moisture carryover (percent)	0.1
Total makeup water feed rate (lb/r)	700
Total blowdown rate (gpm)	186
Total primary-to-secondary leak rate (gpd)	300
Iodine partition factor (mass basis)	100

PTN DEP 6.4-1

TABLE 11.1-5R
DESIGN BASIS STEAM GENERATOR SECONDARY SIDE LIQUID ACTIVITY

Nuclide	Activity (µCi/g)	Nuclide	Activity (µCi/g)
Br-83	1.4×10^{-5}	Y-93	8.2×10^{-8}
Br-84	2.4×10^{-6}	Zr-95	1.5×10^{-7}
Br-85	3.1×10^{-8}	Nb-95	1.5×10^{-7}
I-129	1.3×10^{-11}	Mo-99	1.9×10^{-4}
I-130	7.9×10^{-6}	Tc-99m	1.7×10^{-4}
I-131	6.3×10^{-4}	Ru-103	1.2×10^{-7}
I-132	4.2×10^{-4}	Ru-106	4.1×10^{-8}
I-133	1.0×10^{-3}	Rh-103m	1.2×10^{-7}
I-134	4.9×10^{-5}	Rh-106	4.1×10^{-8}
I-135	5.0×10^{-4}	Ag-110m	3.0×10^{-6}
Rb-86	1.4×10^{-5}	Te-125m	1.5×10^{-7}
Rb-88	1.4×10^{-4}	Te-127m	7.0×10^{-7}
Rb-89	5.6×10^{-6}	Te-127	2.2×10^{-6}
Cs-134	1.1×10^{-3}	Te-129m	2.4×10^{-6}
Cs-136	1.7×10^{-3}	Te-129	2.1×10^{-6}
Cs-137	8.2×10^{-4}	Te-131m	5.6×10^{-6}
Cs-138	5.9×10^{-5}	Te-131	1.6×10^{-6}
H-3	3.8×10^{-1}	Te-132	7.0×10^{-5}
Cr-51	1.3×10^{-6}	Te-134	2.0×10^{-6}
Mn-54	6.6×10^{-7}	Ba-137m	7.7×10^{-4}
Mn-56	7.8×10^{-5}	Ba-140	9.4×10^{-7}
Fe-55	5.0×10^{-7}	La-140	3.3×10^{-7}
Fe-59	1.3×10^{-7}	Ce-141	1.4×10^{-7}
Co-58	1.9×10^{-6}	Ce-143	1.2×10^{-7}
Co-60	2.2×10^{-7}	Ce-144	1.1×10^{-7}
Sr-89	1.8×10^{-6}	Pr-143	1.4×10^{-7}
Sr-90	8.0×10^{-8}	Pr-144	1.1×10^{-7}
Sr-91	1.9×10^{-6}		
Sr-92	2.4×10^{-7}		
Y-90	1.4×10^{-8}		
Y-91m	1.0×10^{-6}		
Y-91	1.3×10^{-7}		
Y-92	2.8×10^{-7}		

PTN DEP 6.4-1

TABLE 11.1-6R
DESIGN BASIS STEAM GENERATOR SECONDARY SIDE STEAM ACTIVITY

Nuclide	Activity (μCi/g)
Kr-83m	1.1×10^{-6}
Kr-85m	4.3×10^{-6}
Kr-85	1.5×10^{-5}
Kr-87	2.4×10^{-6}
Kr-88	7.7×10^{-6}
Kr-89	1.8×10^{-7}
Xe-131m	6.9×10^{-6}
Xe-133m	8.7×10^{-6}
Xe-133	6.4×10^{-4}
Xe-135m	5.5×10^{-6}
Xe-135	1.9×10^{-5}
Xe-137	3.4×10^{-7}
Xe-138	1.3×10^{-6}
I-129	1.5×10^{-13}
I-130	8.7×10^{-8}
I-131	6.9×10^{-6}
I-132	4.7×10^{-6}
I-133	1.1×10^{-5}
I-134	5.4×10^{-7}
I-135	5.5×10^{-6}
H-3	3.8×10^{-1}

11.2 LIQUID WASTE MANAGEMENT SYSTEMS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

11.2.1.2.4 Controlled Release of Radioactivity

Add the following to the end of DCD Subsection 11.2.1.2.4:

PTN SUP 11.2-1 The guard pipe-enclosed radwaste discharge piping connects to the blowdown sump discharge piping downstream of the blowdown sump pumps. Dilution of the liquid radwaste is initiated as the radwaste enters the blowdown sump discharge stream. The content of the blowdown sump is a combination of waste streams largely comprised of reclaimed water or seawater from circulating water system blowdown during plant operation or from the alternate dilution flow paths when CWS blowdown is not sufficient or available for dilution.

Piping from the blowdown sump dilution connection point is routed to the deep injection wells, distributed in two branches; one branch is oriented in a north-south direction and located to the east of Unit 6. The second branch is oriented in the east-west direction and located to the south of Units 6 & 7, as shown on Figure 1.1-201.

This injectate piping to each deep injection well isolation valve is single-walled, partially buried, and constructed of steel. The injectate piping contains manifolds, valves, and controls necessary to supply any appropriate combination of the deep injection wells. The injectate piping also includes appurtenances, such as vacuum breakers, vent lines, and access ways, as necessary, for proper operation and maintenance of the piping.

The piping, manifolds, valves, controls, and appurtenances are designed to minimize inadvertent or unidentified releases to the environment. Integrity of the injectate piping is monitored for leakage by performing periodic visual inspection, if accessible, conducted as part of routine operation and maintenance activities or through remote surveillance in conjunction with groundwater monitoring, as necessary, as part of the Units 6 & 7 Groundwater Monitoring Program described in Subsection 2.4.12.4. NEI 08-08A, RG 4.21, and 10 CFR 20.1406 informed the design of the monitoring and leakage detection program. Monitoring points are provided to facilitate sampling for leakage consistent with contamination minimization requirements. Additionally, leakage monitoring of the liquid radwaste

system discharge pipeline and the underground pit where the liquid radwaste pipe ties into the blowdown sump discharge pipe is implemented as part of the Radiation Protection Program detailed in Appendix 12AA.

As stated in Appendix 12AA, NEI 08-08A is adopted for Turkey Point Units 6 & 7. The NEI 08-08A template guidance provides a description of the operational and programmatic elements and controls that minimize contamination of the facility, site, and the environment, to meet the requirements of 10 CFR 20.1406.

The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, Effluent Concentration Limits (ECLs), by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied before the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), an operational program identified in Table 13.4-201.

11.2.1.2.5.2 Use of Mobile and Temporary Equipment

Add the following information at the end of DCD Subsection 11.2.1.2.5.2:

STD COL 11.2-1 When mobile or temporary equipment is selected to process liquid effluents, the equipment design and testing meets the applicable requirements of Regulatory Guide 1.143. When confirmed through sampling that the radioactive waste contents result in an inventory on a mobile system that is below the A_2 quantity limit for radionuclides specified in Appendix A to 10 CFR Part 71, the liquid effluent may be processed with the mobile liquid waste processing system in the radwaste building. When pre-process sampling and controls indicate that A_2 quantity limits may be exceeded by processing liquid effluent in the radwaste building, liquid waste is processed in the Seismic Category I auxiliary building. Procedural controls also ensure that the total cumulative source term of unpackaged wastes including liquid waste, wet waste, solid waste, gaseous waste, activated or contaminated metals and components, and contaminated waste present at any time in the radwaste building is limited consistent with RG 1.143, Revision 2, unmitigated radiological release criteria (as revised by Standard Review Plan 11.2, SRP Acceptance Criterion 3), so that an unmitigated

release, occurring over a two hour time period, would not result in a dose of greater than 100 millirem at the protected area boundary, or an unmitigated exposure, occurring over a two hour time period, would not result in a dose of greater than 5 rem to site personnel located 10 feet from the total cumulative radioactive inventory. The unmitigated, unshielded worker dose is calculated at 10 feet from the source. Unlimited worker occupancy workstations and low dose rate waiting areas are located no closer than 10 feet from a mobile radwaste processing system or a Waste Monitor Tank.

Mobile and temporary equipment are designed in accordance with the applicable mobile and temporary radwaste treatment systems guidance provided in Regulatory Guide 1.143, including the codes and standards listed in Table 1 of the Regulatory Guide.

Mobile or temporary equipment has the following features:

- Level indication and alarms (high-level) on tanks.
- Screwed connections are permitted only for instrument connections beyond the first isolation valve.
- Remote operated valves are used where operations personnel would be required to frequently manipulate a valve.
- Local control panels are located away from the equipment, in low dose areas.
- Instrumentation readings are accessible from the local control panels (i.e., temperature, flow, pressure, liquid level, etc.).
- Wetted parts are 300 series stainless steel, except flexible hose and gaskets.
- Flexible hose is used only for mobile equipment within the designated “black box” locations between mobile components and at the interface with the permanent plant piping.
- The contents of tanks are capable of being mixed, either through recirculation or with a mixer.
- Grab sample points are located in tanks and upstream and downstream of the process equipment.

Inspection and testing of mobile or temporary equipment is in accordance with the codes and standards listed in Table 1 of Regulatory Guide 1.143 with the following additions:

- After placement in the station, the mobile or temporary equipment is hydrostatically, or pneumatically, tested prior to tie-in to permanent plant piping.
- A functional test, using demineralized water, is performed. Remote operated valves are stroked (open-closed-open or closed-open-closed) under full flow conditions. The proper function of the instrumentation, including alarms, is verified. The operating procedures are verified correct during the functional test.
- Tank overflows are routed to floor drains.
- Floor drains are confirmed to be functional prior to placing mobile or temporary equipment into operation.

11.2.3.5 Estimated Doses

Replace the information in DCD Subsection 11.2.3.5 with the following paragraphs and subsections.

PTN COL 11.2-2
PTN COL 11.5-3

Processed liquid radioactive waste from Turkey Point Units 6 & 7 operation is discharged to the plant blowdown sump pump discharge line before release to the Lower Floridan aquifer (Boulder Zone) by the deep well injection system (DIS) (Subsection 9.2.12). The performance assessment (PA) discussed in the following subsections is performed to assess the environmental fate and transport of Turkey Point Units 6 & 7 liquid effluent releases by deep well injection. The PA couples numerical groundwater modeling techniques with a liquid pathway analysis to identify the maximum exposed member of the public in unrestricted areas (maximally exposed individual, MEI) as a result of the Turkey Point Units 6 & 7 liquid effluent releases. The MEI is a hypothetical individual who—because of proximity, activities, or living habits—could potentially receive the maximum possible radiological dose attributed to each of three postulated deep well injection exposure pathway modes (i.e., normal operation, off-normal operation, and Inadvertent Intrusion). MEI dose is assigned using RG 1.109 dose

contribution calculations for the radionuclides retained in the PA; where necessary, independent recognized technical approaches are used to validate RG 1.109 results. The groundwater modeling portion of the PA is conducted independent of RG 1.109 since that NRC guidance solely addresses surface water transport. The regulatory criteria applied in interpreting the MEI dose assignments are the single reactor 10 CFR Part 50, Appendix I, calendar year design objectives: less than or equal to 3 mrem to the total body and less than or equal to 10 mrem to the critical organ. MEI dose assignments attributable to the operational flexibility allowed by the calendar quarter Appendix I numerical guidance on technical specifications defining limiting conditions for operation are not explored in the PA because this guidance is specifically intended to allow operational flexibility in response to actual, as opposed to estimated, releases from the plant under unusual conditions. Doing so requires unreasonable speculation about in-plant liquid effluent generation or processing upsets.

11.2.3.5.1 Fate and Transport of Injected Radionuclides in the Subsurface

Turkey Point Units 6 & 7 disposes of liquid wastewater effluent via deep well injection into the Boulder Zone. To evaluate the fate and transport of radionuclides injected into the Boulder Zone, a variable-density numerical groundwater flow model is developed. A variable-density model is selected because density differentials between the injectate and the in situ groundwater are expected to have a significant impact on the flow and transport regimes, as described below.

The source term used in this model is based on a screening analysis of the entire DCD Table 11.2-7 inventory. This screening analysis, as described in the *Radioactive Source Term Selection* section, identifies four radionuclides (tritium, cesium-134, cesium-137 and strontium-90) that are the most significant potential dose contributors. These four radionuclides are retained throughout the variable-density flow and transport modeling calculations.

11.2.3.5.1.1 Groundwater Modeling

To support the evaluation of potential impacts to members of the public and doses to the MEI due to operation of the Turkey Point Units 6 & 7 DIS, the following models are developed:

Radial Transport Model In the Boulder Zone: models the fate and radial transport of radionuclides injected into the Boulder Zone.

Vertical Transport Model: models the upward transport of injectate out of the Boulder Zone.

Each analysis/model is described in detail below.

11.2.3.5.1.1.1 Radial Transport Model In the Boulder Zone

To evaluate the fate and transport of radionuclides injected into the Boulder Zone, a variable-density numerical groundwater flow model is developed. A variable-density model is selected because density differentials between the injectate (cycled reclaimed water or saltwater) and the in situ groundwater are expected to have an impact on the flow and transport regimes in the Boulder Zone.

This model considers the Boulder Zone (i.e., injection zone) only; other aquifer and/or confining units are not taken into account. The Boulder Zone is modeled as a confined (non-leaky) aquifer, neglecting other aquifer and/or confining units, which is conservative with respect to modeling radial transport because solutes (radionuclides) cannot leave the system by vertical leakance.

The elements of the numerical model for the base case, including the development of the input parameters and predicted radionuclide activity concentrations at potential receptor locations are described in the following paragraphs. A base case scenario is first developed, followed by a series of sensitivity analyses.

Radioactive Source Term Selection

Development of injectate activity concentrations takes into consideration the entire DCD Table 11.2-7 inventory. Radionuclide-specific activity concentrations are then determined on a basis consistent with that upon which DCD Table 11.2-8 has been developed.

A screening analysis is performed using the LADTAP II computer code (NUREG/CR-4013) to identify the DCD Table 11.2-7 radionuclides that are the most significant potential dose contributors considering the ingestion pathways of drinking water and irrigated milk, meats, and vegetables for effluent decay times ranging from 5 to 100 years. Based on this analysis, tritium, strontium-90, cesium-134, and cesium-137 are determined to contribute over 99 percent of the dose to the total body and the organs of a child (the most conservative receptor) after a decay time of 10 years or more. As discussed in greater detail in Subsection 11.2.3.5.2.5.1, the injectate plume is not projected to reach the receptor location until approximately 10 years after initiation of injection (for the base case simulation). These four radionuclides are, therefore, retained for further fate, transport modeling, and subsequent dose analysis. The injectate activity concentrations of these four radionuclides are presented in Table 11.2-201.

Numerical Model Description and Development of Model Input Parameters

Numerical Model Description

Depending on the source of cooling water makeup (reclaimed water or saltwater), the deep well injectate blowdown may be less or more dense than the in situ Boulder Zone groundwater. The injectate is less dense than the in situ groundwater when reclaimed water is used for cooling water makeup and more dense when saltwater is used.

To account for these density differences and their impact on radionuclide transport, SEAWAT, a finite-difference, variable-density groundwater code (Reference 202) is used to model the fate and transport of radionuclides injected into the Boulder Zone. SEAWAT solves the three-dimensional (3D), variable-density groundwater flow and multi-species transport equations by coupling MODFLOW (Reference 203) and MT3DMS (References 204 and 205). SEAWAT is widely used to simulate variable-density groundwater flow and is maintained by the U.S. Geological Survey. Groundwater Vistas (Reference 206) is used as a preprocessor and postprocessor to facilitate development of the model and interpretation of model results.

Modeling Approach

The DIS injection field is simulated using an axisymmetric approach, which represents a radially symmetric 3D system as a two-dimensional model (Reference 207). With this approach, the DIS injection field is represented as a single well and provides a computationally efficient alternative to a full 3D model (Reference 207). This approach is appropriate given the absence of a strong regional hydraulic gradient in the Boulder Zone (Reference 208) relative to that likely to be induced by the injection.

Model Domain, Parameters, and Boundary Conditions

The model domain extends approximately 15 miles radially from the point of injection. This distance is selected to fully encompass the anticipated radial extent of the injectate plume over the life of the facility. The Boulder Zone is assumed to be homogeneous for the purpose of assigning groundwater flow and transport parameters. These parameters include transmissivity, storativity, effective porosity, and longitudinal and vertical dispersivity (Table 11.2-202).

The principal injectate component is wastewater from the main condenser cooling system (blowdown). Therefore, the main condenser cooling system makeup water

source determines the fundamental hydrological characteristics of the injectate. The base case modeling scenario is predicated on the use of reclaimed water as the makeup water source. The intermittent use of saltwater as a makeup water source and its effect on radionuclide transport is also assessed, as are variations in the other operational parameters upon which the groundwater model is predicated (Table 11.2-203).

With a projected 60-year operational life (40-year license and 20-year renewal) per unit and a 1-year interval between the startup of Unit 6 and Unit 7, the total time period spanned by the operation of both units is 61 years. The groundwater model simulation duration is 100 years, which includes 61 years of DIS operation followed by 39 years without injection. This 39-year period is simulated to evaluate radionuclide migration after injection ceases.

In the event that reclaimed water is not available in sufficient quality or quantity, Turkey Point Units 6 & 7 uses saltwater provided by radial collector wells as a backup water source. The use of saltwater is limited to a maximum of 60 days in any consecutive 12-month period (References 215 and 216). While using saltwater as the source of cooling water, the injection flow rate (58,175 gpm) is approximately five times greater than that when using reclaimed water and the resulting radionuclide concentrations are approximately five times lower.

11.2.3.5.1.1.2 Vertical Transport Model

Given the depth of the Boulder Zone and the high salinity of the groundwater it contains, it is considered unlikely that the Boulder Zone will be accessed directly as a source of supply for either irrigation or ingestion purposes. However, the Upper Floridan aquifer is already being used as a source of supply for irrigation purposes in the vicinity of the Turkey Point Units 6 & 7 site. Therefore, the potential scenarios under which a member-of-the-public exposure to effluent injected into the Boulder Zone may occur are, in part, a function of the expected ability of the overlying middle confining unit to preclude upward migration of injectate out of the Boulder Zone and into the Upper Floridan aquifer.

The primary mechanism for migration of injectate out of the Boulder Zone is upward flow due to the injection pressure and the density differential between the injected fluid and the in situ groundwater. Cooling water sourced from reclaimed water has the potential for upward migration due to its relatively low total dissolved solids (TDS) concentration and correspondingly low density compared to groundwater in the Boulder Zone, while cooling water derived from saltwater (radial collector wells) will tend to sink due to a high TDS concentration and,

therefore, does not pose a risk of upward vertical migration. While TDS concentration is the primary determinant of fluid density for the expected range of conditions, temperature can also contribute to density differentials.

To evaluate the potential for upward migration from the Boulder Zone through the middle confining unit to the Upper Floridan aquifer absent some failure such as an improperly abandoned well, naturally formed conduit, etc., a 3D groundwater model is developed to simulate injection of reclaimed water into the Boulder Zone. The modeling is also performed using SEAWAT (Reference 202) and included consideration of fluid density variations due to both TDS concentration and temperature. Solute transport modeling is performed for TDS concentration, which serves as a non-decaying radionuclide surrogate.

Based on the modeling results, the migration of radioactive species out of the Boulder Zone by density-driven vertical migration is not expected to be significant.

11.2.3.5.1.2 Cumulative Radionuclide Inventory at the End of Plant Operations

The cumulative radionuclide inventory present in the Boulder Zone at the end of Turkey Point Units 6 & 7 plant operations is presented in Table 11.2-204. This table represents the DCD Table 11.2-7 inventory continually injected into the Boulder Zone for 61 years, with radioactive decay being the only removal mechanism. Note that the estimate of the cumulative inventory of radionuclides in the Boulder Zone is not performed using results of the radial transport model. While injectate radionuclide activity concentrations are determined on a basis essentially consistent with that used to develop DCD Table 11.2-8 (i.e., based on the release of the average daily discharge for only 292 days per year), it is otherwise conservatively assumed for purposes of the PA that both units operate continuously (i.e., for 365 days per year) throughout the life of the plant and, therefore, continuously release their average daily discharge. This assumption of continuous operation and release is conservative because it increases the radioactive source term, resulting in a higher estimate for the cumulative inventory than would otherwise be obtained.

11.2.3.5.2 Receptor Determination and Dose Analysis

The determination of appropriate members-of-the-public receptors and assessment of the consequential doses which they could potentially receive as a result of the injection of radwaste to the Boulder Zone are described in the paragraphs below. The use of both preliminary and detailed liquid effluent pathway scenario identification and screening analyses in the selection of the

members of the public to be considered and retained for dose analysis purposes is discussed, to include their consideration of the local hydrogeology and consequential potential for vertical effluent migration out of the Boulder Zone as well as current and projected land and water use. The identification and screening process includes a definition of Turkey Point Units 6 & 7 specific liquid effluent exposure pathway modes and associated event scenarios, development of a conceptual model for each such scenario, an assessment of whether a liquid effluent pathway scenario is to be retained for further analysis, and the determination of the consequential doses to the associated member-of-the-public receptors.

11.2.3.5.2.1 Exposure Pathway Modes for Liquid Effluent Pathway Analysis

Two operating modes—normal operation and off-normal operation—and a special case (inadvertent intrusion) are considered for purposes of the member-of-the-public screening analysis.

Normal Operation – Operation within specified operational limits and conditions. This mode assumes that the DIS and subsurface hydrogeological units operate as designed or expected, i.e., with no system failures such as deep injection well seal failure or subsurface confining unit fracture/failure.

Off-Normal Operation – An operational process beyond specified operational limits or conditions that, while not expected, may occur during the operating lifetime of a facility, e.g., a deep injection well seal failure or subsurface confining unit fracture/failure.

Inadvertent Intrusion – This is a special case mode whereby, while highly unexpected, a member of the public is unknowingly exposed to injectate while otherwise engaging in normal activities.

11.2.3.5.2.2 Member-of-the-Public Location Selection Process and Bases

RG 1.109 provides guidance regarding the determination of doses to members of the public as a result of routine releases of reactor effluents. Specifically, RG 1.109 provides guidance related to the selection of member-of-the-public locations. Per RG 1.109, the point of dose evaluation for the liquid effluent pathway analysis is to be the location of the highest offsite dose. It is evaluated:

- *"At a location that is anticipated to be occupied during the operating lifetime of the plant, or*

- *With respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation."*

With regard to the latter evaluation consideration, RG 1.109 states:

…the applicant may take into account any real phenomena or actual exposure conditions. Such conditions could include actual values for agricultural productivity, dietary habits, residence times, dose attenuation by structures, measured environmental transport factors (such as bioaccumulation factors), or similar values actually determined for a specific site.

The above guidance is applied first to identify locations in unrestricted areas beyond the Turkey Point Units 6 & 7 site where liquid effluent pathway exposure to a member of the public might occur. The dose delivered to each identified member of the public is then estimated through the application of the maximum-exposed-individual approach regarding lifestyle and dietary habits as implemented in the NRC-endorsed computer program LADTAP II.

To determine the greatest relevant extent of radionuclide propagation within which potential liquid effluent pathway exposure to a member of the public must be assessed, an initial dose analysis is performed using the LADTAP II computer program to identify the DCD Table 11.2-7 radionuclides that are the most significant potential dose contributors considering the assumed ingestion pathways of drinking water and irrigated milk, meats, and vegetables for effluent decay times ranging from 5 to 100 years. This analysis determined that, while the percentage of each of the radionuclide's contribution to the total dose varies over time due to each of their respective half-lives, tritium, strontium-90, cesium-134, and cesium-137 contribute over 99 percent of the dose to the total body and the organs of a child (the most conservative receptor) after a decay time of 10 years or more. The time-dependent radial extents of tritium, cesium-134, cesium-137, and strontium-90 along with the corresponding concentration in the respective plumes as determined using the radial transport model are illustrated in Figures 11.2-201,11.2-203, 11.2-205, and 11.2-207, respectively. As these figures indicate, the injectate plume is not expected to reach the nearest potential receptor location until more than 10 years after the inception of injection. The distributions of tritium, cesium-134, cesium-137, and strontium-90 in the Boulder Zone at the end of plant operations are depicted in Figures 11.2-202, 11.2-204, 11.2-206, and 11.2-208, respectively, while Figure 11.2-209 provides the time-dependent relative concentration (i.e., simulated concentration, C, divided by the as-injected concentration, C_0) breakthrough curves for all four radionuclides.

To give some context to the actual dose contribution from each radionuclide during the modeled time period, there is a limited duration, i.e., over a decay period of about 30 years or less, in which the sum of the per-unit radionuclide doses is expected to be at least 1 mrem. During this period, tritium contributes more than 90 percent of the total dose (i.e., the contribution to the total body dose for a child from radionuclides other than tritium is a small fraction of a mrem for any period greater than 5 years). Based on the most limiting 10 CFR Part 50, Appendix I, design objective of 3 mrem per year for the total body per unit, or 6 mrem for both units, the tritium concentration yielding this dose to the child (i.e., the 6 mrem derived activity concentration) is determined to be 37,000 pCi/L (two-unit source term and two-unit deep well injection rate; the two-unit case is more limiting as it results in a greater extent of plume expansion at any given point in time as well as a higher cumulative radionuclide inventory).

As an indicative determinant of the area of consequence to this analysis, this 37,000 pCi/L derived tritium activity concentration is then used as a basis for ascertaining the farthest radial extent of a tritium concentration capable of producing doses at the level of the 10 CFR Part 50, Appendix I, design objectives during the modeled timeframe. Figure 11.2-210 depicts the extent of the 37,000 pCi/L tritium activity concentration profile at 5, 10, 25, 50, and 75 years. Tritium concentrations are below the 37,000 pCi/L derived activity concentration at all locations at 100 years and, therefore, no contour is shown in Figure 11.2-210 for this simulation time. As Figure 11.2-210 indicates, the farthest radial extent of the 37,000 pCi/L-derived tritium activity concentration during the modeled time frame is between approximately 1.9 and 2.0 miles from the injection zone. The radial extent of the 37,000 pCi/L tritium activity concentration profile begins to retract after year 25 due to the increasing thickness of the low salinity injectate plume and the resultant increase in the travel time to any given radial distance from the injection point. After injection ceases at year 61, the tritium plume diminishes due to radioactive decay and the lack of continued injection, and as a result, the 37,000 pCi/L tritium activity concentration contour retracts more rapidly toward the injection location.

The locations at which exposure to treated liquid radioactive waste disposed of through deep well injection may potentially occur are assigned to three areas based on their placement relative to Turkey Point Units 6 & 7. These areas, which are illustrated in Figure 11.2-211, are defined as follows:

Plant Area – This area includes the location of Turkey Point Units 6 & 7 and includes the DIS. No current or future member of the public or populations has

access to effluent at this location. Plant workers, however, may have exposure to effluent.

Property Area – This area includes all FPL-owned property between the plant area and the Turkey Point property boundary. No current or future member of the public or populations has access to effluent at this location. Plant workers, however, may have exposure to effluent.

Beyond Property Area – This area includes the area beyond the Turkey Point property boundary. Members of the public and populations who are part of the general public may access effluent at these locations. The land ownership in this area includes private, government, and significant FPL ownership (Figure 11.2-212).

11.2.3.5.2.3 Liquid Effluent Pathway Screening Analysis

11.2.3.5.2.3.1 Scenario Identification

An initial liquid effluent pathway screening analysis is conducted to identify potential scenarios under which members of the public could possibly be exposed to the liquid effluent and to then categorize them by location (plant area, property area, beyond property area) and mode (normal, off-normal, inadvertent intrusion). An analysis is then performed to determine if a scenario is retained for detailed liquid effluent pathway analysis or, alternatively, eliminated from further consideration. This screening analysis is described in the paragraphs below. Those scenarios that are retained for further analysis along with the determination of the resultant doses are described in greater detail in the subsequent sections.

11.2.3.5.2.3.1.1 Plant Area

Normal Operation

The normal operation mode for purposes of potential member-of-the-public exposure scenario determination assumes that no such system failures as injection well failure or subsurface loss of confinement occur within the bounds of the plant area or elsewhere. As part of the normal operation of the DIS, it is anticipated that some vertical migration of the effluent will occur from the Boulder Zone into the middle confining unit, primarily as a result of injection pressure and buoyancy. Based on the vertical transport modeling results discussed in Subsection 11.2.3.5.1.1.2, this upward migration of effluent is expected to be contained below a depth of 2600 feet, or approximately 300 feet into the middle confining unit, at the end of the 100-year simulation duration. Given that the top of

the middle confining unit is at approximately 1200 feet below ground surface (bgs) (References 214 and 217), the plume would have to vertically migrate an additional 1000 feet or more to reach the Upper Floridan aquifer. The time to transit this additional distance and reach the Upper Floridan aquifer is expected to be greater than 100 years under this Normal Operation scenario (i.e., no unanticipated vertical flow conduit is encountered in the middle confining unit), by which time radionuclide concentrations are expected to have fallen to non-consequential levels even if only radioactive decay is taken into consideration. Because the Upper Floridan aquifer is, therefore, not anticipated to be impacted, no member-of-the-public exposure pathway is possible, and this scenario is not retained for further liquid effluent pathway analysis.

Off-Normal Operation

Middle Confining Unit Failure

Geological, seismological, and geophysical investigations performed for the site (Subsection 2.5.3) as well as geologic results from EW-1 (Reference 214) indicate there are no known or suspected faults or other geological features at the Turkey Point Units 6 & 7 site that would allow vertical fluid movement through the middle confining layer. The borehole compensated sonic geophysical log performed on the interval from 1475 feet below pad level to 3230 feet below pad level of EW-1 was reviewed for evidence of a fracture(s) within the logged interval. Based on this data (Reference 214), no features are observed in EW-1 suggesting that the confining strata above the Boulder Zone has been compromised by vertical fractures or other features. However, a failure in the lower confining unit above the Boulder Zone within the bounds of the plant area, should one occur, could cause a “U-Tube” type scenario where Boulder Zone water containing effluent travels vertically through an improperly abandoned well, naturally formed conduit, etc. This effluent could conceivably travel laterally through the Upper Floridan aquifer to beyond property area locations to potentially be accessed by members of the public/populations for use (e.g., in plant nurseries). However, the potential radiological impacts of this scenario are bounded by those of the beyond property area—off-normal operation middle confining unit failure—related scenario described below. Specifically, in being transported to a potential beyond property area member-of-the-public receptor location, the effluent would undergo dilution and dispersion in the Upper Floridan aquifer and the eastward gradient in the Upper Floridan aquifer (Reference 208) would tend to impede the flow of the effluent plume inland toward the beyond property area location (illustrated as Pathway B in Figure 11.2-213). Further, as part of the prompt detection and mitigative strategies program prepared for DIS off-normal operations, monitoring

of the Upper Floridan aquifer and dual-zone monitoring well conditions is to be conducted to alert plant operators of possible effluent incursions into the Upper Floridan aquifer. Response actions are to include, as appropriate, confirmatory Upper Floridan aquifer/dual-zone well monitoring, removal of affected DIS components from service, and other actions protective of members of the public and plant workers. The DIS off-normal operations prompt detection and mitigative strategies program will be part of the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM)/Radiological Environmental Monitoring Program (REMP) to be made available for inspection prior to fuel load (Table 13.4-201). This scenario is, therefore, not considered a feasible Off-Normal Operation scenario and is not retained for further liquid effluent pathway analysis.

Worker Exposure at Leaking Pipe

A section of the deep injection well piping is anticipated to be located above grade. There is a possibility that a temporary leak could occur in this piping, resulting in a localized release of effluent. However, any consequential plant worker exposure is suitably controlled through the appropriate implementation of the plant's occupational radiation control program as described in Appendix 12AA in applying engineering controls, ALARA practices, and other exposure avoidance/reduction measures to maintain each radiation worker's resultant dose below the applicable annual occupational limit of 5 rem. Additionally, since positive access control of the plant area is maintained, there is no potential for member-of-the-public exposure. Therefore, this scenario is not retained for further liquid effluent pathway analysis.

Worker Exposure to Biscayne Aquifer

The exposure pathway is a worker at the site who may be exposed to effluent from the Biscayne aquifer during any type of earthmoving work (e.g., trenching) that may be conducted over the operational lifetime of Turkey Point Units 6 & 7. Normal operation assumes some limited vertical migration of effluent into the middle confining unit above the Boulder Zone, but as described above, it is expected to be contained well below the top of the middle confining unit over the plant's operational lifetime and beyond. This scenario, however, assumes vertical migration of effluent through both the middle and the intermediate confining units into the Biscayne aquifer and discounts the dispersion and dilution that will occur in the intervening Upper Floridan aquifer. Therefore, this scenario is not considered feasible and is not retained for further liquid effluent pathway analysis.

Deep Injection Well Failure at Site

This scenario involves a subsurface mechanical failure of one or more deep injection wells that is undetected by plant operators, resulting in the injection of effluent into the Upper Floridan or Biscayne aquifers. This scenario is not considered feasible for the following reasons:

- The construction materials, installation, and testing for the deep injection wells are both rigorous and thorough (Subsection 9.2.12)
- Pressure and flow into the deep injection wells are continuously monitored for fluctuations, which could indicate a well failure

Middle Confining Unit Failure and Injectate Travel to the Unit 5 Upper Floridan Water Supply Wells

This scenario assumes travel of injectate through a fracture in the middle confining unit and travel to one or more of the Unit 5 water supply wells, which are screened in the Upper Floridan aquifer. As discussed above, geological, seismological, and geophysical investigations performed for the site (Subsection 2.5.3) as well as geologic results from EW-1 (Reference 214) indicate there are no known or suspected faults or other geological features at the Turkey Point Units 6 & 7 site that would allow vertical fluid movement through the middle confining layer. As also discussed above, monitoring of Upper Floridan aquifer and dual-zone monitoring well conditions is to be conducted to alert plant operators of possible injectate incursions to the Upper Floridan aquifer. Response actions are to include, as appropriate, confirmatory Upper Floridan aquifer/dual-zone well monitoring, removal of affected DIS components from service, and other actions protective of members of the public and plant workers. The DIS off-normal operations prompt detection and mitigative strategies program will be part of the Turkey Point Units 6 & 7 ODCM/REMP to be made available for inspection prior to fuel load (Table 13.4-201).

This scenario, therefore, is not considered feasible and is not retained for further liquid effluent pathway analysis.

Inadvertent Intrusion

No inadvertent intrusion scenarios relating to exposure and subsequent dose from the operation of the DIS are identified at the plant area since positive access control is maintained.

11.2.3.5.2.3.1.2 Property Area

Normal Operation

As described in the *Plant Area — Normal Operation* discussion above, the normal operation mode for purposes of potential member-of-the-public exposure scenario determination assumes no system failures, e.g., injection well failure or subsurface loss of confinement, within the bounds of the property area. As part of the normal operation of the DIS, there is expected to be some limited vertical migration of the effluent from the Boulder Zone into the middle confining unit. However, as further described in the *Plant Area — Normal Operation* scenario above, because the Upper Floridan aquifer is not anticipated to be impacted, no member-of-the-public exposure pathway is expected, and this scenario is not retained for further liquid effluent pathway analysis.

Off-Normal Operation

Middle Confining Unit Failure

As previously discussed, a failure in the middle confining unit above the Boulder Zone within the bounds of the property area, should one occur, could create a “U-Tube”-type scenario where Boulder Zone water could be introduced into the Upper Floridan aquifer to potentially be accessed by beyond property area members of the public/populations for use. However, as also discussed above, such a failure within the property area is unlikely, the effluent would undergo dilution and dispersion in the Upper Floridan aquifer in being transported to a potential beyond property area member-of-the-public receptor location, and the eastward gradient in the Upper Floridan aquifer (Reference 208) would tend to impede the flow of the effluent plume inland toward the beyond property area location (illustrated as Pathway B in Figure 11.2-213). Therefore, this scenario is not considered a feasible off-normal operation scenario and is not retained for further liquid effluent pathway analysis.

Migration of Effluent Through the Middle and Intermediate Confining Units

The potential exposure pathway is a member of the public who may be exposed to surface water that is in connection with the Biscayne aquifer. This scenario is similar to the worker exposure to Biscayne aquifer scenario discussed above as it also assumes the vertical migration of effluent through both the middle and the intermediate confining units into the Biscayne aquifer. However, as further described in the previously discussed *Plant Area — Normal Operation* scenario, any upward migration of effluent is expected to be contained well below the top of

the middle confining unit over the plant's operational lifetime and beyond, and thus, it is not anticipated that any radionuclides will travel through the middle confining unit absent some failure in that stratum. This scenario, however, requires the postulation of a failure in the intermediate confining unit as well as the middle confining unit in order for the effluent to enter into the Biscayne aquifer and discounts the dilution and dispersion that will occur in the intervening Upper Floridan aquifer. Therefore, this scenario is not considered feasible and is not retained for further liquid effluent pathway analysis.

Inadvertent Intrusion

No inadvertent intrusion scenarios relating to exposure and subsequent dose from the operation of the DIS have been identified at the property area since positive access control is maintained.

11.2.3.5.2.3.1.3 Beyond Property Area

Normal Operation

As described in the *Plant Area — Normal Operation* discussion above, the normal operation mode for purposes of potential member-of-the-public exposure scenario determination assumes that no systems failures, e.g., injection well failure or subsurface loss of confinement, occur beyond the property area. As part of the normal operation of the DIS, there is expected to be some limited vertical migration of the effluent from the Boulder Zone into the middle confining unit. However, as further described in the *Plant Area — Normal Operation* scenario above, because the Upper Floridan aquifer is not anticipated to be impacted, no member-of-the-public exposure pathway is expected, and this scenario is not retained for further liquid effluent pathway analysis.

Off-Normal Operation

Migration of Effluent Through the Middle and Intermediate Confining Units

The potential exposure pathway is a member of the public who may become exposed to effluent that is in connection with the Biscayne aquifer. This scenario is similar to the *Plant Area — Worker Exposure* to Biscayne aquifer scenario discussed above because it also assumes the vertical migration of effluent through both the middle and the intermediate confining units into the Biscayne aquifer. This aquifer could then potentially be accessed by a member of the public or population for potable water use, farming, etc. However, as further described in the *Plant Area — Normal Operation* scenario above, any upward migration of

effluent is expected to be contained well below the top of the middle confining unit over the plant's operational lifetime and beyond, and thus, it is not anticipated that any radionuclides will travel through the middle confining unit absent some failure in that stratum. This scenario, however, requires the postulation of a failure in the intermediate confining unit as well as the middle confining unit in order for the effluent to enter the Biscayne aquifer and discounts the dilution and dispersion that will occur in the intervening Upper Floridan aquifer. Therefore, this scenario is not considered feasible and is not retained for further liquid effluent pathway analysis.

Middle Confining Unit Failure

A failure in the middle confining unit above the Boulder Zone could create a "U-Tube"-type scenario where Boulder Zone injectate containing effluent travels vertically up into the Upper Floridan aquifer through an improperly abandoned well, naturally formed conduit, etc., at a location where it could potentially be accessed by a member of the public/populations for use (e.g., in plant nurseries). This scenario is considered feasible and is retained for further liquid effluent pathway analysis.

Inadvertent Intrusion

A member of the public located at or near the property boundary could drill a water supply well directly into the Boulder Zone and use its groundwater for ingestion, irrigation, and livestock. While possible, this scenario is highly improbable given the Boulder Zone's extreme depth, high TDS concentration, and classification by the Florida Department of Environmental Protection (FDEP) as a Class G-IV aquifer not suitable for potable use and not subject to the minimum groundwater criteria. (See rules 62-520.410 and 62-520.440, Florida Administrative Code.) A more plausible scenario is for a member of the public to drill a well into the Upper Floridan aquifer immediately above a failure in the middle confining unit (illustrated as Pathway A in Figure 11.2-213) and to then unknowingly use the contaminated Upper Floridan groundwater for both drinking water ingestion and subsistence irrigation. This hypothetical scenario is, therefore, retained for further dose consideration to represent the maximum exposed member of the public.

11.2.3.5.2.3.2 Summary of Scenarios Retained for Further Liquid Effluent Pathway Analysis

Table 11.2-205 summarizes the scenarios retained for further detailed consideration (as indicated by shading). The members of the public are listed where they have been identified.

11.2.3.5.2.4 Detailed Liquid Effluent Pathway Analysis and Member-of-the-Public Determination

A more detailed analysis of the liquid effluent pathway scenarios considered feasible following completion of the initial screening analysis is performed to determine which liquid pathway effluent scenarios (location and mode) potentially constituting exposure to the MEI are to be used for detailed dose analysis purposes. As part of this analysis, current and projected land and water usage in the vicinity of Turkey Point are taken into consideration in selecting member-of-the-public location(s) at and beyond the property boundary and the associated members of the public/populations that may potentially be impacted. A description of this current and projected land and water usage is provided below followed by a discussion of the detailed liquid effluent pathway analysis and its results.

11.2.3.5.2.4.1 Land Ownership/Water Use in Areas Beyond the Property Boundary

To identify opportunities where members of the public could potentially be exposed to injectate at points beyond the property boundary (Figure 11.2-211), an examination of current and projected land use/ownership and groundwater use in the vicinity of Turkey Point is conducted. This examination provides the rationale both for eliminating, if possible, previously retained off-normal scenarios from further consideration and for selecting the associated member-of-the-public locations and exposure pathways (e.g., ingestion, irrigation) for those scenarios that are retained. (Note: all normal operation scenarios have already been eliminated from further consideration.)

Figure 11.2-212 depicts the available information related to current land ownership and water supply well location and type. For reference, the maximum areal extent in which a tritium activity concentration at or above the 37,000 pCi/L derived activity concentration might exist is also depicted. The following paragraphs summarize current and projected land/water use in the area of Turkey Point based on data obtained from several sources, including South Florida Water Management District (SFWMD), county, and local municipal planning documents (References 218 through 223) and discuss the consequential implications with regard to the identification of the beyond property area members of the public. This information will be verified during the annual land use census required by the Turkey Point Units 6 & 7 ODCM. Changes to the liquid effluent pathway analysis as a result of the land use census will be incorporated in an ODCM and/or ODCM-implementing procedure revision.

The land parcels immediately adjacent to the west of the property area consist of agriculture land that is owned predominantly by FPL, Miami-Dade County, SFWMD, as well as other private entities or individuals (Figure 11.2-212). Land parcels owned by private entities or individuals are within an area of agricultural use, and based on aerial photography, only a few houses are located on these parcels to the west. The land parcels immediately adjacent to the north of the property area are categorized as parks and recreation land use, environmental protected parks land use, undeveloped land, or agriculture use. FPL, SFWMD, and Miami-Dade County are the predominant land owners in this area. There are land parcels owned by private entities and individuals, with the nearest privately owned parcel to the property boundary being located 2.2 miles from the effluent injection point (Figure 11.2-214), but these parcels are also designated for nonresidential use. Based on current land use records and aerial photography, no large scale or individual subsistence farming is currently occurring near Turkey Point. Current land use near Turkey Point does not include large-scale farming or livestock raising that could potentially impact the population through the ingestion of food products.

Future land use near Turkey Point will be influenced by planning and policies enacted by Miami-Dade County as well as state and federal agencies. Areas designated as resources of regional significance and wetlands on federal, state, or county land acquisition lists have been given a high priority for public acquisition. Additionally, lands may be acquired as part of the Comprehensive Everglades Restoration Plan projects in the area. Urban sprawl is to be discouraged by not providing new water supply or wastewater collection service to land within areas designated agriculture, open land, or environmental protection. Potentially, all land near Turkey Point is to be removed from private ownership and designated as public protected land during the operational lifetime of Turkey Point Units 6 & 7. More importantly, the projected future land use in the beyond property area will not be enabling of large-scale farming or livestock raising that could potentially impact the population through the ingestion of food products.

Current water use indicates that there are no current public users of any groundwater in the immediate vicinity of the property area (Figure 11.2-212). There are only three current users of the Upper Floridan aquifer within Miami-Dade County (Table 11.2-206), all of whom are located significantly beyond the maximum extent of the 37,000 pCi/L derived tritium activity concentration contours. Future water use policy mandates that individual potable water supplies, including private wells, are to be considered interim facilities to be used only where no alternative public water supply is available and land use and water

resources are suitable for an interim water supply. Such interim water supply systems are to be phased out as service becomes available from municipal or county supply.

Miami-Dade County future water use planning includes development of new potable water well fields and alternative water supplies to plan for the county's existing and future water supply needs. After 2013, Miami-Dade County plans to meet all water supply demands associated with new growth from alternative water supply sources, which may include withdrawals from the Floridan aquifer. However, the planned points of withdrawal for these potential additional sources of water are located 10 miles or more from the Turkey Point Units 6 & 7 site.

Current and future land and water use in the beyond property area impacts the selection of members of the public/populations who could be exposed to the DIS effluent. These populations could be impacted through the use of groundwater and through the ingestion of animals and crops exposed to this same groundwater. Current and future land use in the area would indicate that large scale farming or livestock production is not expected. Although several municipalities may in the future use such additional groundwater resources as water from the Upper Floridan aquifer, these potential well fields would be located significantly beyond the maximum extent of the 37,000 pCi/L derived tritium activity concentration contours. Based on current and projected future land and water use policy and trends as described above, population exposure to effluent is not anticipated.

11.2.3.5.2.4.2 Retained Liquid Effluent Pathway Scenarios, Member-of-the-Public Identification, and Selection of Locations for Dose Analyses

As noted above, potential member-of-the-public exposure is influenced by current land/water use and future land and water use policy and trends (References 218 through 223). Individual ownership of beyond property area land in the vicinity of Turkey Point is limited and future land use planning would indicate that individual ownership in this area will only decrease. Additionally, there is no current subsistence farming or the raising of livestock in the area; based on future planning and trends, this is expected to remain the case throughout the operational life of Turkey Point Units 6 & 7. There are no current individual users of groundwater from any aquifer either within or in the vicinity of the maximum extent of the 37,000 pCi/L derived tritium activity concentration contours. Future water use planning would discourage long-term groundwater use in favor of water provided by municipalities drawing on water sources at points significantly beyond

the maximum extent of the 37,000 pCi/L derived tritium activity concentration contours.

Although the likelihood of individual land ownership and groundwater use in the vicinity of the Turkey Point Units 6 &7 site is low, radiological exposure to members of the public as a consequence of underground injection of effluent is a possibility, albeit remote, particularly within an extended timeframe (e.g., 100 years) as influenced by such factors as changes in public policy, climate, or population trends. Therefore, to bound this uncertainty, member-of-the-public locations have been selected based on their placement relative to the property area. Specific event scenarios potentially involving members of the public sited at these locations have been categorized as follows:

- Credible – Such a scenario may be expected to occur during the operational lifetime of the plant (or beyond).

- Non-Credible – Such a scenario is not likely to occur during the operational lifetime of the plant or beyond; however, it is included to provide a bounding dose for the off-normal event category.

The only current users of water from the Upper Floridan aquifer in the vicinity of Turkey Point are located at the Ocean Reef Club community, approximately 7.7 miles southeast of the Turkey Point Units 6 & 7 site (Figure 11.2-214). Although the current use of this water is for landscape irrigation, potable water use could occur at this location. Therefore, such use by the Ocean Reef Club community is retained as a credible beyond property boundary member-of-the-public exposure scenario.

As described previously, there are no members of the public currently resident within or near the maximum extent of the 37,000 pCi/L derived tritium activity concentration contours. Although sustained individual production of livestock and garden products through subsistence farming and associated groundwater ingestion in the beyond property area is not anticipated during the operational life of Turkey Point Units 6 & 7, short-term groundwater use and ingestion of groundwater potentially containing effluent is a possibility. Therefore, access and use of such groundwater in the beyond property area by a member of the public, while classified as non-credible, is retained for further liquid effluent pathway analysis.

All potentially exposed individuals other than those in the Ocean Reef Club community are placed at the location of the nearest privately owned land parcel to

the property boundary, located 2.2 miles from the effluent injection point (Figure 11.2-214), as this constitutes the nearest beyond property area location that could potentially serve as an exposure point for a member of the public. The "U-tube" or conduit constituting failure of the middle confining unit is assumed to occur beneath this land parcel, since as discussed above, the eastward gradient in the Upper Floridan aquifer would cause the effluent introduced by a failure occurring closer to the effluent injection point to flow away from the member of the public's location (Figure 11.2-213). The effluent-containing water is then assumed to instantaneously travel to the Upper Floridan aquifer, where it is then available for access by a member of the public. It is assumed that a production well is placed exactly over the middle confining unit failure; dilution in the Upper Floridan aquifer is, therefore, not considered. Furthermore, no credit is taken for travel time from the Boulder Zone through the middle confining unit to the Upper Floridan aquifer.

The consequential scenarios retained for dose analysis purposes are summarized below.

Plant Area

Normal Operation – None retained

Off-Normal Operation – None retained

Inadvertent Intrusion – Not applicable

Property Area

Normal Operation – None retained

Off-Normal Operation – None retained

Inadvertent Intrusion – Not applicable

Beyond Property Area

Normal Operation – None retained

Off-Normal Operation

- Middle confining unit failure located 2.2 miles from the modeled effluent injection point and member-of-the-public Upper Floridan aquifer use resulting in exposure through drinking water ingestion (non-credible)

- Middle confining unit failure and individual member-of-the-public Upper Floridan aquifer use at Ocean Reef community for drinking water only (credible)

Inadvertent Intrusion

- Member-of-the-public drilling a well into the Upper Floridan aquifer immediately above a failure in the middle confining unit located 2.2 miles from the effluent injection point and then unknowingly using the contaminated Upper Floridan groundwater thereby made available for drinking water ingestion, irrigation, milk animals, and livestock (subsistence driller)

Table 11.2-207 provides a summary of the scenarios retained for detailed dose analysis purposes, including the location of the members of the public. Figure 11.2-214 depicts the location of the members of the public. Specific source terms, methods/pathways of exposure, etc., are summarized in the next section.

11.2.3.5.2.5 Dose Analyses

The doses allocated to the retained members of the public are based on the source term, exposure duration, exposure pathways, etc. established by the associated scenarios. The dose analyses are summarized in the following paragraphs.

11.2.3.5.2.5.1 Beyond Property Area – Off-Normal Operation

Middle Confining Unit Failure and Member-of–the-Public Exposure (Credible)

The Ocean Reef Club community, as depicted on Figure 11.2-214, is approximately 7.7 miles from the effluent injection point. As summarized in Table 11.2-206, this community represents the nearest members of the public in the near vicinity of the Turkey Point Units 6 & 7 site to currently use Upper Floridan aquifer water for any application. While Upper Floridan aquifer water is currently only being used by Ocean Reef Club for irrigation purposes, the most credible off-normal receptor was identified as a member of the public in the Ocean Reef Club community. This scenario assumes the water supply well is directly over the middle confining unit failure and takes no credit for further dilution, resulting in the same radionuclide concentrations in the Upper Floridan aquifer as are observed in the Boulder Zone. Based on the radial transport model's simulation results, the Boulder Zone groundwater radionuclide concentration at this location for all radionuclides of interest is expected to remain at non-

consequential levels for the full 100-year simulation duration. Therefore, no dose has been calculated.

Middle Confining Unit Failure and Member-of-the Public-Exposure (Non-Credible)

The nearest privately owned land parcel to the property boundary, which is located 2.2 miles from the centroid of the DIS, has been selected as the location for the non-credible member of the public (Figure 11.2-215). It is assumed that a production well is directly connected to a conduit or other failure in the middle confining unit occurring at this location such that no mixing occurs in the Upper Floridan aquifer. The member of the public is assumed to use the Upper Floridan aquifer water for drinking water ingestion only.

The expected radionuclide concentrations are evaluated at this location. Figure 11.2-209 presents the tritium, cesium-134, cesium-137, and strontium-90 relative concentration profiles at this location over the 100-year simulation duration, as calculated by the radial transport model. As discussed under *Radioactive Source Term Selection* in Subsection 11.2.3.5.1.1.1, these are the radionuclides that have been retained for fate and transport modeling and subsequent dose analysis. The maximum radionuclide concentrations and corresponding times of occurrence following start of plant operation are as follows, based on two units:

tritium:	3.1E04 pCi/L (25 years)
cesium-134:	7.7E-03 pCi/L (15 years)
cesium-137:	7.6E-01 pCi/L (42 years)
strontium-90:	5.6E-04 pCi/L (41 years)

The above concentrations are based on a 1-year interval between the startup of Units 6 and 7 and a projected 60 years of continuous operation per unit.

These maximum concentrations are conservatively assumed to occur concurrently and, therefore, are used collectively as the source term for the dose analyses conducted for this location. For these further analyses, a separate LADTAP II run is made for each radionuclide (tritium, strontium-90, cesium-134, and cesium-137) to calculate the dose to an offsite receptor 2.2 miles from the modeled effluent injection point. In LADTAP II, doses are calculated based on the above concentrations for two units. Doses per unit are obtained by dividing the doses calculated by LADTAP II by two.

For tritium, as an example, the LADTAP II input parameters are as follows:

- Discharge to impoundment per unit = 6230 gpm = 3.40E07 L/day
- Annual release per unit = 1.3E03 Ci/yr
- LADTAP II transit (decay) time = 21 years

The annual release per unit is calculated as follows:

- Injectate concentration = 1.0E05 pCi/L as given on Table 11.2-201

- Annual release per unit = (1.0E05 pCi/L)(3.40E07 L/day)(365 day/yr) (Ci/1E12 pCi) = 1.3E03 Ci/yr

Note that this annual release value exceeds the corresponding DCD Table 11.2-7 value by a factor of 1.25. This reflects the impact of having determined the plant-specific injectate concentrations on a basis consistent with that used to develop DCD Table 11.2-8, i.e., based on the release of the average daily discharge for only 292 days per year, while otherwise conservatively assuming that both units operate continuously (i.e., for 365 days per year throughout the life of the plant) and, therefore, continuously release their average daily discharge. It must be emphasized that these are simplifying assumptions made solely for the purposes of performing a conservatively bounding analysis and that, in making these assumptions, there is no intent to convey that the plant is expected to actually be operated in a way that is different from the certified design.

LADTAP II uses the transit time parameter to calculate the effective decayed radionuclide activity concentration at the receptor location. To assign transit time values, a two-step approach is necessary. First, as further described above, a radial transport model is used to determine activity concentrations at the receptor location that account for advection, dispersion, buoyancy effects, and chemical processes that include first-order radioactive decay. For tritium, the calculated peak concentration at the offsite receptor is 3.1E04 pCi/L based on the injection concentration of 1.0E05 pCi/L and the dilution flow of 6230 gpm per unit.

Second, the LADTAP II transit time input parameter value is determined by calculating the duration that would be required for the as-injected tritium activity concentration of 1.0E05 pCi/L to decay to this peak concentration at the receptor location of 3.1E04 pCi/L as predicted by radial transport model. This duration, i.e., the transit time value, is solved for using a variation of the general equation for radioactive decay:

$$C_{rec} = C_{inj}\, e^{-\lambda t}$$

$t = [\ln(C_{inj}/C_{rec})][t_{1/2}/\ln(2)]$
$t = [\ln(1.0E05/3.1E04)][12.33/0.693]$
$t = 21$ years

In this tritium example, C_{inj} and C_{rec} are the tritium activity concentrations at the injection and receptor locations, respectively; λ is the tritium decay constant, defined as ln(2) divided by the tritium half-life, $t_{1/2}$, of 12.33 yr; and t is the decay time, i.e., the value of the LADTAP II transit time input parameter to be solved for.

Based on this and the other required inputs as noted above, LADTAP II calculates the doses to the offsite receptor corresponding to a peak tritium activity concentration of 3.1E04 pCi/L. Source terms, peak activity concentrations, and receptor doses for the other three radionuclides retained for further analysis are similarly calculated.

Table 11.2-208 summarizes the resultant doses to the MEI (for conservatism, a child was considered as the member of the public). The total body dose is lower than the 10 CFR Part 50, Appendix I, annual design objective of 6 mrem for two units. The organ dose (dose to child's liver as maximum organ) is lower than the 10 CFR Part 50, Appendix I, annual design objective of 20 mrem for two units. As can be seen, tritium is the dominant dose contributor. Cost-benefit analysis of population doses is presented in Subsection 11.2.3.5.2.5.2.

11.2.3.5.2.5.2 Beyond Property Area – Inadvertent Intrusion

The doses associated with the inadvertent intrusion scenario represent a non-credible worst-case bounding estimate for annual dose. As previously described, farming and the raising of milk animals and livestock are not currently performed and are not anticipated to be performed in the region adjacent to Turkey Point. However, to present this worst-case dose, a subsistence driller is assumed exposed through these pathways as well as through effluent ingestion subsequent to the inhalation, immersion, and deposition exposure that occurs during the actual drilling operations. This scenario assumes that a water supply well is installed in the Upper Floridan aquifer directly above the conduit in the middle confining unit at the 2.2-mile location that allows deep well injectate to instantaneously travel to the Upper Floridan aquifer from the Boulder Zone. Therefore, the location as well as the radionuclide concentrations for this member of the public are the same as those for the beyond property area – off-normal operation non-credible member of the public, as previously described.

Doses to the total body and maximum organ (liver) due to inhalation, immersion, and deposition acquired during the drilling activity by the member-of-the-public age group receiving the maximum doses are first calculated. For purposes of this calculation, the total duration of exposure during drilling operations is determined as follows:

- A water supply well in the Upper Floridan aquifer typically requires 75 days to complete. The Upper Floridan aquifer, which is assumed to contain the radionuclides, is not encountered until 1000 feet have been completed (or 66 percent of the 75 days). Therefore, exposure due to drilling is assumed to be for 25 days.

- The time to complete and develop a water supply well in the Upper Floridan aquifer is 20 days. Exposure is assumed to occur during this entire time period.

Therefore, the exposure time for the driller is 45 days total. A 12-hour shift is assumed for each day.

These doses are then conservatively combined with the annual doses to the maximum dose age group from ingestion of drinking water and irrigated foods to arrive at the total annual doses for the subsistence driller. The LADTAP II computer program is used to calculate doses to the member of the public from ingestion of drinking water, milk, meats, and vegetables irrigated with Upper Floridan groundwater. Drilling-related doses to the total body and maximum organ (liver) due to inhalation, immersion, and deposition are determined using the appropriate RG 1.109 methodology, with the exception that immersion-related dose conversion factors are obtained from Federal Guidance Report No. 12 (Reference 224).

To determine the inhalation and immersion pathway doses resulting from a driller standing in an evaporating puddle of liquid effluent brought to the surface by the drilling operations, the resultant concentration of radionuclides in the air must first be determined. Because RG 1.109 does not provide guidance on establishing airborne activity concentrations due to puddle evaporation, an empirical relationship for determining puddle evaporation rates developed by the EPA is used (Reference 225). In all cases, values for the various parameters used in determining the doses due to inhalation, immersion, and deposition are conservatively selected. For further conservatism, the as-calculated doses due to these exposure pathways are then doubled before being combined with the

annual doses from ingestion of drinking water and irrigated foods to arrive at the total annual doses for the subsistence driller.

Table 11.2-209 summarizes the resultant doses to the subsistence driller (the maximum dose age group for drilling-related doses is the teen, while for conservatism, a child was considered as the member of the public for purposes of determining the ingestion-related doses). The member of the public's total body and total organ doses are both determined to be lower than the associated 10 CFR Part 50, Appendix I, annual design objectives of 3 mrem and 10 mrem, respectively, for a single unit. Table 11.2-210 summarizes the doses for all retained scenarios.

Although FPL will use a non-traditional disposal method which will serve to isolate the liquid radioactive waste, as indicated in 10 CFR 50, Appendix I, Section II.D, a cost-benefit analysis is required to determine whether radwaste system augments can yield reductions in the 50-mile population doses at a cost of less than $1000 per person-rem. In estimating the potential 50-mile population dose, the maximally exposed individual (MEI) doses in the inadvertent intrusion scenario provided in Table 11.2-209 were selected because they bound those due to off-normal operation as shown in Table 11.2-208. Table 11.2-209 indicates that the annual doses to the MEI due to the ingestion of water and irrigated foods are 2.7 mrem to the total body and 3.8 mrem to the liver per unit, the organ receiving the maximum dose. While these doses are based on consumption rates for the MEI, it is conservatively assumed that the average member of the population also receives these doses.

Of the liquid radwaste system augments listed in RG 1.110, the one with the lowest annual cost (and thus the first potentially justifiable augment based on an averted dose consideration) is a 20-gpm cartridge filter at $11,140. To be justified for installation, this augment would need to avert at least 11.14 person-rem in a 50-mile population ($11,400 divided by $1000 per person-rem averted). Although 10 CFR 50, Appendix I indicates that the thyroid is the only organ to be considered in the cost-benefit analysis, it is conservatively assumed that the bounding organ dose provided in Table 11.2-209 applies to the thyroid. Dividing 11.14 person-rem by the MEI doses of 0.0027 rem to the total body and 0.0038 rem to the organ yields populations of 4125 and 2931 persons, respectively. Accordingly, the minimum 50-mile population justifying installation of the cartridge filter augment is 2931 persons. Consistent with the intruder exposure analysis, each member of this exposed population (cohort) would need to obtain all of their water from a well located 2.2 miles from Units 6 & 7. Due to regulatory constraints and the quality of water in the Boulder Zone, the postulated

inadvertent intrusion scenario is not considered reasonable given that the cohort population would need to ingest water and irrigated foods produced from the postulated well on privately-owned land.

11.2.3.5.3 DIS Performance Monitoring

The dual-zone monitoring wells serve as the primary points for system performance monitoring. Based on the member-of-the-public PA described above, additional offsite monitoring is not proposed. Baseline and operational groundwater radiochemical monitoring is performed at these sampling points. This monitoring includes gross beta, gamma isotopic, and tritium, which will be initially sampled monthly. This frequency will be reduced to quarterly once the underground injection system operational testing phase is complete.

Continuous injection rate and injection pressure monitoring is performed at each deep injection well. Continuous monitoring of water level in each dual-zone monitoring well is also performed. The data is transmitted to each control room where it is continuously monitored.

The proposed monitoring described is applicable to the plant site. Additional offsite sampling, based on exposure pathways and annual land use census results, is performed as necessary during plant operation. This groundwater sampling is taken where Upper Floridan water is used for ingestion or irrigation purposes within the region of Turkey Point. In addition to the land use census, local well permits, as issued by FDEP, are monitored to ensure that the exposure pathways are current. The Turkey Point Units 6 & 7 ODCM documents the exposure pathways, land and water use census, and exposure pathway updates, if necessary. The results of the sampling are reported in the annual radiological operating report. As part of the prompt detection and mitigative strategies program prepared for DIS off-normal operations, monitoring of the Upper Floridan aquifer and dual-zone monitoring well conditions are conducted to alert plant operators of possible injectate incursions to the Upper Floridan aquifer. Response actions include, as appropriate, confirmatory Upper Floridan aquifer/dual-zone monitoring well monitoring, removal of affected DIS components from service, and other actions protective of members of the public and plant workers. The DIS off-normal operations prompt detection and mitigative strategies program are part of the Turkey Point Units 6 & 7 ODCM/REMP to be made available for inspection prior to fuel load. (Table 13.4-201)

11.2.3.6 Quality Assurance

Add the following to the end of DCD Subsection 11.2.3.6:

STD SUP 11.2-1 Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation and testing provisions of the liquid radwaste system is established by procedures that complies with the guidance presented in RG 1.143.

PTN SUP 11.2-2 The quality assurance program for design, construction, procurement, materials, welding, fabrication, inspection and testing activities conforms to the quality control provisions of the codes and standards recommended in Table 1 of RG 1.143.

11.2.5 COMBINED LICENSE INFORMATION

11.2.5.1 Liquid Radwaste Processing by Mobile Equipment

STD COL 11.2-1 This COL Item is addressed in Subsection 11.2.1.2.5.2.

11.2.5.2 Cost Benefit Analysis of Population Doses

PTN COL 11.2-2 This COL item is addressed in Subsection 11.2.3.5.2.5.2.

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224. U.S. Environmental Protection Agency, *External Exposure to Radionuclides in Air, Water and Soil*, Federal Guidance Report No. 12, EPA 402-R-93-081, September 1993.

225. U.S. Environmental Protection Agency, *Risk Management Program Guidance for Offsite Consequence Analysis*, EPA 550-B-99-009, March 2009.

Table 11.2-201
Injectate Concentrations

Component	Half-life (yrs)[a]	Annual Releases (Ci/year)[b]	Injectate Water Concentration (reclaimed water source)	Injectate Water Concentration (saltwater source)
TDS	Not applicable	Not applicable	2.7 kg/m^3	57.0 kg/m^3
H-3	12.4	1.01E3	1.0E5 pCi/L	2.2E4 pCi/L
Cs-134	2.1	9.93E-3	1.0E0 pCi/L	2.1E-1 pCi/L
Cs-137	30.1	1.332E-2	1.3E0 pCi/L	2.9E-1 pCi/L
Sr-90	29.0	1.0E-5	1.0E-3 pCi/L	2.2E-4 pCi/L

(a) Reference 201
(b) Source: DCD Table 11.2-7 (based on 292 days per year operation)

Table 11.2-202
Model Parameter Summary

Parameter	Value
Transmissivity	23,223 m^2/day (250,000 ft^2/day)
Anisotropy ratio (K_z/K_x)	1/3
Effective Porosity (ϕ_e)	0.2
Storativity (S)	3.6E-04
Longitudinal Dispersivity (α_L)	15 m (49 ft)
Vertical Dispersivity (α_V)	0.3 m (1 ft)
Injection well length	74m (243 ft)
Boulder Zone TDS concentration	36.2 kg/m^3
Boulder Zone aquifer thickness	152 m (500 ft)
Horizontal grid spacing	45 m (uniform) (148 ft)
Vertical grid spacing	2 m (uniform) (6.5 ft)
Distribution Coefficient (K_d)	0 ml/g (all species)[a]
Initial head in Boulder Zone	1.9 m (6.2 ft) NAVD 88

(a) With consideration of non-zero K_d values for the evaluated partitioning radionuclides, the total dose from the partitioning radionuclides would be reduced.

Source: References 209, 210, 211, 212, 213, 214

Table 11.2-203
Peak Activity Concentrations at the 2.2-Mile Location

Case	Peak Activity Concentrations from 2 Units at 2.2 mi from Injection Point (pCi/L)[a]			
	H-3[b]	Cs-134	Cs-137	Sr-90
Base case	3.1E04	7.7E-03	7.6E-01	5.6E-04
Sensitivity Cases				
Φ_e = 15% (decreased Φ_e)	4.0E04 (+29%)	2.1E-02 (+173%)	8.6E-01 (+13%)	6.4E-04 (+14%)
α_V =0.1 m (decreased α_V)	3.9E04 (+26%)	1.2E-02 (+56%)	8.6E-01 (+13%)	6.3E-04 (+13%)
T = 55,736 m^2/day (increased T)	3.7E04 (+19%)	2.2E-02 (+186%)	8.1E-01 (+7%)	6.0E-04 (+7%)
b = 92 m (decreased b)	3.6E04 (+16%)	1.5E-02 (+95%)	8.2E-01 (+8%)	6.0E-04 (+7%)
K_z=0.1K_x (decreased K_z/K_x)	3.1E04 (0%)	7.8E-03 (+1%)	7.6E-01 (0%)	5.6E-04 (0%)
α_L= 5 m (decreased α_L)	3.1E04 (0%)	7.5E-03 (–3%)	7.6E-01 (0%)	5.6E-04 (0%)
α_L= 30 m (increased α_L)	3.1E04 (0%)	8.1E-03 (+5%)	7.6E-01 (0%)	5.6E-04 (0%)
S = 1E-3 (increased S)	3.1E04 (0%)	7.7E-03 (0%)	7.6E-01 (0%)	5.6E-04 (0%)
S = 1E-4 (decreased S)	3.1E04 (0%)	7.7E-03 (0%)	7.6E-01 (0%)	5.6E-04 (0%)
Saltwater injection 60 days per year	2.4E04 (–23%)	3.5E-03 (–55%)	6.5E-01 (–14%)	4.8E-04 (–14%)
α_V= 1.0 m (increased α_V)	2.3E04 (–26%)	4.0E-03 (–48%)	6.3E-01 (–17%)	4.6E-04 (–18%)
T = 5573 m^2/day (decreased T)	2.0E04 (–35%)	5.6E-04 (–93%)	6.4E-01 (–16%)	4.7E-04 (–16%)

(a) Values in parentheses represent changes in peak concentration relative to the base case on a percentage basis.
(b) Tritium contributes more than 90 percent of the member-of-the-public dose over the period in which these peak concentrations are seen.

Notes:
T = transmissivity
b = aquifer thickness (note that in this simulation the transmissivity value is the same as that of the base case and therefore hydraulic conductivity increases)
Φ_e = effective porosity
α_V = vertical dispersivity
α_L = longitudinal dispersivity
K_z = vertical hydraulic conductivity
K_x =horizontal hydraulic conductivity
S = storativity

Concentrations are from a simulated observation well in model layer 1.

Table 11.2-204
Cumulative Isotopic Inventory at End of Plant Operations

Isotope	Release per Unit (Ci/yr)[a]	Subsurface Activity at 61 years (Ci)
H-3	1.26E03	2.17E04
Na-24	2.04E-03	5.02E-06
Cr-51	2.31E-03	2.53E-04
Mn-54	1.63E-03	2.01E-03
Fe-55	1.25E-03	4.93E-03
Fe-59	2.50E-04	4.40E-05
Co-58	4.20E-03	1.18E-03
Co-60	5.50E-04	4.18E-03
Zn-65	5.13E-04	4.95E-04
Br-84	2.50E-05	2.18E-09
Rb-88	3.38E-04	1.65E-08
Sr-89	1.25E-04	2.50E-05
Sr-90	1.25E-05	4.00E-04
Sr-91	2.50E-05	3.97E-08
Y-91m	1.25E-05	1.71E-09
Y-93	1.13E-04	1.89E-07
Zr-95	2.88E-04	7.28E-05
Nb-95	2.63E-04	3.63E-05
Mo-99	7.13E-04	7.74E-06
Tc-99m	6.88E-04	6.81E-07
Ru-103	6.17E-03	9.57E-04
Ru-106	9.20E-02	1.36E-01
Rh-103m	6.17E-03	9.50E-07
Rh-106	9.20E-02	1.25E-07
Ag-110m	1.31E-03	1.30E-03
Ag-110	1.75E-04	1.97E-10
Te-129m	1.50E-04	1.99E-05
Te-129	1.88E-04	3.58E-08
Te-131m	1.13E-04	5.56E-07
Te-131	3.75E-05	2.58E-09
Te-132	3.00E-04	3.80E-06
I-131	1.77E-02	5.59E-04
I-132	2.05E-03	7.75E-07
I-133	8.38E-03	2.87E-05
I-134	1.01E-03	1.46E-07
I-135	6.22E-03	6.73E-06
Cs-134	1.24E-02	3.70E-02
Cs-136	7.88E-04	4.10E-05
Cs-137	1.67E-02	5.45E-01
Ba-137m	1.56E-02	1.10E-07
Ba-140	6.90E-03	3.48E-04
La-140	9.29E-03	6.16E-05
Ce-141	1.13E-04	1.45E-05
Ce-143	2.38E-04	1.29E-06
Ce-144	3.95E-03	4.45E-03
Pr-143	1.63E-04	8.72E-06
Pr-144	3.95E-03	1.87E-07
W-187	1.63E-04	6.35E-07
Np-239	3.00E-04	2.80E-06
Total		**4.35E04**[b]

(a) Release per unit values are based on the AP1000 DCD values (as described in the Radioac ive Source Term section above).
(b) The "Total" value represents the sum of all isotopes, multiplied by 2 to account for multiple units.

Table 11.2-205 (Sheet 1 of 2)
Results of Initial Exposure Pathway Scenario Screening

Location	DIS Operation Mode	Description	Retained for Further Analysis	Member-of-the-public Type/Location
Plant Area	Normal Operation	Migration through the middle confining unit	No – injectate contained in middle confining unit	Not Applicable
	Off-Normal Operation	Worker exposure at leaking pipe	No –controlled by occupational radiation control program	Not Applicable
		Worker exposure to Biscayne aquifer	No – not considered feasible	Not Applicable
		Middle confining unit failure	No – not considered feasible	Not Applicable
		Migration through the middle and intermediate confining units	No – not considered feasible	Not Applicable
		Catastrophic failure of deep injection well	No – not considered feasible	Not Applicable
		Middle confining unit failure and injectate travel to Unit 5 Upper Floridan wells	No – not considered feasible	Not Applicable
	Inadvertent Intrusion	Not Applicable	Not Applicable	Not Applicable
Property Area	Normal Operation	Migration through the middle confining unit	No – Injectate contained in middle confining unit	Not Applicable
	Off-Normal Operation	Middle confining unit failure	No – not considered feasible	Not Applicable
		Migration through the middle and intermediate confining units	No – not considered feasible	Not Applicable
	Inadvertent Intrusion	Not Applicable	Not Applicable	Not Applicable

Table 11.2-205 (Sheet 2 of 2)
Results of Initial Exposure Pathway Scenario Screening

Location	DIS Operation Mode	Description	Retained for Further Analysis	Member-of-the-public Type/Location
Beyond Property Area	Normal Operation	Migration through the middle confining unit	No – injectate contained in middle confining unit	Not Applicable
	Off-Normal Operation	Middle confining unit failure	Yes	Refer to Table 11.2-207
		Migration through the middle and intermediate confining units	No – not considered feasible	Not Applicable
	Inadvertent Intrusion	Middle confining unit failure and member-of-the-public drilling and ingestion exposure	Yes (worst case)	Refer to Table 11.2-207

Table 11.2-206
Summary of Water Use in Miami-Dade County

Water User	Water Source							
	Biscayne Aquifer	Floridan Aquifer	Surficial Aquifer	Onsite Lake	Tamiami Aquifer	County Water	Canals	Borrow Pits
FPL (Unit 5)	—	3	—	—	—	—	—	—
Public[a]	173	1	8	1	—	—	—	—
Agricultural [a]	723	2	15	2	1	20	—	—
Aquaculture	20	—	—	—	—	—	—	—
Golf Course	60	—	—	30	—	22	—	—
Industrial	284	—	16	3	—	2	7	8
Landscape	762	—	19	93	—	9	33	—
Livestock	5	—	—	—	—	—	—	—
Nursery	673	—	6	2	—	16	1	—

(a) Floridan Aquifer use includes public use (Florida Keys Aqueduct Authority) and irrigation use (Card Sound Golf Club and Ocean Reef Club).

Table 11.2-207
Retained Dose Scenarios

Location	Exposure Pathway Mode	Description	Member-of-the-Public Type/ Location
Plant Area	None Retained		
Property Area	None Retained		
Beyond Property Area	Off-Normal Operation	Middle confining unit failure and member-of-the-public ingestion exposure (Non-Credible)	Beyond property boundary at closest private parcel
		Middle confining unit failure and member-of-the-public ingestion exposure (Credible)	Beyond property boundary at Ocean Reef Club Community
	Inadvertent Intrusion	Middle confining unit failure and member-of-the-public drilling and ingestion exposure (Worst Case)	Beyond property boundary at closest private parcel

Table 11.2-208
Member-of-the-Public Injectate Ingestion Dose Summary

Radionuclide	Total Body Dose for 2 Units (mrem/year)	Liver[a] Dose for 2 Units (mrem/year)
Tritium	1.8E00	1.8E00
Cesium-134	3.1E-04	1.5E-03
Cesium-137	1.8E-02	1.2E-01
Strontium-90	1.5E-04	0
Total	1.8	1.9

(a) Liver is the organ receiving the maximum dose.

Table 11.2-209
Inadvertent Intrusion Subsistence Driller Dose Summary

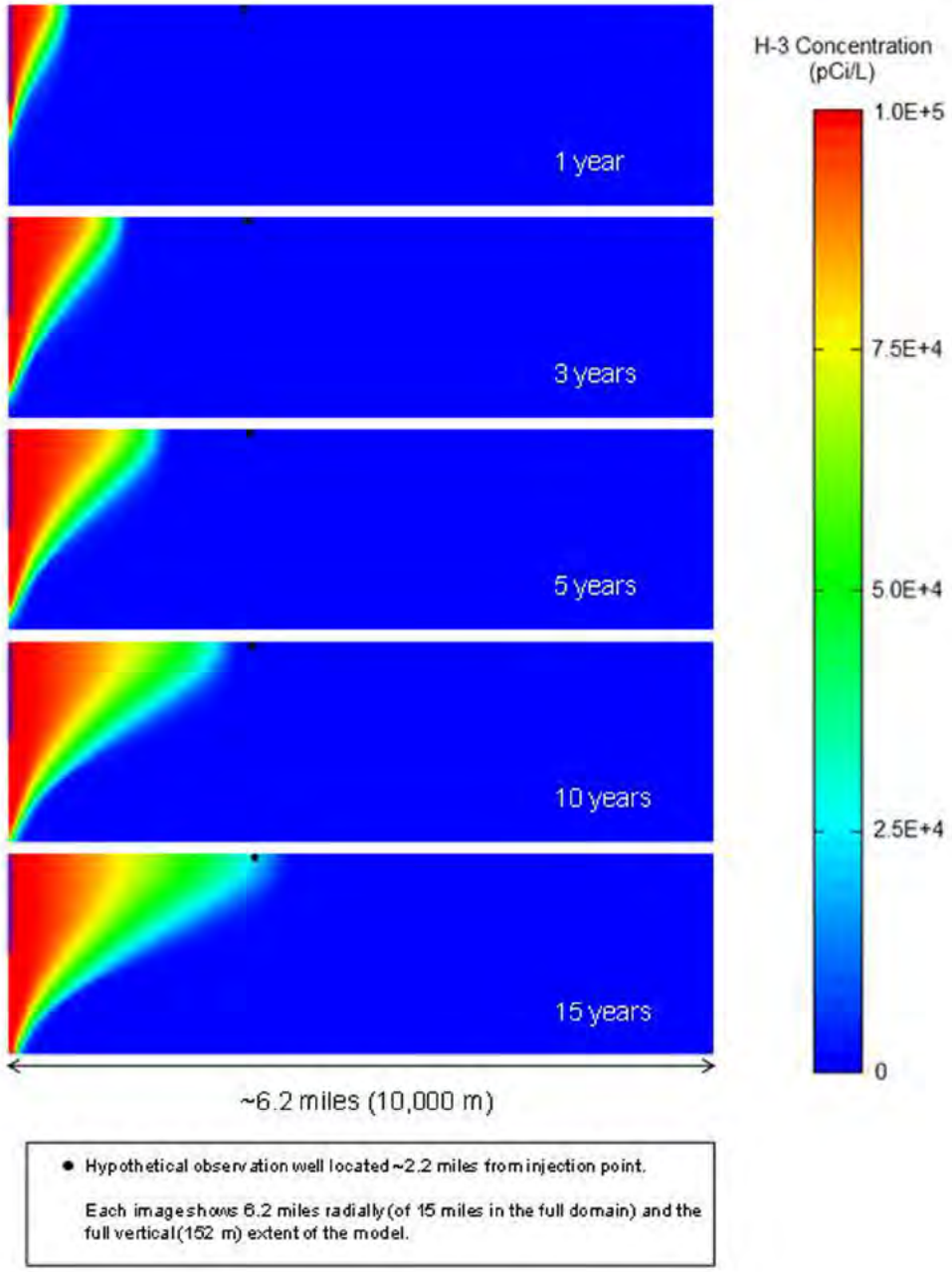
Pathway	Dose (mrem) per Unit[b]	
	Total Body	Liver[a]
Annual Ingestion of Water and Irrigated Foods	2.7	3.8
Inhalation During Drilling	8.2E-02	8.3E-02
Air Immersion During Drilling	2.6E-06	2.6E-06
Deposition During Drilling	1.8E-05	0
Total	2.8	3.9
10 CFR Part 50, Appendix I Design Objectives	3	10

(a) Liver is the organ receiving the maximum dose.
(b) Doses are calculated based on the operation of two units, as this maximizes the doses at offsite receptors. The calculated two-unit dose is then divided by two to obtain the dose per unit.

Table 11.2-210
Dose Summary

Location	Exposure Pathway Mode	Description	Location	Dose (peak airborne concentration)
Beyond Property Area	Off-Normal Operation	Middle confining unit failure and member-of-the-public ingestion exposure (Non-Credible)	Beyond Property Boundary at closest private parcel	1.8 mrem/year total body dose for 2 units
		Middle confining unit failure and member-of-the-public exposure – Ocean Reef Club Community (Credible)	Ocean Reef Club Community	0 mrem/year total body dose
	Inadvertent Intrusion	Middle confining unit failure and member-of-the-public drilling and ingestion exposure (Worst Case)	Beyond Property Boundary at closest private parcel	5.6 mrem/year total body dose for 2 units

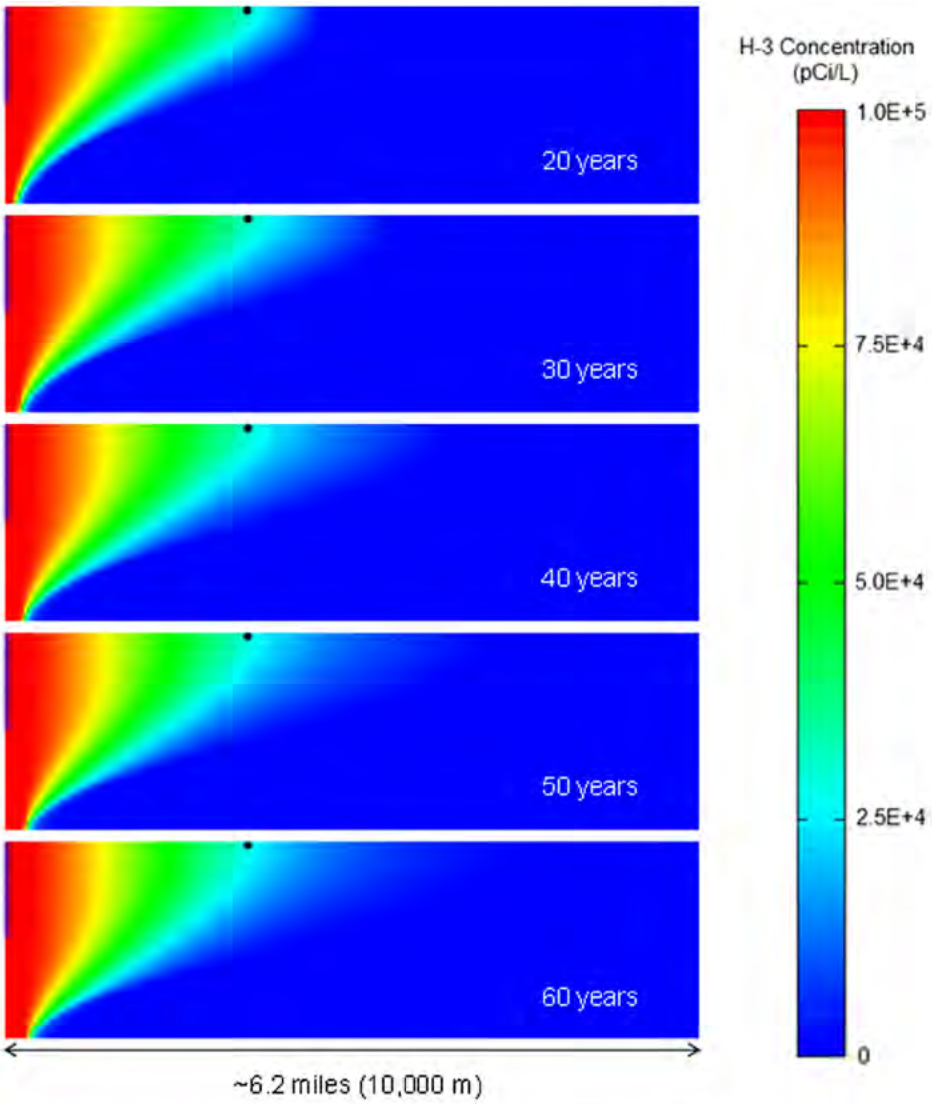
Figure 11.2-201 Base Case Boulder Zone Tritium Concentrations (Sheet 1 of 4)



● Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

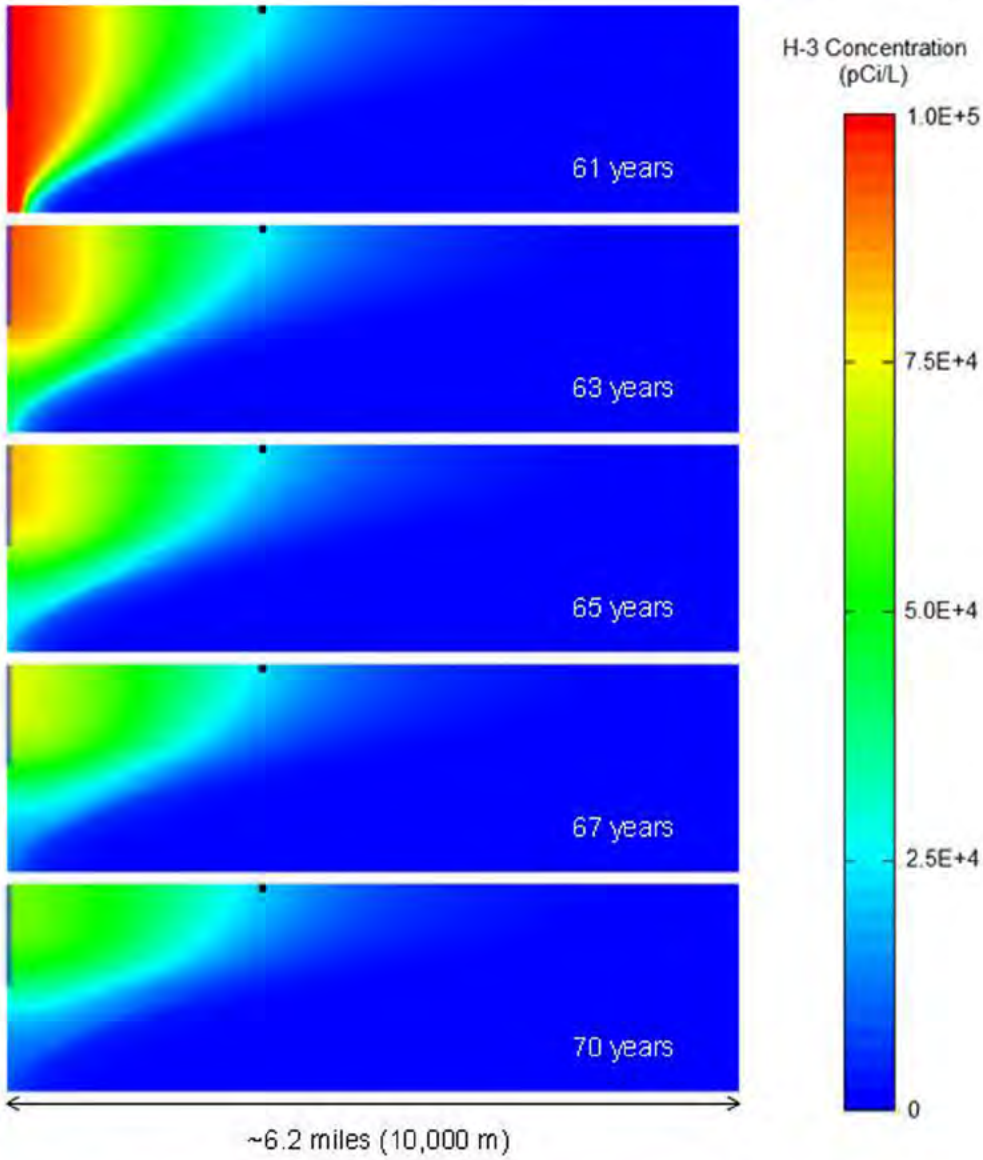
Figure 11.2-201 Base Case Boulder Zone Tritium Concentrations (Sheet 2 of 4)



● Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

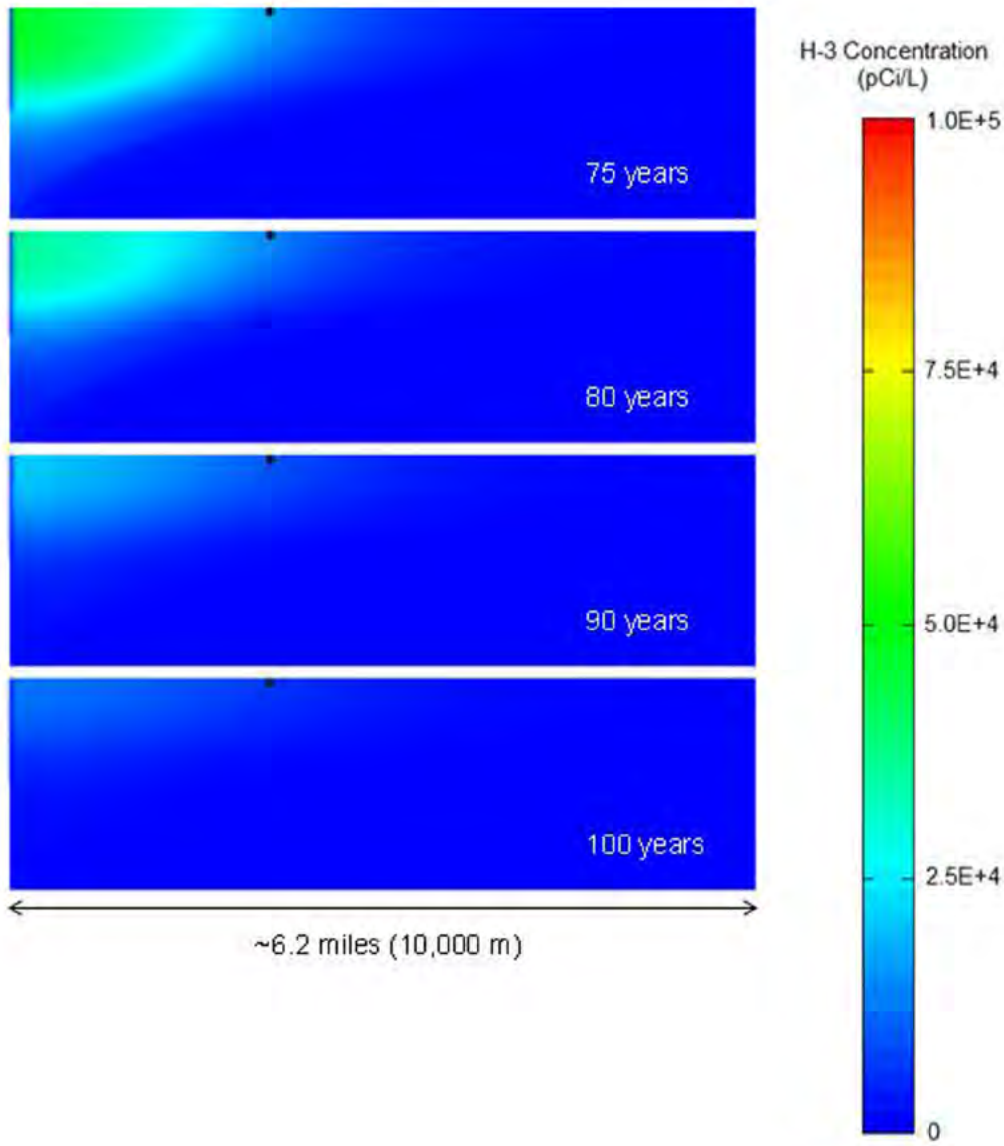
Figure 11.2-201 Base Case Boulder Zone Tritium Concentrations (Sheet 3 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-201 Base Case Boulder Zone Tritium Concentrations (Sheet 4 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-202 Model Layer 1 Distribution of Tritium in the Boulder Zone for the Base Case Simulation at the End of Plant Operations

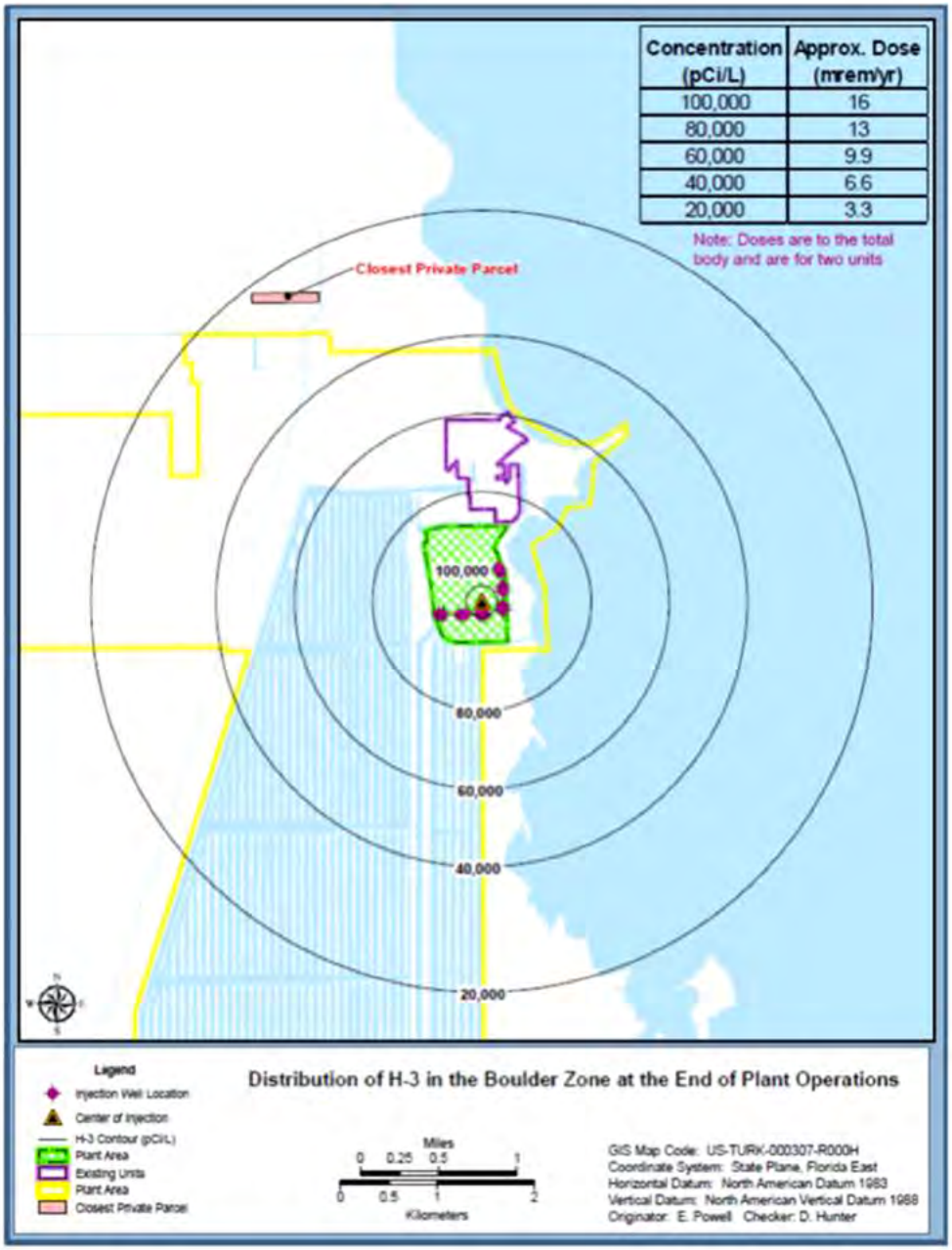


Figure 11.2-203 Base Case Boulder Zone Cesium-134 Concentrations (Sheet 1 of 4)

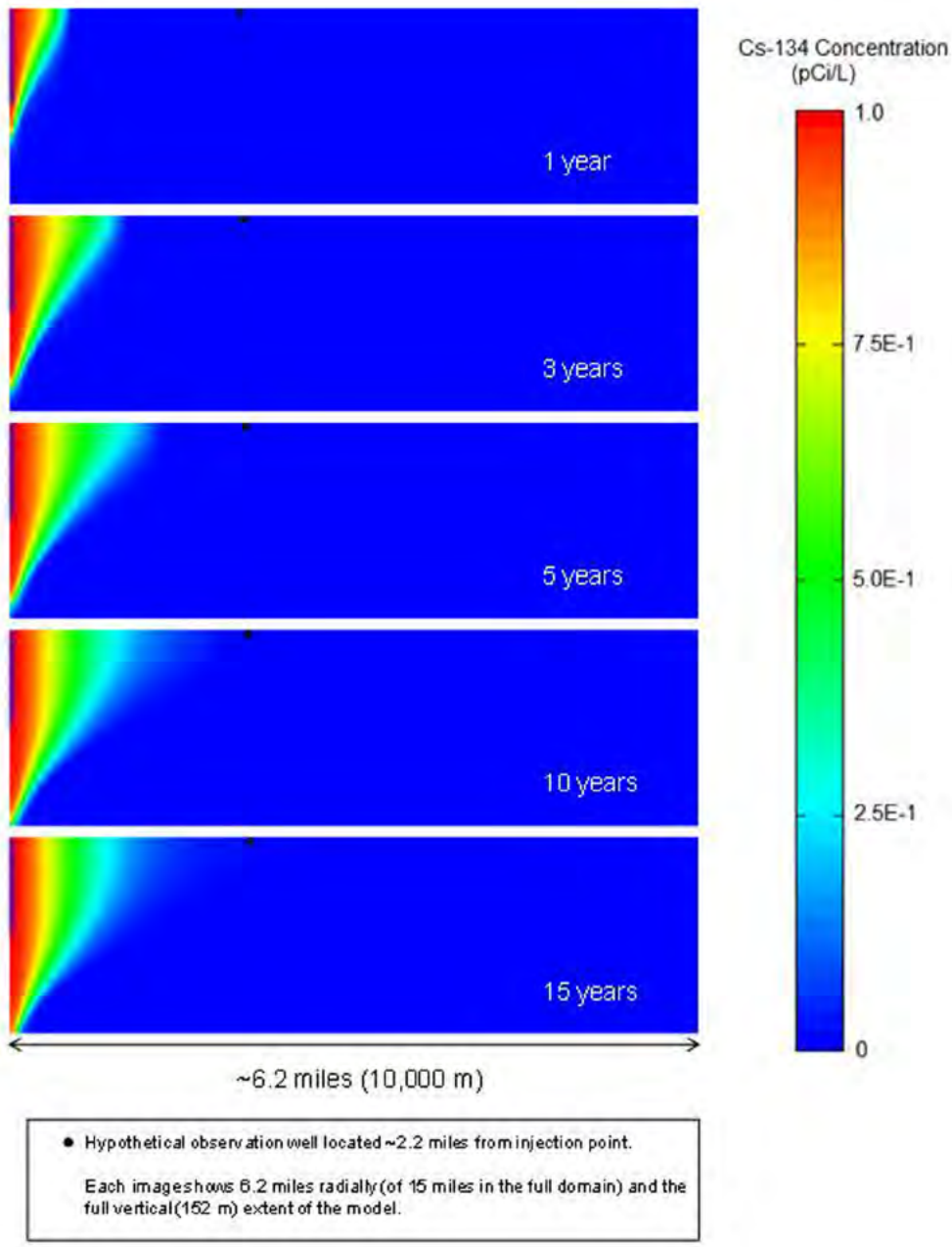
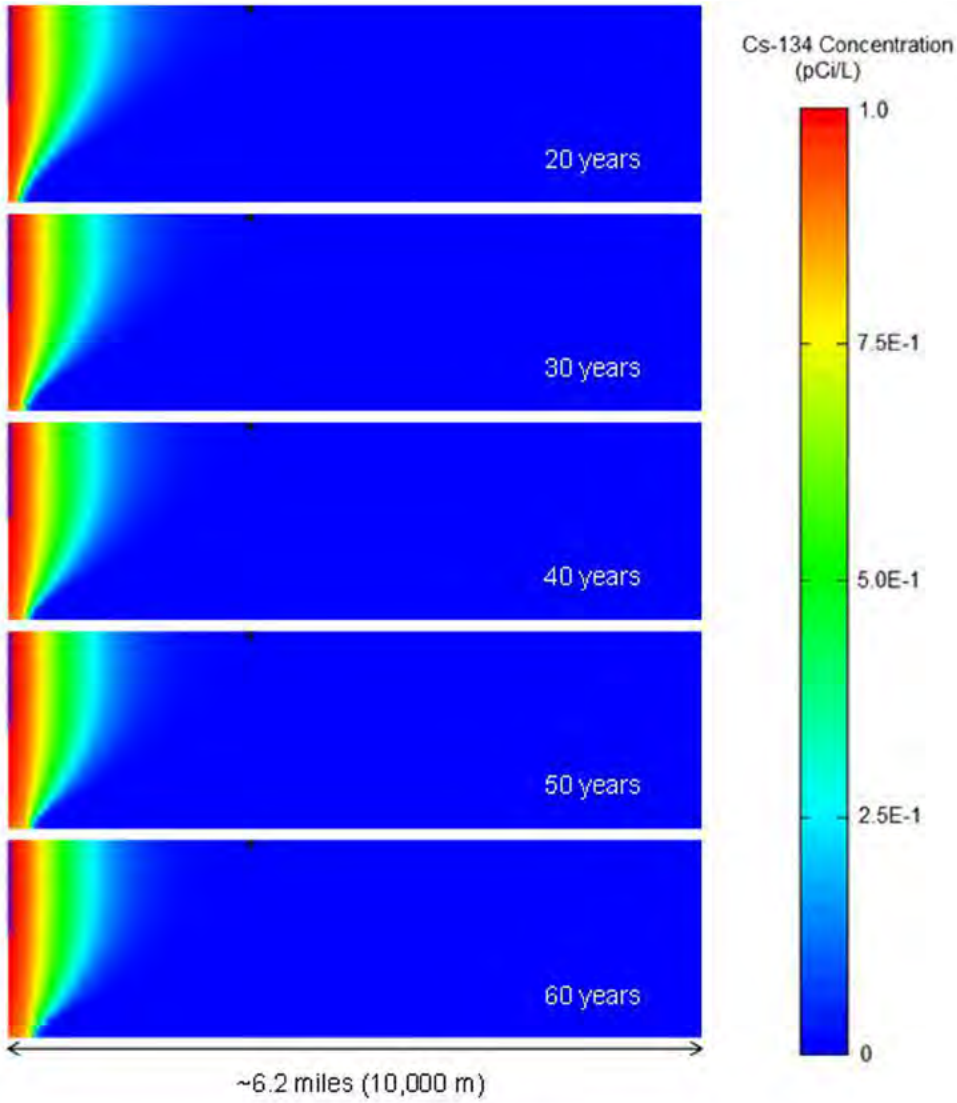


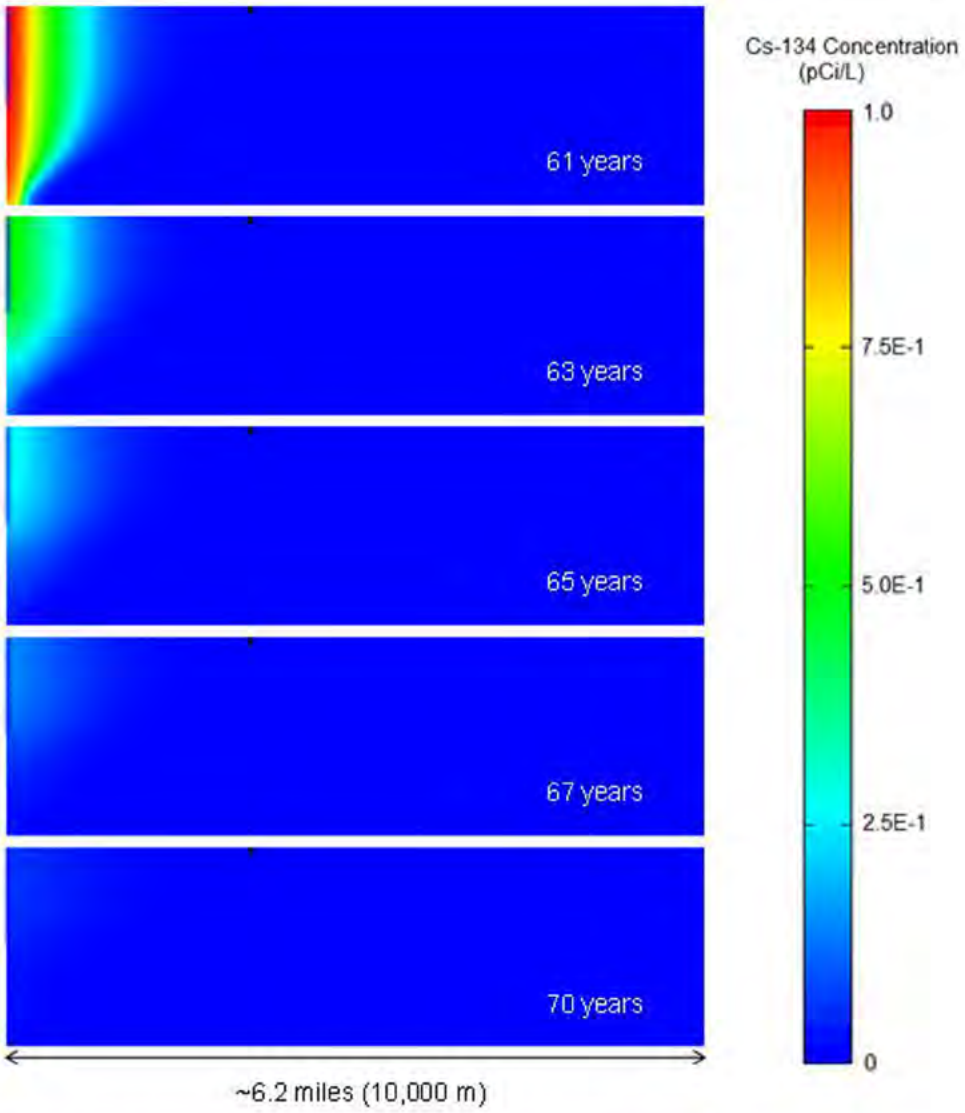
Figure 11.2-203 Base Case Boulder Zone Cesium-134 Concentrations (Sheet 2 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

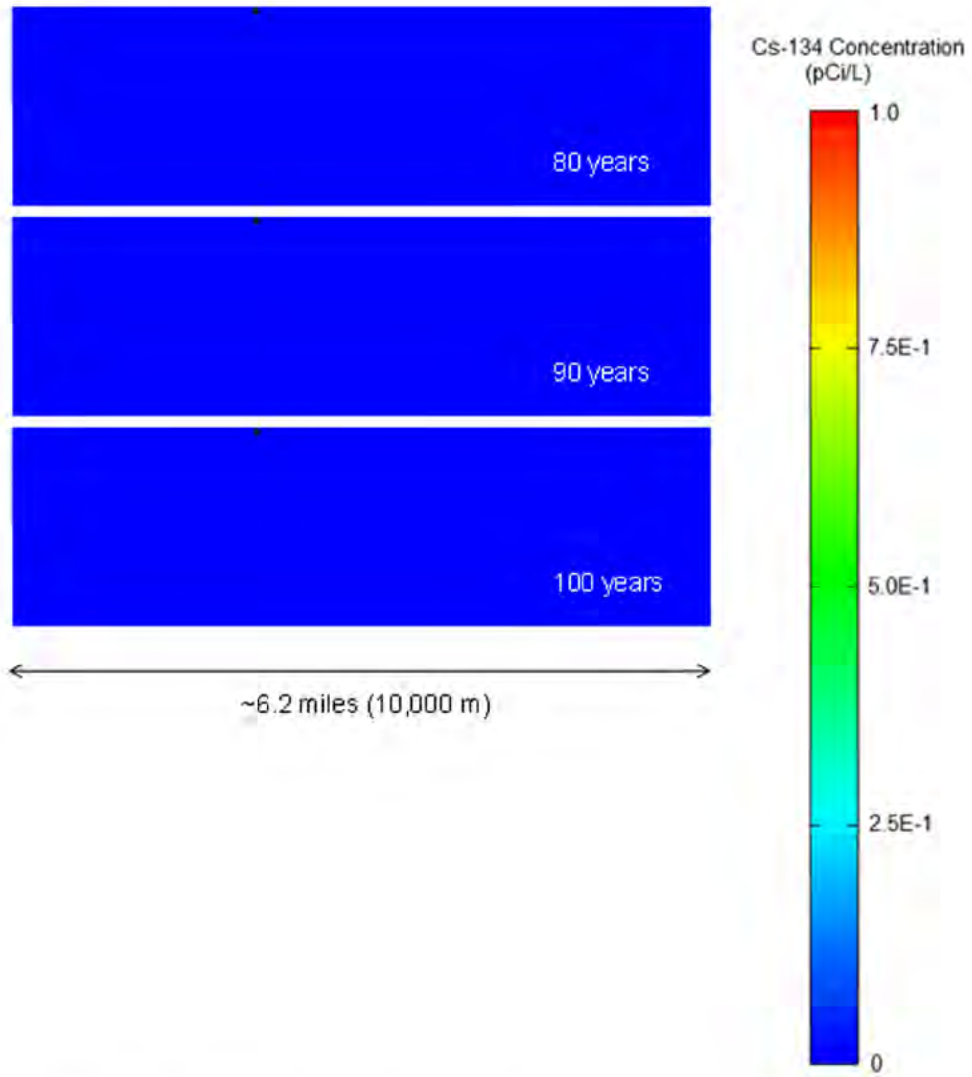
Figure 11.2-203 Base Case Boulder Zone Cesium-134 Concentrations (Sheet 3 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-203 Base Case Boulder Zone Cesium-134 Concentrations (Sheet 4 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-204 Model Layer 1 Distribution of Cesium-134 in the Boulder Zone for the Base Case Simulation at the End of Plant Operations

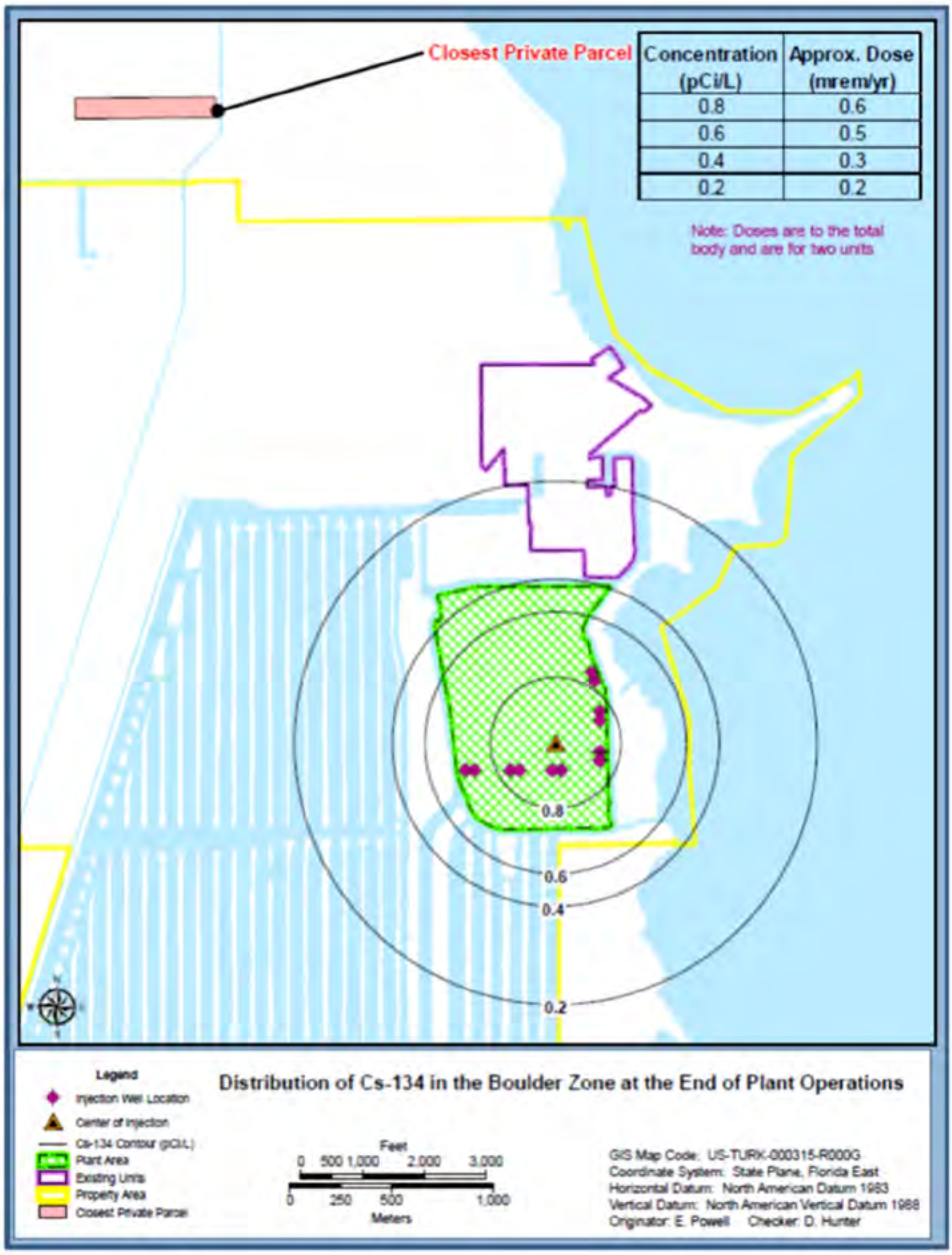
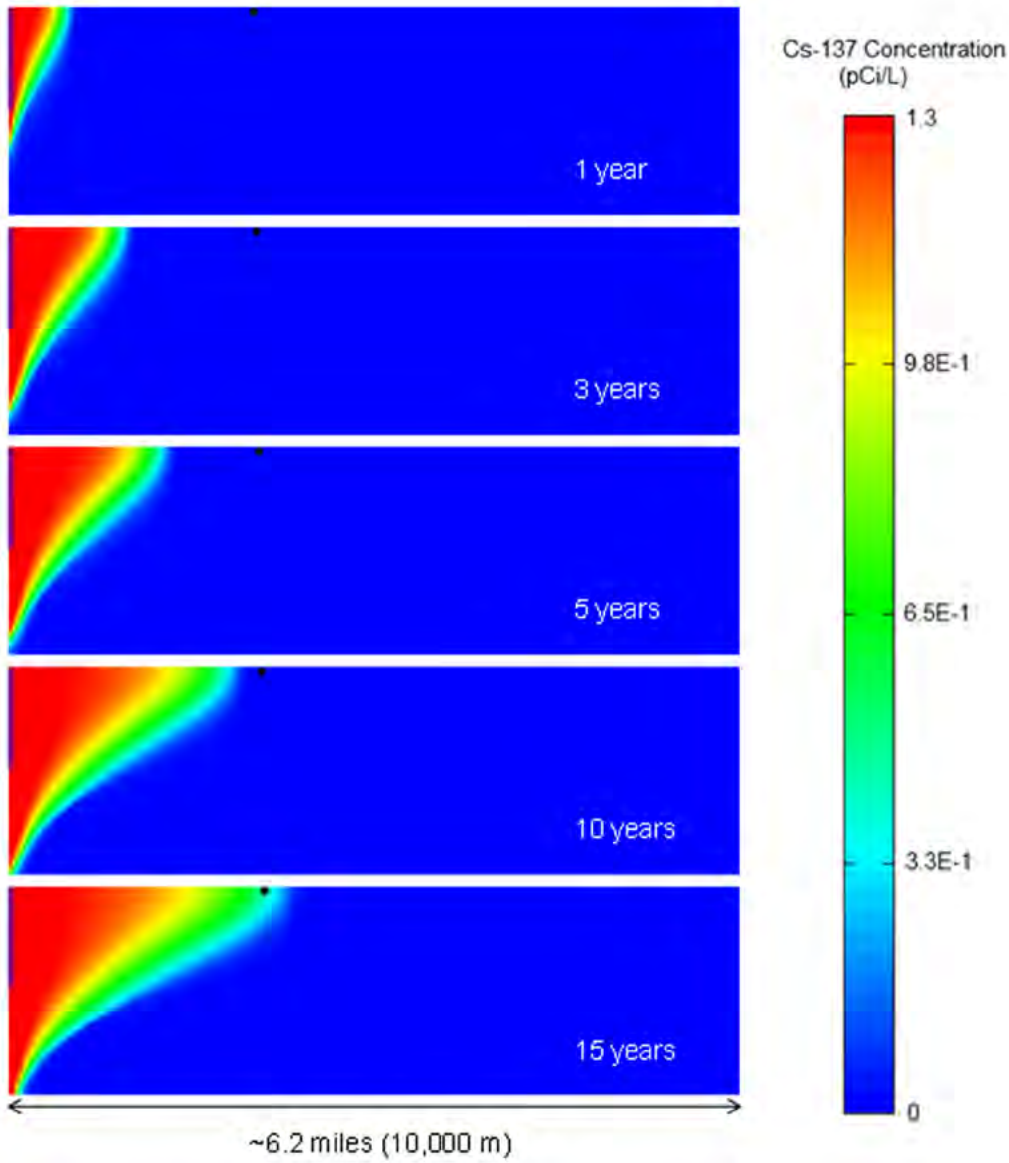


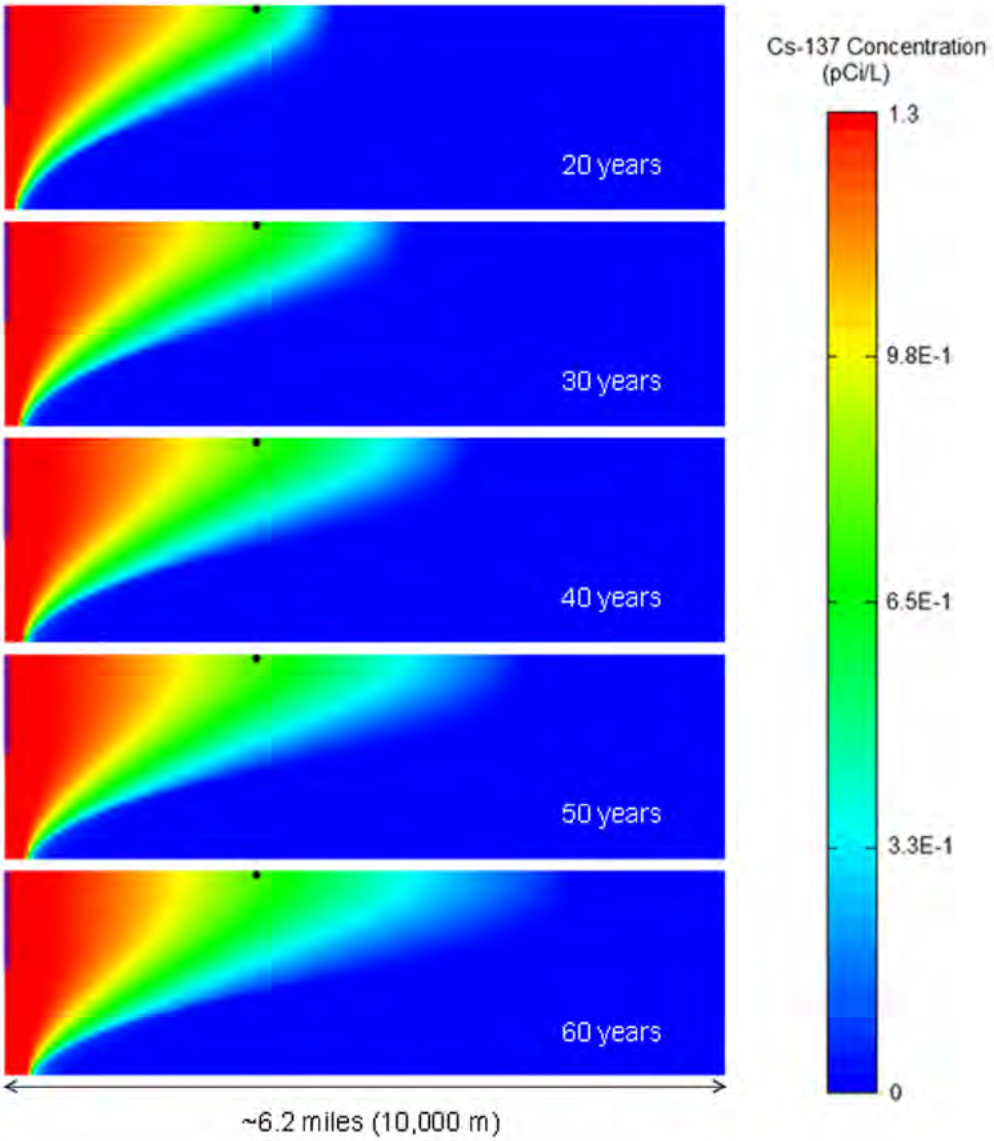
Figure 11.2-205 Base Case Boulder Zone Cesium-137 Concentrations (Sheet 1 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

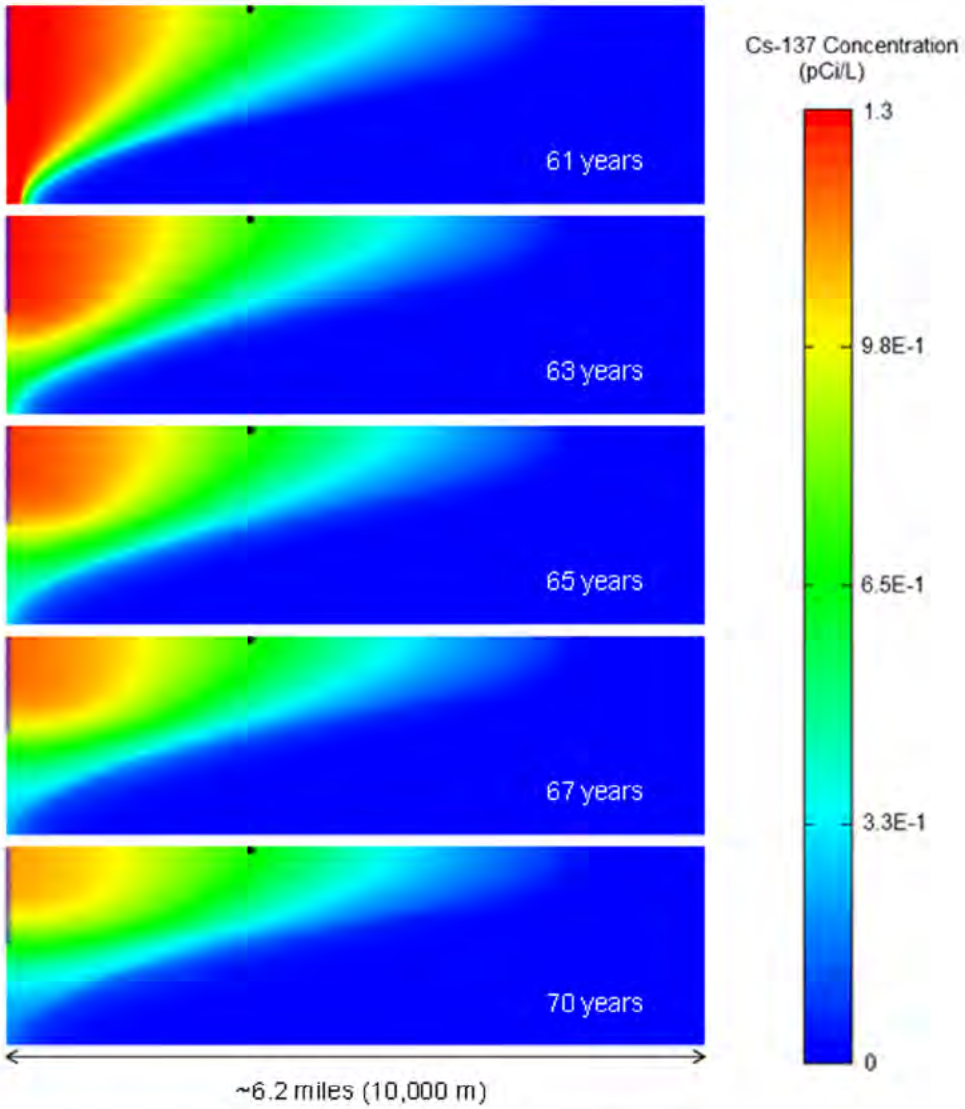
Figure 11.2-205 Base Case Boulder Zone Cesium-137 Concentrations (Sheet 2 of 4)



● Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-205 Base Case Boulder Zone Cesium-137 Concentrations (Sheet 3 of 4)



- Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-205 Base Case Boulder Zone Cesium-137 Concentrations (Sheet 4 of 4)

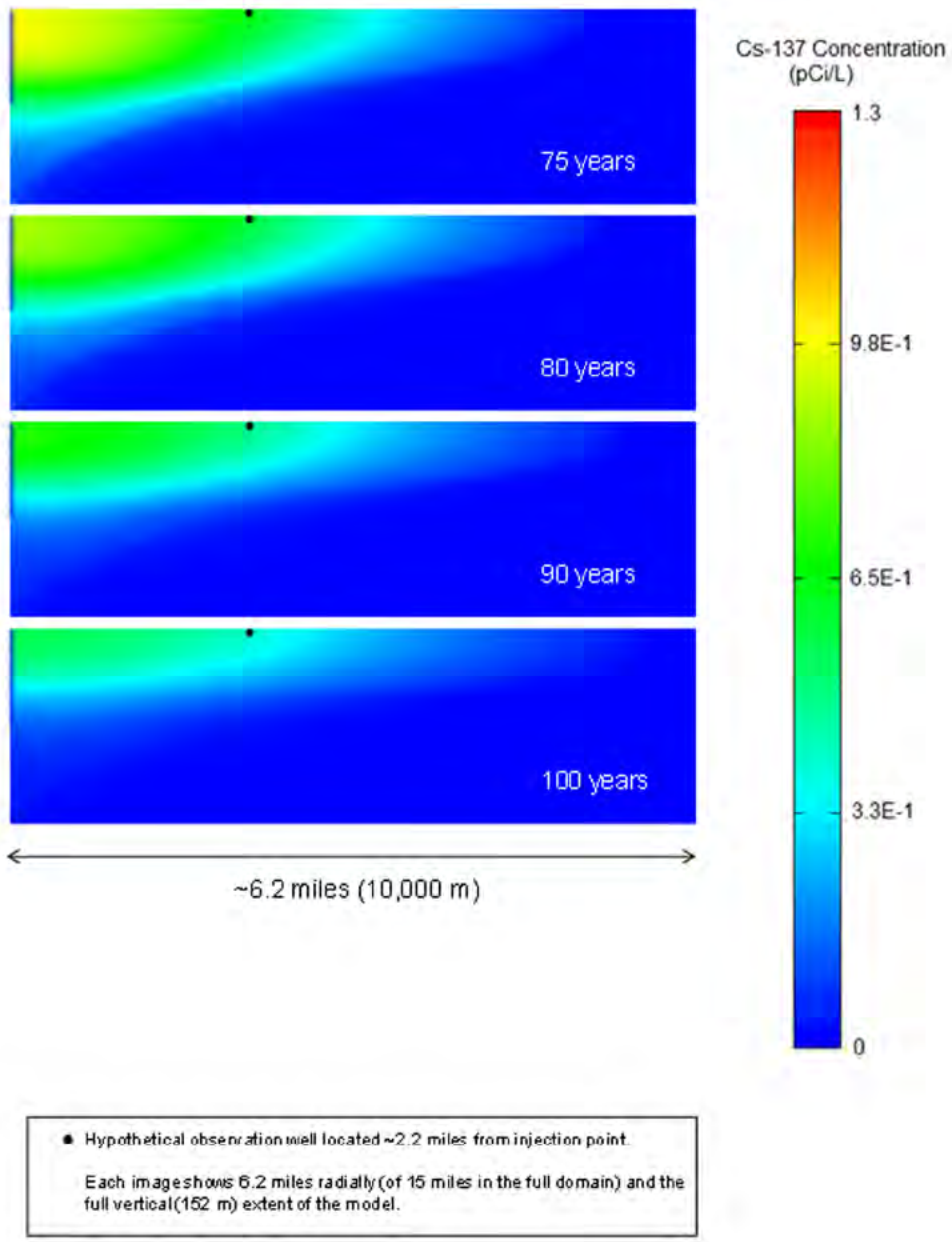


Figure 11.2-206 Model Layer 1 Distribution of Cesium-137 in the Boulder Zone for the Base Case Simulation the End of Plant Operations

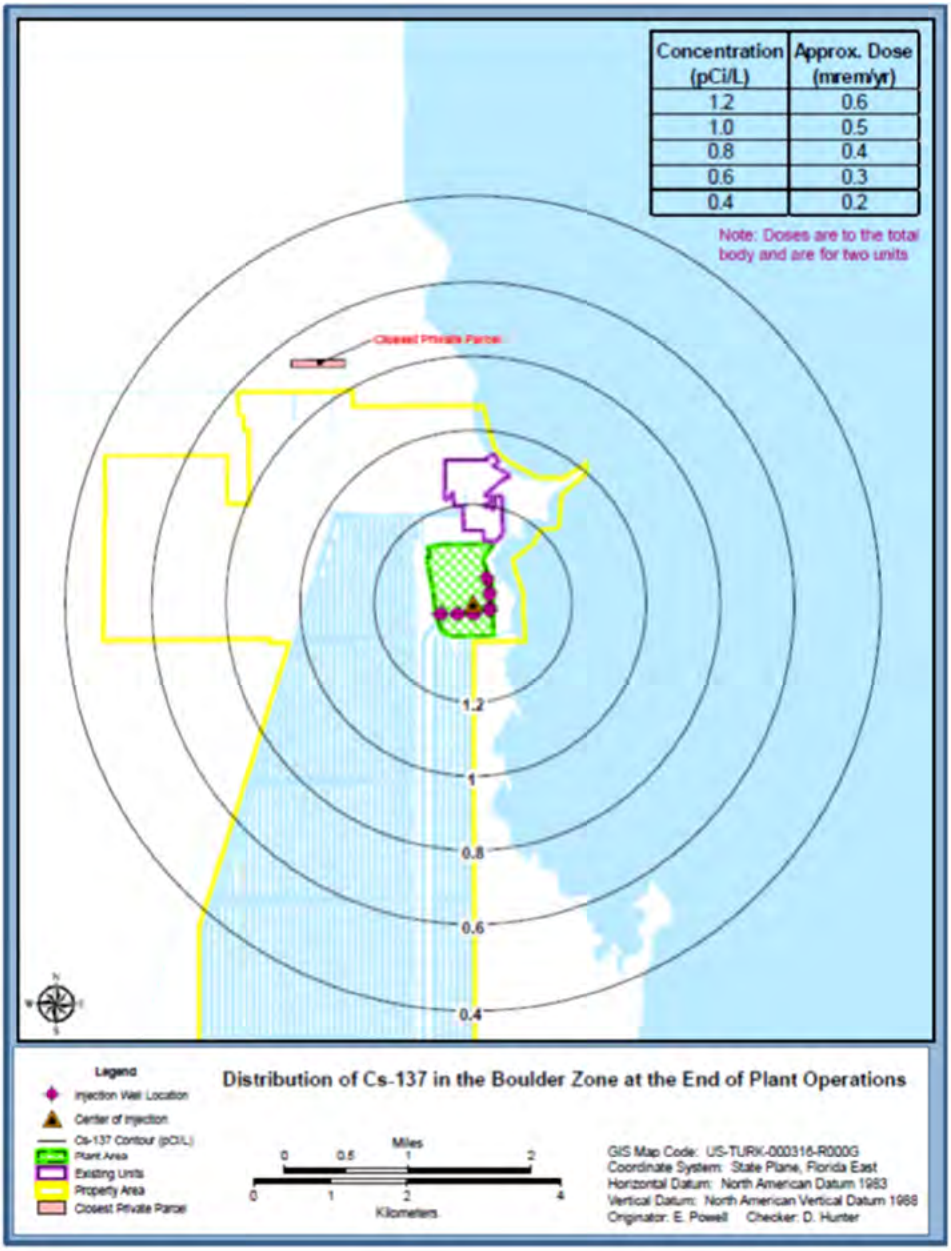
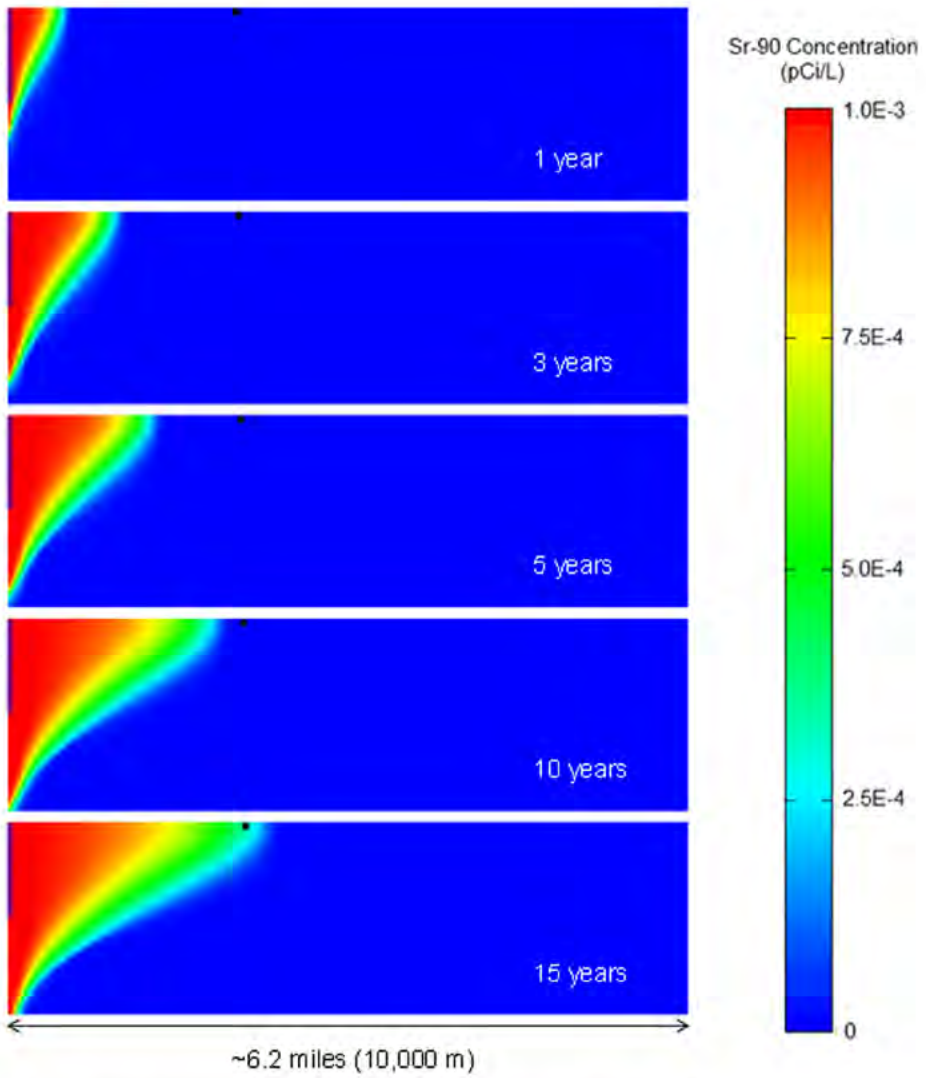


Figure 11.2-207 Base Case Boulder Zone Strontium-90 Concentrations (Sheet 1 of 4)



● Hypothetical observation well located ~2.2 miles from injection point.

Each image shows 6.2 miles radially (of 15 miles in the full domain) and the full vertical (152 m) extent of the model.

Figure 11.2-207 Base Case Boulder Zone Strontium-90 Concentrations (Sheet 2 of 4)

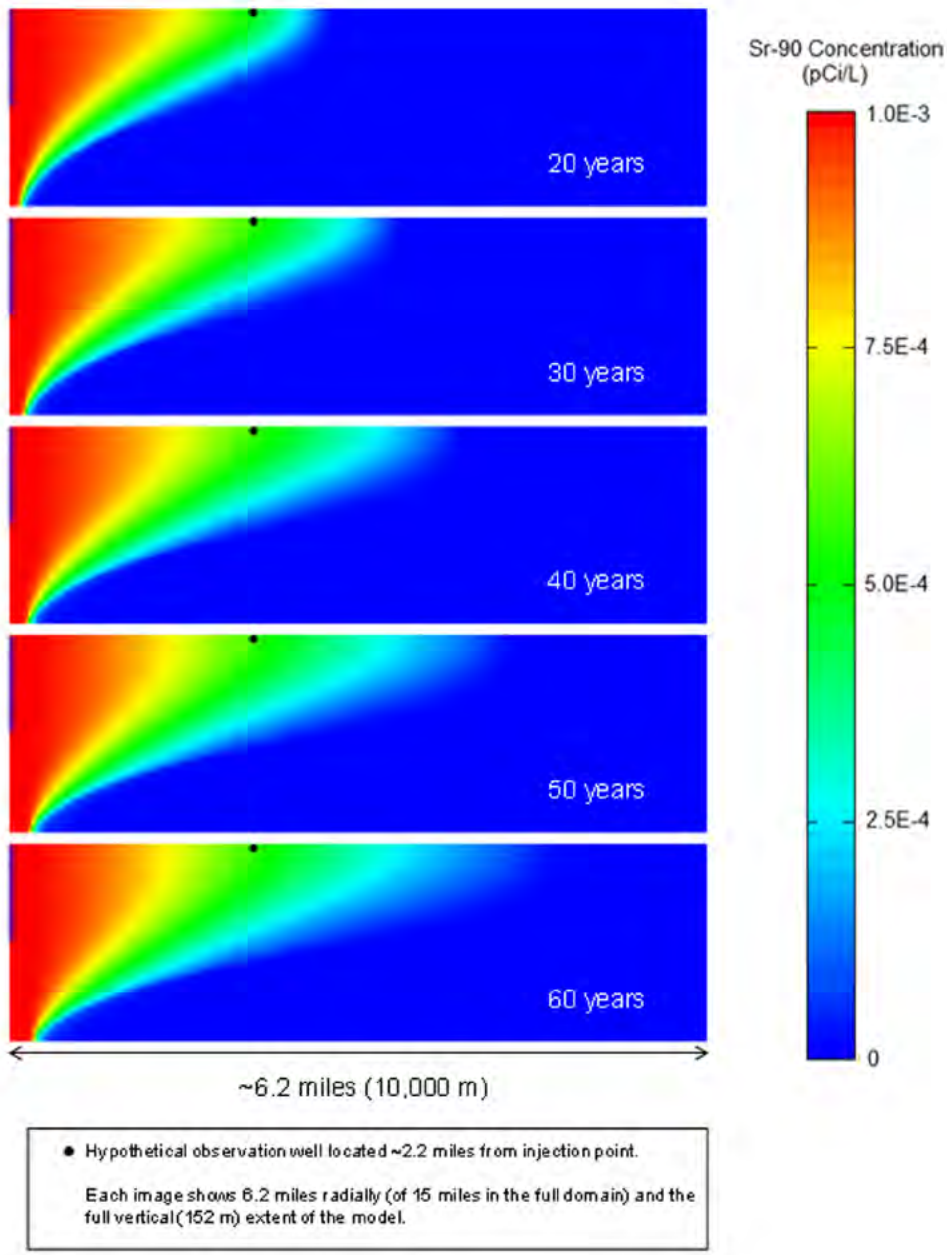


Figure 11.2-207 Base Case Boulder Zone Strontium-90 Concentrations (Sheet 3 of 4)

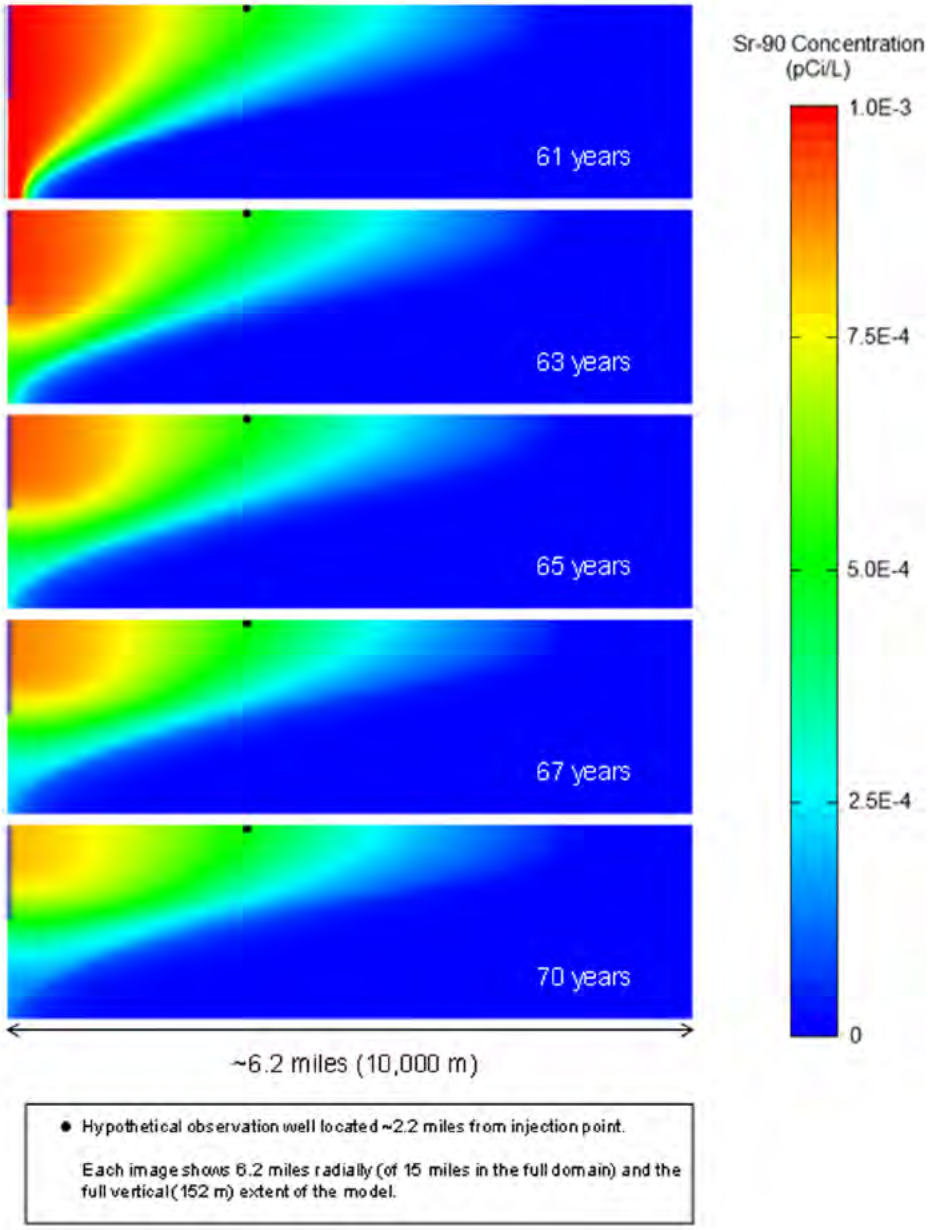


Figure 11.2-207 Base Case Boulder Zone Strontium-90 Concentrations (Sheet 4 of 4)

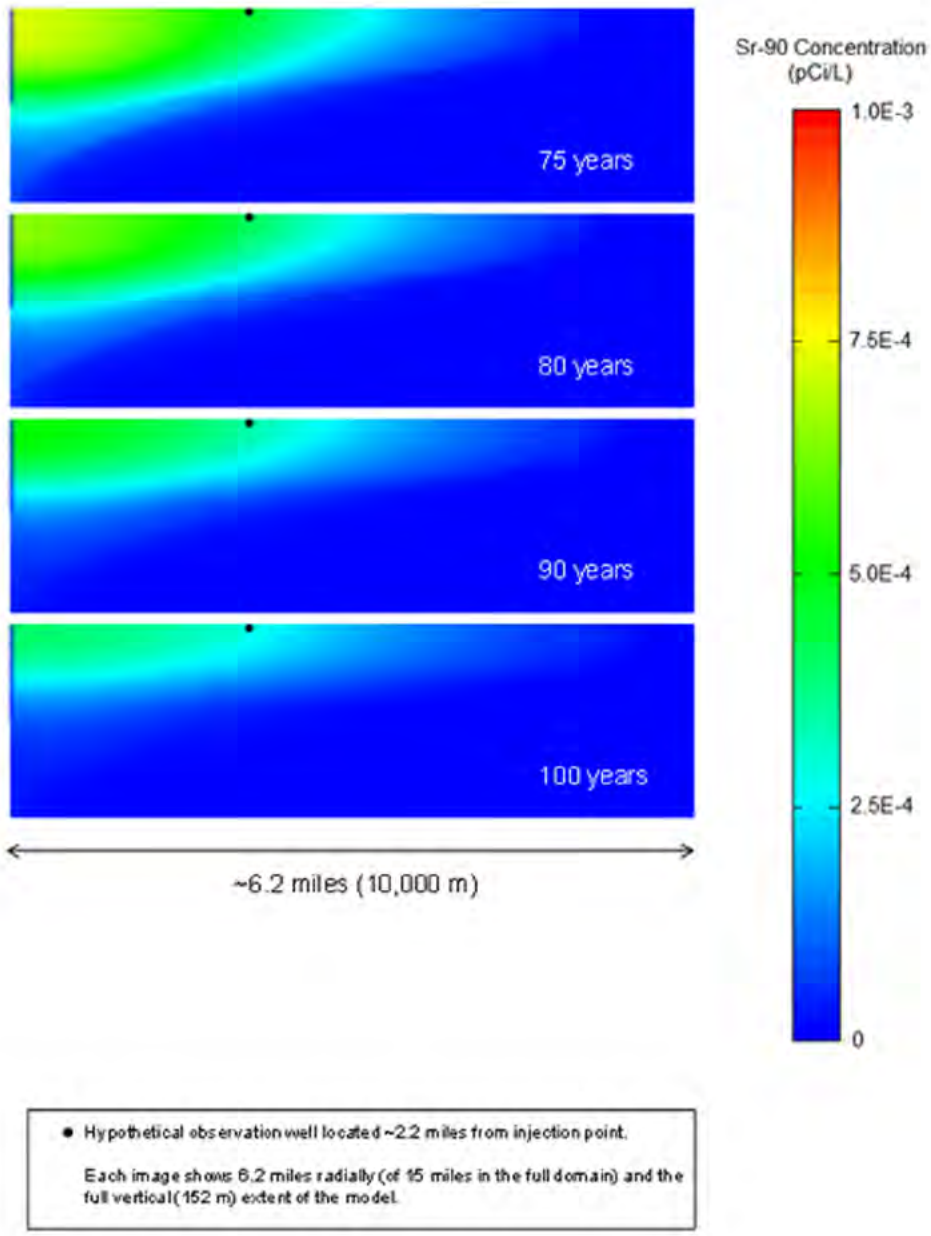


Figure 11.2-208 Model Layer 1 Distribution of Strontium-90 in the Boulder Zone for the Base Case Simulation at the End of Plant Operations

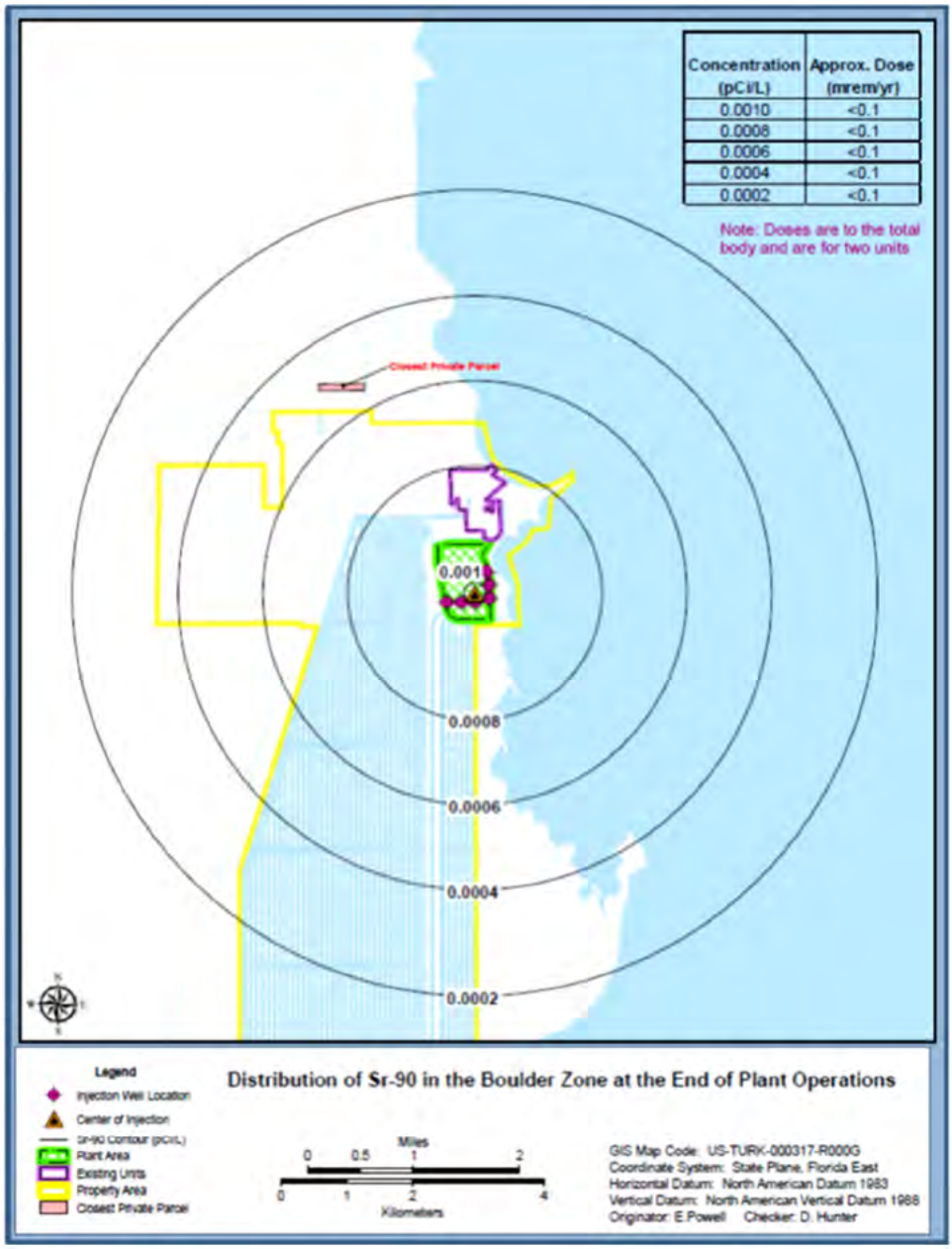


Figure 11.2-209 Model Layer 1 Base Case Relative Concentration Breakthrough Curves at 2.2-Mile Receptor Location

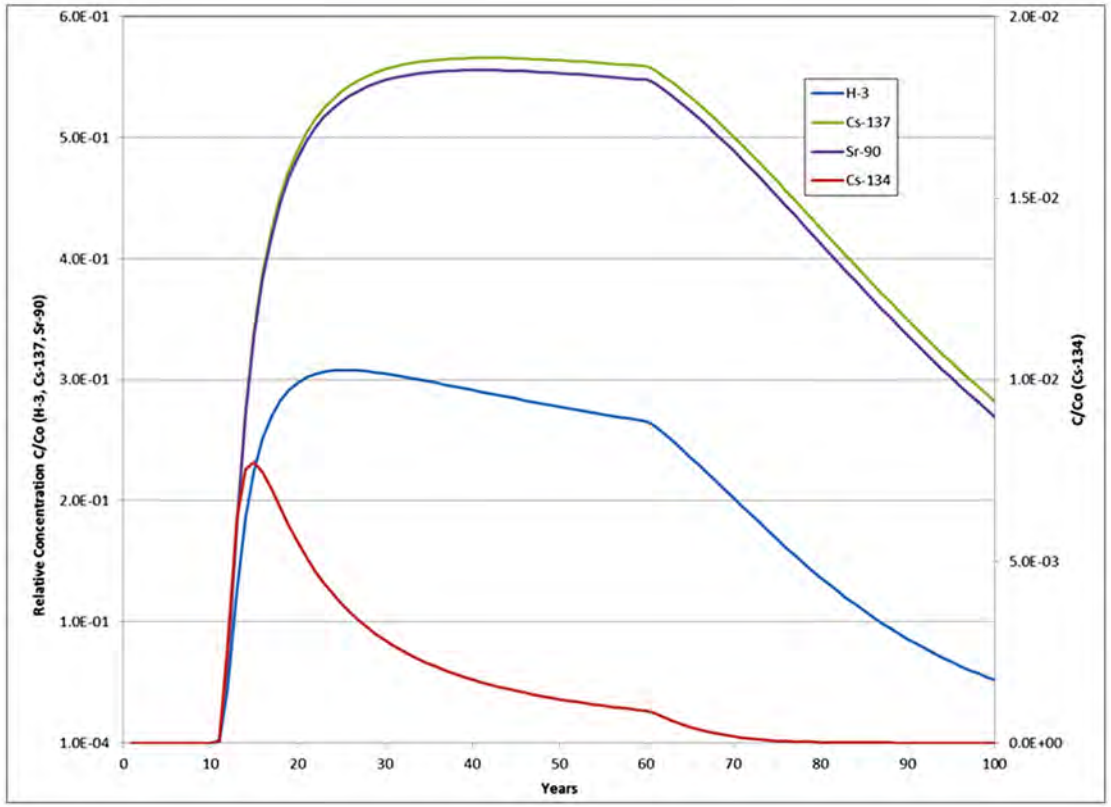


Figure 11.2-210 Six mrem Derived Tritium Activity Concentration Profiles in the Boulder Zone - Base Case Simulation

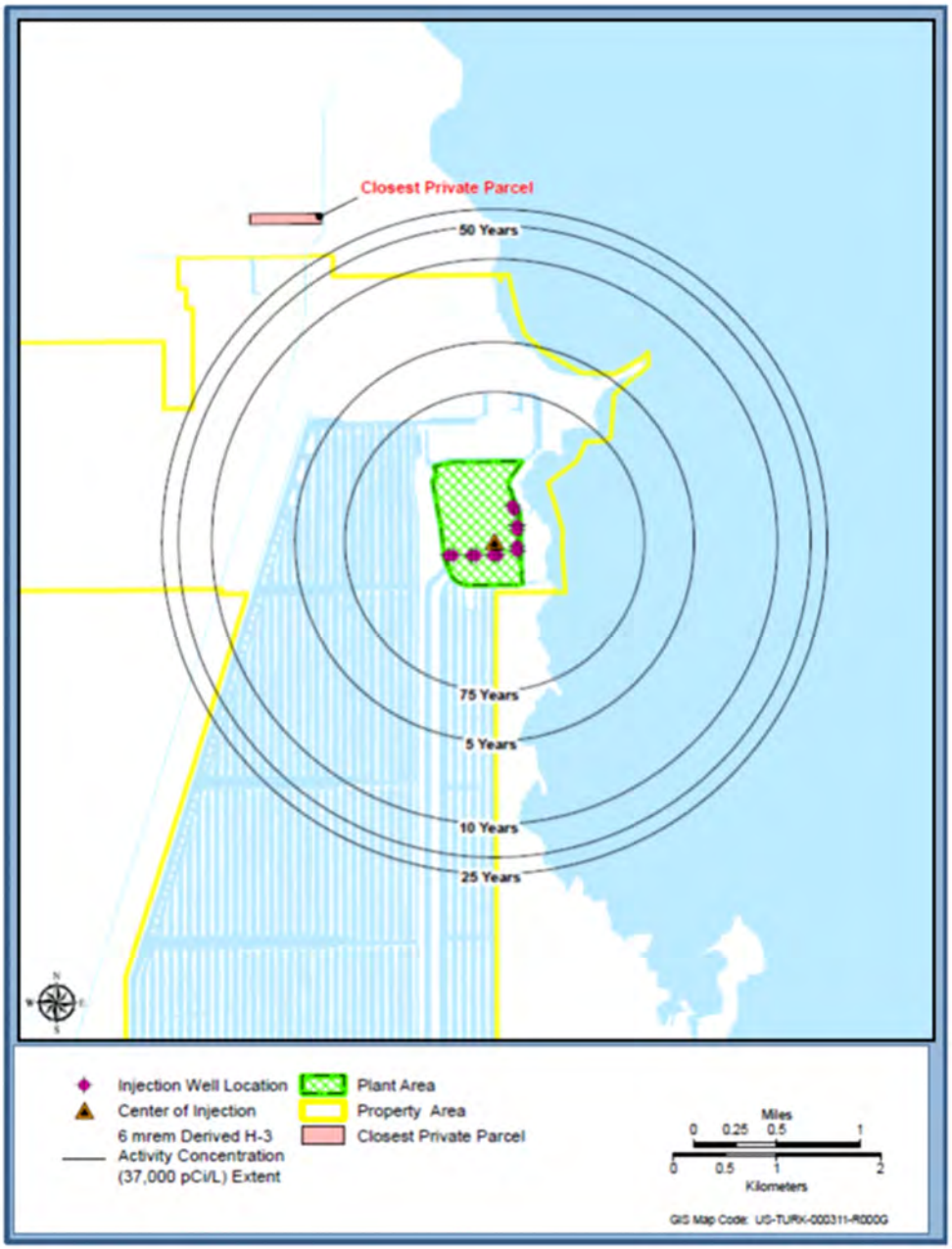


Figure 11.2-211 Potential Exposure Location Areas

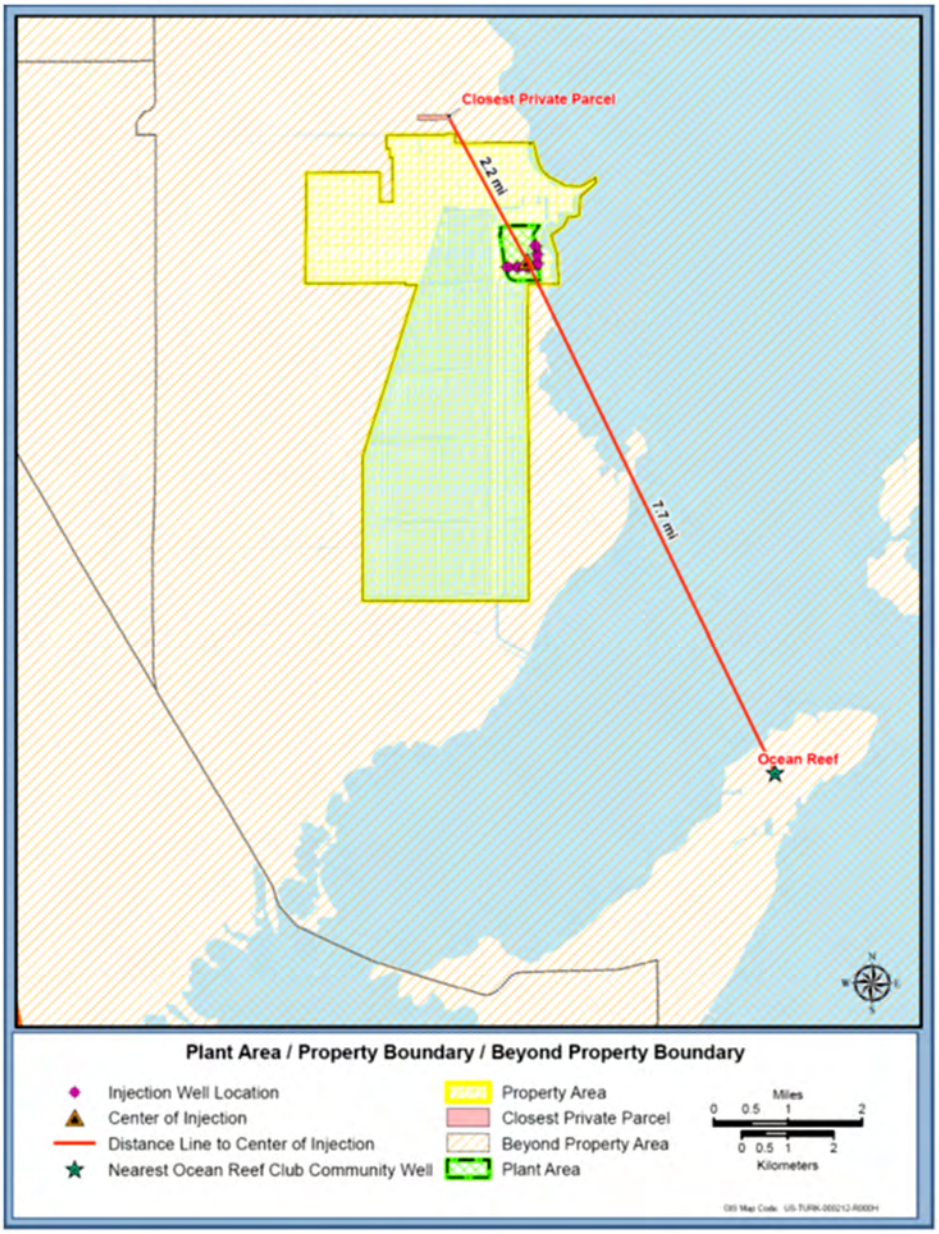
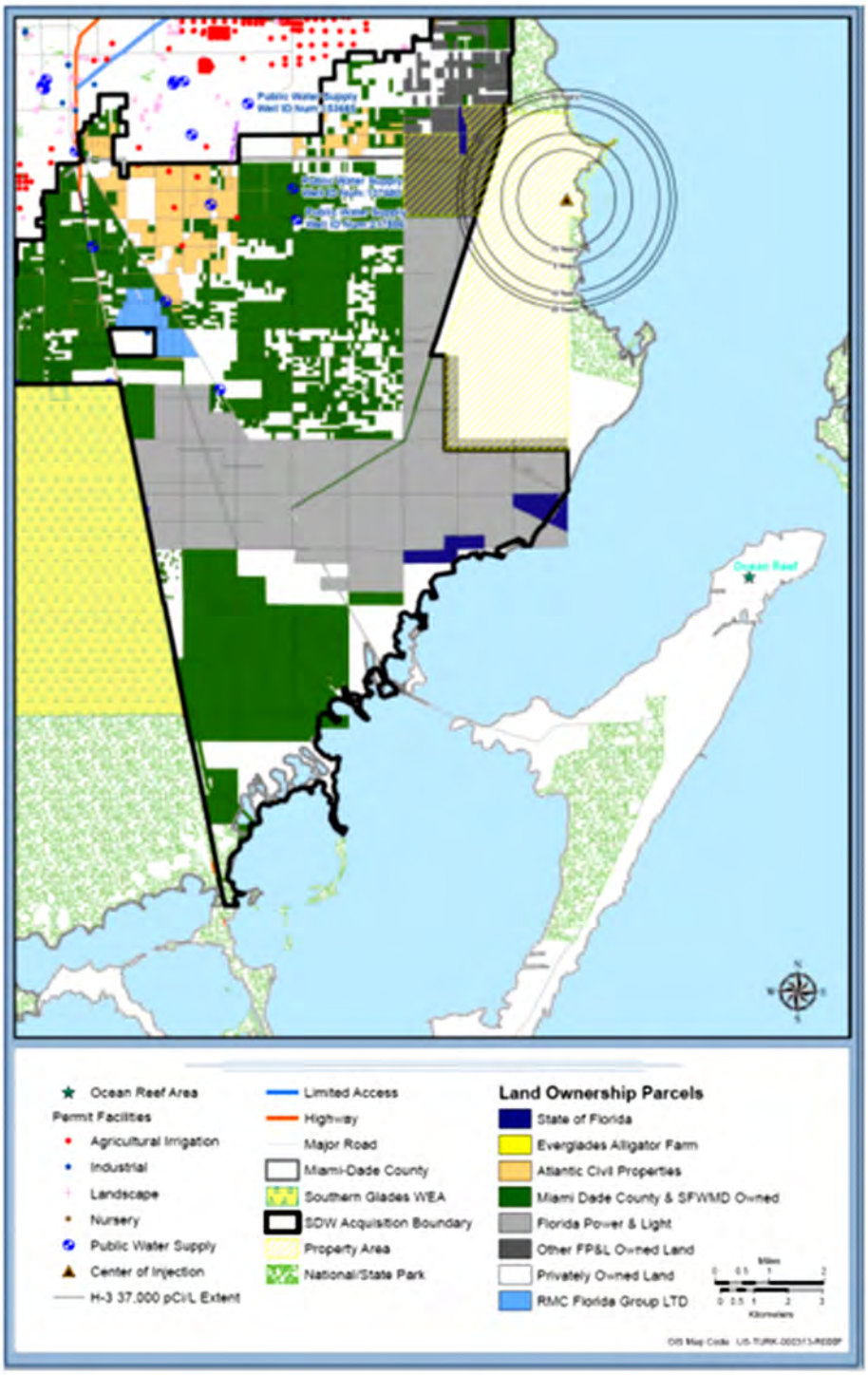
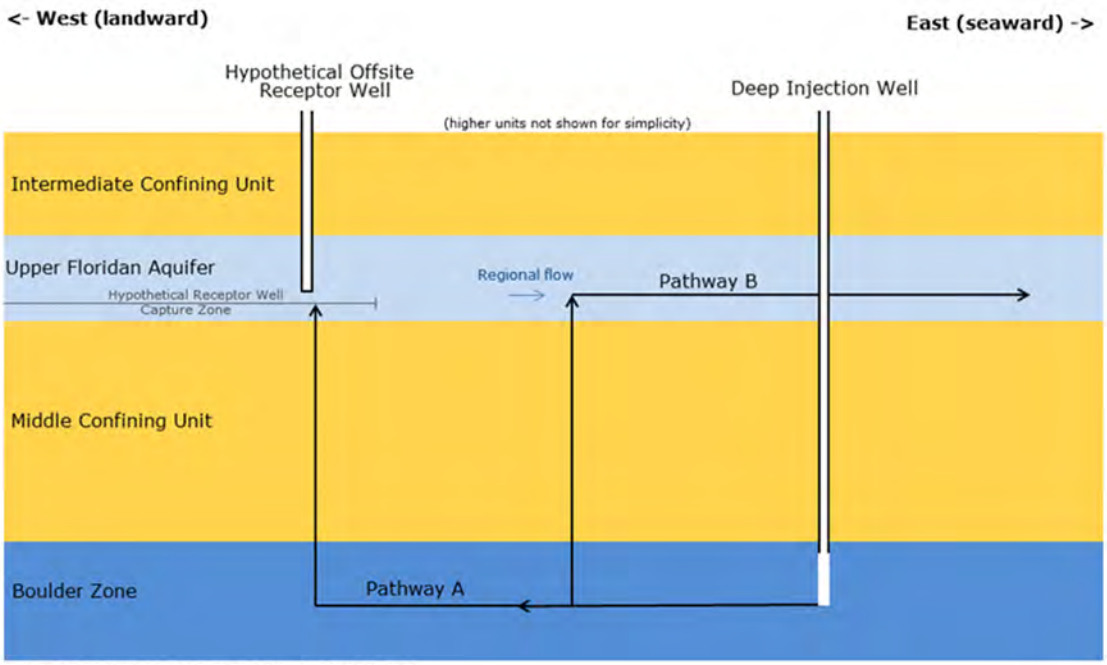


Figure 11.2-212 Land Ownership and Water Supply Well Locations in the Area of Turkey Point



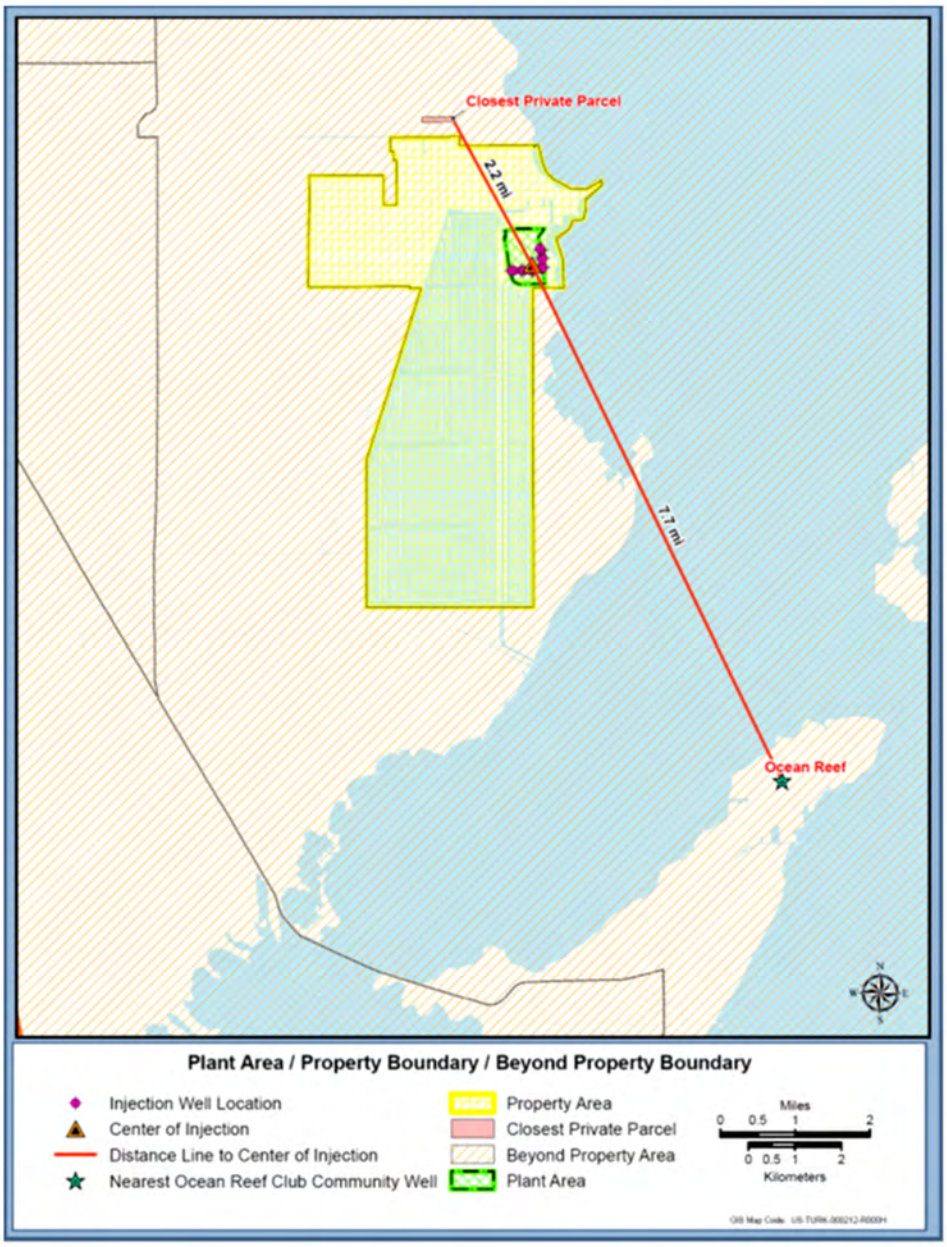
Note: Water supply wells depicted with a specified well ID number are monitoring wells placed along the 2008 USGS salt front line to monitor the Biscayne aquifer for saltwater intrusion.

Figure 11.2-213 Conceptual Schematic of Pathways to Hypothetical Offsite Receptor Accessing the Upper Floridan Aquifer



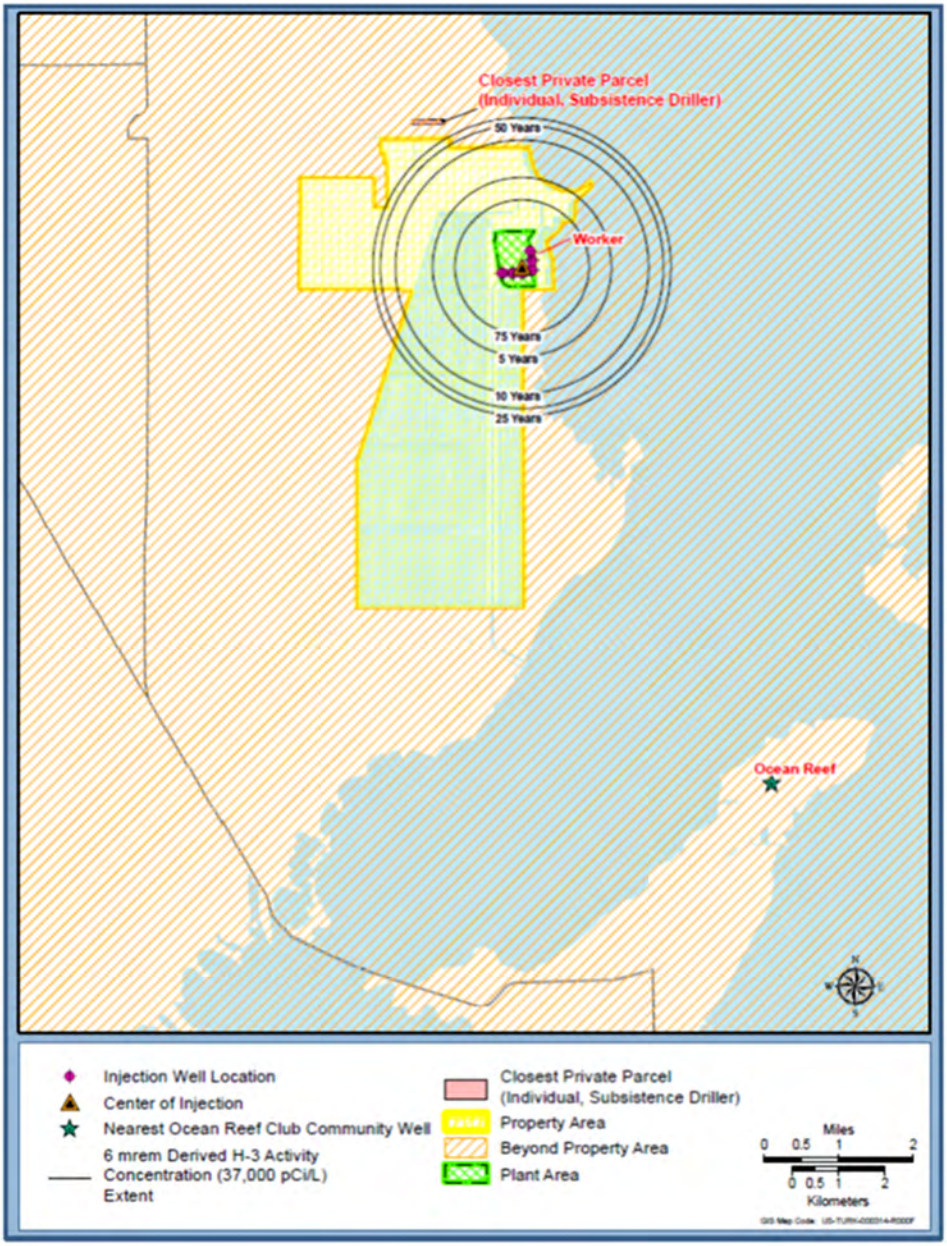
Schematic illustration of potential pathways. Not to scale.

Figure 11.2-214 Proposed Injection Well Field and Hypothesized Receptor Locations



Note: See Figure 11.2-204 for a more detailed view of the injection field.

Figure 11.2-215 Retained Member-of-the-Public Locations



11.3 GASEOUS WASTE MANAGEMENT SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

11.3.3 RADIOACTIVE RELEASES

Add the following new paragraph at the end of DCD Subsection 11.3.3:

STD SUP 11.3-2 There are no gaseous effluent site interface parameters outside of the Westinghouse scope.

11.3.3.2 Estimated Annual Releases

Add the following new paragraph at the end of DCD Subsection 11.3.3.2:

PTN SUP 11.3-1 The effluent concentrations in DCD Table 11.3-4 are based on an atmospheric dispersion factor of 2.0E-05 seconds per cubic meter, as indicated in the table footnotes. The site-specific atmospheric dispersion factor at the site boundary is 3.4E-05 seconds per cubic meter, as shown in Table 2.3.5-202. As concentration is directly proportional to dispersion factor, the concentrations in DCD Table 11.3-4 are multiplied by the ratio of 3.4E-05 to 2.0E-05, a factor of 1.7. The overall fraction of effluent concentration limit for the expected releases increases from the DCD value of 0.030 to the site-specific value of 0.051. This is within the allowable value of 1.0.

11.3.3.4 Estimated Doses

Add the following information at the end of DCD Subsection 11.3.3.4.

PTN COL 11.5-3 The site-specific atmospheric dispersion factor for the site boundary provided in Subsection 2.3.4.2 is bounded by the value given in DCD Table 2-1. Hence, the

single failure of an active component in the gaseous radwaste system yields a whole body dose less than 0.1 rem.

With the annual airborne releases listed in DCD Table 11.3-3, the Units 6 & 7 site specific air doses at ground level at the site boundary are 4.2 mrad for gamma radiation and 18 mrad for beta radiation. These doses are based on the annual average atmospheric dispersion factor from Section 2.3. These doses are below the 10 CFR Part 50, Appendix I design objectives of 10 mrad per year for gamma radiation or 20 mrad per year for beta radiation.

Doses and dose rates to people were calculated using the GASPAR II computer code. This code is based on the methodology presented in the RG 1.109. Factors common to both estimated individual dose rates and estimated population dose are addressed in this subsection. Unique data is addressed in the respective subsections.

Exposure pathways considered for the individual are plume, ground deposition, inhalation, and ingestion of vegetables and meat. Exposure pathways considered for the population are plume, ground deposition, inhalation, and ingestion of vegetables, meat, and milk (both cow and goat).

Based on site meteorological conditions, the highest rate of plume exposure and ground deposition occurs at the site boundary 0.56 kilometers (0.35 miles) south-southeast of the plant (Figure 2.1-204).

The projected population distribution within 81 kilometers (50 miles) of the site in the year 2090 is in Figure 2.1-225.

Agricultural products are estimated from U. S. Department of Agriculture National Agricultural Statistics Service. Vegetable, milk, and meat production data is in Table 11.3-203.

11.3.3.4.1 Estimated Individual Doses

Dose rates to individuals are calculated for airborne decay and deposition, inhalation, and ingestion of meat and vegetables. Because there are no milk animals identified within 5 miles of Units 6 & 7, no dose from ingestion of milk is calculated. Dose from plume and ground deposition are calculated as affecting all age groups equally.

Plume exposure at the site boundary, 0.56 kilometers (0.35 miles) south-southeast of Units 6 & 7, produces a maximum dose rate to a single organ of

13 mrem/year to skin. The maximum total body dose rate was calculated to be 2.6 mrem/year.

Ground deposition at the site boundary, 0.56 kilometers (0.35 miles) south-southeast of Units 6 & 7, produces a maximum dose rate to a single organ of 1.2 mrem/year to skin. The maximum total body dose rate was calculated to be 1.1 mrem/year.

Inhalation dose at the nearest residence, 4.3 kilometers (2.7 miles) north of Units 6 & 7, results in a maximum dose rate to a single organ of 0.014 mrem/year to a child's thyroid. The maximum total body dose rate is calculated to be 0.0012 mrem/year to a teenager.

Vegetable consumption assumes that the dose is received from the nearest garden, 7.7 kilometers (4.8 miles) northwest of the plant. The GASPAR II default vegetable consumption values are used in lieu of site-specific vegetable consumption data as permitted by RG 1.109. The maximum dose rate to a single organ is 0.21 mrem/year to a child's thyroid. The maximum total body dose rate is calculated to be 0.020 mrem/year to a child.

Meat consumption assumes that the dose is received from the nearest meat animal, 4.3 kilometers (2.7 miles) north of Units 6 & 7. The GASPAR II default meat consumption values are used in lieu of site-specific meat consumption data as permitted by RG 1.109. The maximum dose rate to a single organ is 0.018 mrem/year to a child's bone. The maximum total body dose rate is calculated to be 0.0038 mrem/year to a child.

The milk pathway to the individual is not considered because there are no milk animals within 5 miles of Units 6 & 7.

The maximum dose rate to any organ considering every pathway is calculated to be 0.24 mrem/year to a child's thyroid. The maximum total body dose rate is calculated to be 0.038 mrem/year to a child, which includes the pathway doses (meat, vegetable, and inhalation) plus the plume and ground deposition doses (Table 11.3-204). These are below the 10 CFR Part 50, Appendix I design objectives of 5 mrem/year to total body, and 15 mrem/year to any organ, including skin.

Table 11.3-201 contains GASPAR II input data for dose rate calculations. Information regarding the locations for the nearest residence, meat animal, garden, and the site boundary is located in Section 2.3. Table 11.3-204 contains total organ dose rates based on age group. Table 11.3-205 contains total air

doses at each special location. Table 11.3-206 shows the total site doses from Units 6 & 7 as well as the two existing Units 3 & 4 are within the regulatory limits of 40 CFR Part 190.

11.3.3.4.2 Estimated Population Dose

The estimated population dose within 81 kilometers (50 miles) is calculated as 4.0 person-rem total body and 7.5 person-rem thyroid per unit. Table 11.3-207 contains the estimated population doses by nuclide group (noble gases, iodines, particulates, C-14, and H-3).

PTN COL 11.3-1

11.3.3.4.3 Gaseous Radwaste Cost Benefit Analysis Methodology

The methodology of Regulatory Guide 1.110 was used to satisfy the cost benefit analysis requirements of 10 CFR Part 50, Appendix I, Section II.D. The parameters used in calculating the Total Annual Cost (TAC) are fixed and are given for each radwaste treatment system augment listed in Regulatory Guide 1.110, including the Annual Operating Cost (AOC) (Table A-2), Annual Maintenance Cost (AMC) (Table A-3), Direct Cost of Equipment and Materials (DCEM) (Table A-1), and Direct Labor Cost (DLC) (Table A-1). The following variable parameters were used:

- Capital Recovery Factor (CRF) — This factor is taken from Table A-6 of Regulatory Guide 1.110 and reflects the cost of money for capital expenditures. A cost-of-money value of 7 percent per year is assumed in this analysis, consistent with the "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission" (NUREG/BR-0058). A CRF of 0.0806 was obtained from Table A-6.

- Indirect Cost Factor (ICF) — This factor takes into account whether the radwaste system is unitized or shared (in the case of a multi-unit site) and is taken from Table A-5 of RG 1.110. It is assumed that the radwaste system for this analysis is a unitized system at a 2-unit site, which equals an Indirect Cost Factor of 1.625.

- Labor Cost Correction Factor (LCCF) — This factor takes into account the differences in relative labor costs between geographical regions and is taken from Table A-4 of Regulatory Guide 1.110. A factor of 1 (the lowest value) is assumed in this analysis.

The value of $1000 per person-rem is prescribed in Appendix I to 10 CFR Part 50.

The analysis used a conservative assumption that the respective radwaste treatment system augment is a "perfect" system that reduces the effluent and dose by 100 percent. The gaseous radwaste treatment system augment's annual costs were determined and the lowest annual cost considered a threshold value. The lowest-cost option for gaseous radwaste treatment system augments is the Steam Generator Flash Tank Vent to Main Condenser at $6320 per year, which yields a threshold value of 6.32 person-rem total body or thyroid from gaseous effluents.

For AP1000 sites with population dose estimates less than 6.32 person-rem total body or thyroid dose from gaseous effluents, no further cost-benefit analysis is needed to demonstrate compliance with 10 CFR Part 50, Appendix I Section II.D.

11.3.3.4.4 Gaseous Radwaste Cost Benefit Analysis

The Units 6 & 7 population doses are given in Subsection 11.3.3.4.2. The augments provided in RG 1.110 were reviewed and were found not to be cost beneficial in reducing the population dose of 4.0 person-rem total body and 7.5 person-rem thyroid. The lowest cost gaseous radwaste system augment is $6320, which would be $6320/4.0 person-rem total body or $1580 per person-rem total body, and $6320/7.5 person-rem thyroid or $843 per person-rem thyroid. The total body cost per person-rem reduction exceeds the $1000 per person-rem criterion provided in RG 1.110 and is therefore not cost beneficial. Although the cost of thyroid dose reduction is below the threshold, this is assuming the augment completely eliminates the dose. As shown in Table 11.3-207, 2.1 of the 7.5 person-rem thyroid dose is due to noble gases, which will not be mitigated by the Steam Generator Flash Tank Vent to Main Condenser. With the noble gas contribution unaffected by the augment, the cost of thyroid dose reduction is $1170 per person-rem thyroid. Although the cost of $1170 only slightly exceeds the benefit of $1000, this augment is for the addition of a vent to a flash tank that is presumed to exist. Since the AP1000 design does not include a flash tank, the cost of the tank would have to be added to the cost of this augment, further increasing the cost relative to the benefit.

11.3.3.5 Maximum Release Concentrations

Add the following new paragraph at the end of DCD Subsection 11.3.3.5:

PTN SUP 11.3-1 The effluent concentrations in DCD Table 11.3-4 are based on an atmospheric dispersion factor of 2.0E-05 seconds per cubic meter, as indicated in the table footnotes. The site-specific atmospheric dispersion factor at the site boundary is 3.4E-05 seconds per cubic meter, as shown in Table 2.3.5-202. As concentration is directly proportional to dispersion factor, the concentrations in DCD Table 11.3-4 are multiplied by the ratio of 3.4E-05 to 2.0E-05, a factor of 1.7. The overall fraction of effluent concentration limit for the maximum releases increases from the DCD value of 0.33 to the site-specific value of 0.56. This is within the allowable value of 1.0.

11.3.3.6 Quality Assurance

Add the following to the end of DCD Subsection 11.3.3.6:

STD SUP 11.3-1 Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation, and testing provisions of the gaseous radwaste system is established by procedures that complies with the guidance presented in Regulatory Guide 1.143.

PTN SUP 11.3-1 The quality assurance program for design, construction, procurement, materials, welding, fabrication, inspection and testing activities conforms to the quality control provisions of the codes and standards recommended in Table 1 of Regulatory Guide 1.143.

11.3.5 COMBINED LICENSE INFORMATION

11.3.5.1 Cost Benefit Analysis of Population Doses

PTN COL 11.3-1 This COL Item is addressed in Subsections 11.3.3.4.3 and 11.3.3.4.4.

PTN COL 11.5-3 This COL Item is addressed in Subsection 11.3.3.2.

11.3.6 REFERENCES

201. Florida Power & Light Company, *2010 Annual Radiological Environmental Operating Report,* Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML11140A084, April 2011.

202. National Agricultural Statistics Service, *Florida Annual Statistical Bulletin* 2008. Available at http://www.nass.usda.gov/Statistics_by _State/Florida/ Publications/ AnnuaL Statistical_Bulletin/fasb08p.htm, accessed August 27, 2013.

203. U.S. Department of Agriculture, *Commercial Red Meat: Production, by State and U.S.*, National Agricultural Statistics Bulletin. Available at http:// www.nass.usda.gov/Statistics_by Statellowa/Publicationsl Annual_ Statistical_ Bulletin/2007107 1 02.pdf, accessed August 27, 2013.

204. U.S. Department of Agriculture, *2002 Census of Agriculture*, Florida State and County Data, Vol. 1, June 2004. Available at www.nass.usda.gov/ Publications/2002/index.php, accessed August 27, 2013.

205. Florida Power & Light Company, *Annual Radioactive Effluent Release Report*, *January 2004 through December 2004,* Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML050960370, March 2005.

206. Florida Power & Light Company, *Annual Radioactive Effluent Release Report*, *January 2005 through December 2005,* Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML060940646, March 2006.

207. Florida Power & Light Company, *Annual Radioactive Effluent Release Report*, January *2006 through December 2006,* Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML070920509, March 2007.

208. Florida Power & Light Company, *Annual Radioactive Effluent Release Report, January 2007 through December 2007*, Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML080940605, March 2008.

209. Florida Power & Light Company, *Annual Radioactive Effluent Release Report, January 2008 through December 2008*, Turkey Point Units 3 & 4, U.S. NRC ADAMS Accession No. ML090760628, February 2009.

PTN COL 11.3-1

PTN COL 11.5-3

Table 11.3-201
GASPAR II Input

Input Parameter	Value
Number of Source Terms	1
Source Term	DCD Table 11.3-3
Population Data	Table 11.3-202
Fraction of the year leafy vegetables are grown	1.0
Fraction of the year milk cows are on pasture	1.0[(a)]
Fraction of max individual's vegetable intake from own garden	0.76
Fraction of the year goats are on pasture	1.0
Fraction of goat feed intake from pasture while on pasture	1.0
Fraction of the year beef cattle are on pasture	1.0
Fraction of beef-cattle feed intake from pasture while on pasture	1.0
Total Production Rate for the 50-mile area	
– Vegetables (kg/yr)	Table 11.3-203
– Milk (l/yr)	Table 11.3-203
– Meat (kg/yr)	Table 11.3-203
Special Location Data	FSAR Section 2.3.5

(a) There are no mi k animals identified within 5 miles of Units 6 & 7 (Reference 201).

PTN COL 11.3-1

PTN COL 11.5-3

Table 11.3-202
Population Distribution in 2090

Direction	Distance (miles)									
	0–1	1–2	2–3	3–4	4–5	5–10	10–20	20–30	30–40	40–50
S	—	—	—	—	—	76	1,749	19	—	—
SSW	—	—	—	—	—	12	361	7,598	4,811	893
SW	—	—	—	—	—	—	—	—	—	12
WSW	—	—	—	—	—	207	450	41	—	2
W	—	—	—	—	—	38,378	12,086	—	—	—
WNW	—	—	—	—	—	121,964	40,618	—	9	5
NW	—	—	—	8	8	86,987	21,406	78	797	26
NNW	—	—	12	—	—	60,646	480,443	248,964	153	30
N	2,872	—	4,698	—	—	44,579	419,603	957,596	1,048,495	717,732
NNE	—	—	—	—	—	—	11,133	828,933	809,459	302,611
NE	—	—	—	—	—	—	30	—	—	—
ENE	—	—	—	—	—	6	—	—	—	—
E	—	—	—	—	—	—	—	—	—	—
ESE	—	—	—	—	—	—	—	—	—	—
SE	—	—	—	—	—	84	—	—	—	—
SSE	—	—	—	—	—	6,748	—	—	—	—
Total	2,872	0	4,710	8	8	359,687	987,879	2,043,229	1,863,724	1,021,311
									Grand Tota	6,283,428

Note: Based on Figures 2.1-215 and 2.1-225.

PTN COL 11.3-1

Table 11.3-203
Vegetable, Milk, and Meat Production Data

PTN COL 11.5-3

Food[a]	State Production[b]				Production Basis[c]			50-Mile Fraction[d]	50-Mile Production[e]			
					Measure	State	50-mile		Current		2090	
Red Meat	6.67E+07	lbm	3.03E+07	kg	No. of beef cows	9.82E+05	2.01E+03	2.05E–03	6.19E+04	kg	1.12E+05	kg
Broilers	4.25E+08	lbm	1.93E+08	kg	No. of broilers	1.97E+07	3.44E+02	1.74E–05	3.36E+03	kg	6.09E+03	kg
Milk	2.11E+08	lbm	9.57E+07	L	No. of milk cows	1.45E+05	6.60E+01	4.56E–04	4.36E+04	L	7.89E+04	L
Vegetables	5.18E+07	cwt	2.35E+09	kg	Harvested acres	2.31E+06	5.95E+04	2.57E–02	6.04E+07	kg	1.09E+08	kg

(a) Meat Production — in calculating population doses, the red meat and broiler values are added to conservatively estimate the total meat production.

(b) State Production — The production rates are converted into units of kilograms (1 cwt = 100 bm = 45.36 kg); milk density is assumed to be 1 kilogram/liter. State production values are from U.S. Department of Agriculture:
Broilers, milk and vegetables — *Florida Annual Statistical Bulletin 2008*, National Agricultural Statistics Service, http://www.nass.usda.gov/Statistics_by_State/Florida/Publications/Annual_Statistical_Bulletin/fasd08p.htm. (Reference 202)
Red meat — *Commercial Red Meat: Production, by State and U.S.*, U.S. Department of Agriculture, National Agricultural Statistics Bulletin, p. 102, http://www.nass.usda.gov/Statistics_by_State/Iowa/Publications/Annual_Statistical_Bulletin/2007/07_102.pdf. (Reference 203)

(c) Production Basis — The production bases for the state and the four counties (Broward, Collier, Dade, and Monroe) within 50 miles of the plant. The production values are from U.S. Department of Agriculture:
2002 Census of Agriculture, Florida State and County Data, Volume 1, U.S. Department of Agriculture, June 2004, www.nass.usda.gov/census/census02/volume1/fl/FLVolume104.pdf. (Reference 204)

(d) 50-Mile Fraction — The fraction of production within 50 miles is obtained by dividing the 50-mile value by the state value.

(e) 50-Mile Production — The current 50-mile production is obtained by multiplying the state production by the 50-mile fraction. The 2090 production is obtained by multiplying the current production by 1.81, representing the population increase from 3,464,756 in 2010 to 6,283,428 in 2090.

PTN COL 11.5-3

Table 11.3-204
Individual Dose Rates

Location[a]	Pathway		Dose Rate per Unit (mrem/yr)[b]							
			Total Body	GI-Tract	Bone	Liver	Kidney	Thyroid	Lung	Skin
Residence 2.7 mi N	External	Plume	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0074	0.046
		Ground	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0077
		Total	0.013	0.013	0.013	0.013	0.013	0.013	0.014	0.053
	Inhalation	Adult	0.0012	0.0012	0.00016	0.0012	0.0012	0.0096	0.0015	0
		Teen	0.0012	0.0012	0.00019	0.0012	0.0012	0.012	0.0016	0
		Child	0.0010	0.0010	0.00023	0.0011	0.0011	0.014	0.0014	0
		Infant	0.00059	0.00058	0.00012	0.00063	0.00063	0.012	0.00087	0
Garden 4.8 miles NW	Vegetable	Adult	0.0064	0.0065	0.033	0.0064	0.0061	0.086	0.0055	0
		Teen	0.0092	0.0093	0.050	0.0096	0.0091	0.11	0.0083	0
		Child	0.020	0.019	0.11	0.021	0.020	0.21	0.018	0
Meat Animal 2.7 miles N	Meat	Adult	0.0026	0.0036	0.011	0.0027	0.0026	0.0094	0.0025	0
		Teen	0.0021	0.0027	0.0095	0.0022	0.0021	0.0070	0.0020	0
		Child	0.0038	0.0040	0.018	0.0039	0.0038	0.011	0.0037	0
MEI[c] — Sum of Residence, Garden, Meat Animal	All	Adult	0.023	0.025	0.058	0.023	0.023	0.12	0.023	0.053
		Teen	0.026	0.026	0.073	0.026	0.026	0.14	0.026	0.053
		Child	0.038	0.037	0.15	0.039	0.038	0.24	0.037	0.053
		Infant	0.014	0.014	0.013	0.014	0.014	0.025	0.015	0.053

(a) Locations are from Table 2.3.5-202.
(b) 10 CFR 50 Appendix I: Total body dose limit = 5 mrem/year, skin dose = 15 mrem/year, and dose to any organ = 15 mrem/year.
(c) MEI dose rates represent the summation of dose rates from each pathway (plume, ground, inhalation, vegetable, and meat). There are no milk animals identified within 5 miles of Units 6 & 7 (Reference 201).

PTN COL 11.5-3

Table 11.3-205
Doses in Millirads at Special Locations per Unit

Special Location	Beta Air Dose	Gamma Air Dose
Site Boundary[(a)]	18	4.2
Nearest Residence/Meat Animal	0.068	0.012
Nearest Vegetable Garden	0.048	0.0099

(a) 10 CFR 50 Appendix I Design Objective: Gamma Air Dose = 10 mrad and Beta Air Dose = 20 mrad.

PTN COL 11.5-3

Table 11.3-206
Comparison of Individual Doses with 40 CFR 190 Criteria

	Dose (mrem/yr)			
	Units 6 & 7[(a)]	Units 3 & 4[(b)]	Site Total	Limit
Total Body	7.8	0.0029	7.8	25
Thyroid	15	0.0059	15	75
Other Organ - Lung	8.4	0.0059	8.4	25

(a) Site boundary doses from a single new unit are doubled.
(b) Doses are due to liquid and gaseous effluents. The dose due to direct radiation is negligible, as exposure rates from the plant are consistent with those observed during the preoperational surveillance program (Reference 201). Effluent doses are taken as the maximum over a 5-year period, as reported in the annual effluent reports (References 205 to 209). Since the annual reports do not include plume contribution, the maximum gamma air dose is added to the total body and thyroid doses and the maximum beta air dose is added to the skin dose. Lung dose is assumed to be the same as thyroid dose.

PTN COL 11.5-3

Table 11.3-207
Estimated Population Doses per Unit

	Dose (person-rem/yr)	
	Total Body	Thyroid
Noble Gases	2.1	2.1
Iodines	0.013	3.5
Particulates	1.2	1.2
C-14	0.21	0.21
H-3	0.48	0.48
Total	4.0	7.5

11.4 SOLID WASTE MANAGEMENT

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

11.4.2 SYSTEM DESCRIPTION

Add the following information after DCD Subsection 11.4.2.4.2:

11.4.2.4.3 Contingency Plans for Temporary Storage of Low-Level Radioactive Waste (LLW)

PTN SUP 11.4-2 In the event that offsite shipping of radwaste is not available when Units 6 & 7 become operational, temporary storage capability is available on site for greater than two years at the expected rate of radwaste generation and greater than one year at the maximum rate of radwaste generation, as described in DCD Subsection 11.4.2.1 paragraph ten. Implementation of waste minimization strategies could extend the duration of temporary radwaste storage capability.

If additional onsite radwaste storage capability were required, then onsite facilities would be designed, constructed, and operated in accordance with the design guidance provided in NUREG-0800, Standard Review Plan Chapter 11 Radioactive Waste Management Appendix 11.4-A, Design Guidance for Temporary Storage of Low-Level Radioactive Waste.

11.4.5 QUALITY ASSURANCE

Add the following information to the end of DCD Subsection 11.4.5:

STD SUP 11.4-1 Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation and testing provisions of the solid radwaste system is established by procedures that complies with the guidance presented in Regulatory Guide 1.143.

PTN SUP 11.4-2 The quality assurance program for design, construction, procurement, materials, welding, fabrication, inspection and testing activities conforms to the quality control provisions of the codes and standards recommended in Table 1 of Regulatory Guide 1.143.

11.4.6 COMBINED LICENSE INFORMATION FOR SOLID WASTE MANAGEMENT SYSTEM PROCESS CONTROL PROGRAM

Add the following information to the end of DCD Subsection 11.4.6.

This COL Item is addressed below.

STD COL 11.4-1 A Process Control Program (PCP) is developed and implemented in accordance with the recommendations and guidance of NEI 07-10A (Reference 201). The PCP describes the administrative and operational controls used for the solidification of liquid or wet solid waste and the dewatering of wet solid waste. Its purpose is to provide the necessary controls such that the final disposal waste product meets applicable federal regulations (10 CFR Parts 20, 50, 61, 71, and 49 CFR Part 173), state regulations, and disposal site waste form requirements for burial at a low level waste (LLW) disposal site that is licensed in accordance with 10 CFR Part 61.

PTN COL 11.4-1 When the disposable media is removed from mobile radwaste processing system, the process control program is utilized to move the media from the system and place the media into a package suitable for shipping. The mobile radwaste processing system is not placed back into service until the media that has been removed is packaged and ready for shipment.

STD COL 11.4-1 Waste processing (solidification or dewatering) equipment and services may be provided by the plant or by third-party vendors. Each process used meets the applicable requirements of the PCP.

No additional onsite radwaste storage is required beyond that described in the DCD.

Table 13.4-201 provides milestones for PCP implementation.

PTN SUP 11.4-1 Low-level radioactive waste is packaged to meet transportation and disposal site acceptance requirements. Packaging of waste for offsite shipment complies with applicable DOT (49 CFR Parts 173 and 178) and NRC regulations (10 CFR Part 71) for transportation of radioactive material. The packaged waste is stored on site on an interim basis before being shipped offsite to a licensed processing, storage, or disposal facility. Onsite storage for more than a year at the maximum rate of generation is provided in the waste accumulation room of the radwaste building. Radioactive waste is shipped offsite by truck.

Consistent with current commercial agreements, a third-party contractor processes, stores, owns, and ultimately disposes of low-level waste generated as a result of operations. Activities associated with the transportation, processing, and ultimate disposal of low-level waste comply with applicable laws and regulations in order to ensure the public's health and safety. In particular, the third-party contractor conducts its operations consistent with NRC regulations (e.g., 10 CFR Part 20).

All packaged and stored radwaste is shipped to offsite disposal/storage facilities and temporary storage of radwaste is only provided until routine offsite shipping can be performed. Accordingly, there is no expected need for permanent onsite storage facilities at Units 6 & 7.

If additional storage capacity for Class B and C waste were required, further temporary storage would be designed, constructed, and operated in accordance with the design guidance provided in NUREG-0800, Standard Review Plan 11.4, Appendix 11.4-A. The change to the facility to provide additional onsite storage would be evaluated by performing written safety analyses in accordance with 10 CFR 50.59. If the acceptability of the proposed additional storage could not be demonstrated by 10 CFR 50.59 analyses, a license amendment would be sought to approve the proposed storage.

11.4.6.1 Procedures

STD SUP 11.4-1 Operating procedures specify the processes to be followed to ship waste that complies with the waste acceptance criteria (WAC) of the disposal site, 10 CFR 61.55 and 61.56, and the requirements of third party waste processors.

Each waste stream process is controlled by procedures that specify the process for packaging, shipment, material properties, destination (for disposal or further processing), testing to verify compliance, the process to address non-conforming materials, and required documentation.

Where materials are to be disposed of as non-radioactive waste (as described in DCD Subsection 11.4.2.3.3), final measurements of each package are performed to verify there has not been an accumulation of licensed material resulting from a buildup of multiple, non-detectable quantities. These measurements are obtained using sensitive scintillation detectors, or instruments of equal sensitivity, in a low-background area.

Procedures document maintenance activities, spill abatement, upset condition recovery, and training.

Procedures document the periodic review and revision, as necessary, of the PCP based on changes to the disposal site, WAC regulations, and third party PCPs.

11.4.6.2 Third Party Vendors

Third party equipment suppliers and/or waste processors are required to supply approved PCPs. Third party vendor PCPs describe compliance with Regulatory Guide 1.143, Generic Letter 80-09, and Generic Letter 81-39. Third party vendor PCPs are referenced appropriately in the plant PCP before commencement of waste processing.

11.4.7 REFERENCES

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201. Nuclear Energy Institute, *Generic FSAR Template Guidance for Process Control Program (PCP)*, NEI 07-10A, Rev. 0, NRC ADAMS Accession No. ML091460627, March 2009.

202. Not Used.

203. Not Used.

204. Not Used.

205. Not Used.

11.5 RADIATION MONITORING

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

11.5.1.1 Safety Design Basis

Revise the third and fourth bullets in the third paragraph of DCD Subsection 11.5.1.1 to read as follows:

PTN DEP 6.4-1

- Initiate main control room supplemental filtration in the event of abnormally high particulate, iodine, or gaseous radioactivity in the main control room supply air (High-1)
- Initiate main control room ventilation isolation and actuate the main control room emergency habitability system in the event of abnormally high particulate or iodine radioactivity in the main control room supply air (High-2)

11.5.1.2 Power Generation Design Basis

Revise the fourth bullet in DCD Subsection 11.5.1.2 as follows:

PTN COL 11.5-2

- Data collection and data storage to support compliance reporting for the applicable NRC requirements and guidelines, such as General Design Criterion 64 and Regulatory Guide 1.21 and Regulatory Guide 4.15, Revision 2.

11.5.2.3.1 Fluid Process Monitors

Revise the second to last sentence of the first paragraph of the Main Control Room Supply Air Duct Radiation Monitors section of DCD Subsection 11.5.2.3.1 to read as follows:

PTN DEP 6.4-1

When predetermined setpoints are exceeded, the monitors provide signals to initiate the supplemental air filtration system on a High-1 gaseous, particulate, or iodine concentration, and to isolate the main control room air intake and exhaust

ducts and activate the main control room emergency habitability system on High-2 particulate or iodine concentrations.

11.5.2.4 Inservice Inspection, Calibration, and Maintenance

Add the following information at the end of DCD Subsection 11.5.2.4:

STD COL 11.5-2 Daily checks of effluent monitoring system operability are made by observing channel behavior. Detector response is routinely observed with a remotely-positioned check source in accordance with plant procedures. Instrument background count rate is also observed to determine proper functioning of the monitors. Any detector whose response cannot be verified by observation during normal operation or by using the remotely-positioned check source can have its response checked with a portable check source. A record is maintained showing the background radiation level and the detector response.

Calibration of the continuous radiation monitors is done with commercial radionuclide standards that have been standardized using a measurement system traceable to the National Institute of Standards and Technology.

11.5.3 EFFLUENT MONITORING AND SAMPLING

Add the following information at the end of DCD Subsection 11.5.3.

PTN COL 11.5-2 Units 6 & 7 use the existing fleet program for quality assurance of radiological effluent and environmental monitoring that is based on RG 4.15, Revision 2.

PTN SUP 11.5-1 The effluent from the reclaimed water treatment facility (RWTF) is monitored for measurable quantities of unregulated radioactive material. If present, a fraction of this radioactive material would be adsorbed in RWTF treatment sludge and another fraction would remain in the treated RWTF effluent as circulating water supply. The RWTF sludge fraction is characterized as required to demonstrate compliance with the waste acceptance criteria established by the commercial sludge disposal facility, as well as applicable transportation regulations. The RWTF effluent fraction, including some end products of processing that may be

bypassed to the plant blowdown sump (as warranted by operational conditions), is characterized to enable its differentiation from radioactive material attributed to Units 6 & 7 operations (to ensure the reporting of deep well injection system discharge quantities and dose solely reflects Units 6 & 7 radioactive material).

The Units 6 & 7 ODCM developed and made available for NRC inspection prior to fuel load describes the sampling, monitoring, analysis, and assessment of the RWTF effluent as it relates to reporting deep well injection system discharge quantities and doses.

The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, Effluent Concentration Limits, by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum DF. The required minimum DF is calculated and applied before the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 ODCM, an operational program identified in Table 13.4-201.

11.5.4 PROCESS AND AIRBORNE MONITORING AND SAMPLING

Add the following information at the end of the first paragraph in DCD Subsection 11.5.4.

PTN COL 11.5-2 The sampling program for liquid and gaseous effluents will conform to RG 4.15, Revision 2 (see Appendix 1AA).

Add the following information at the end of DCD Subsection 11.5.4.

11.5.4.1 Effluent Sampling

STD COL 11.5-2 Effluent sampling of potential radioactive liquid and gaseous effluent paths is conducted on a periodic basis to verify effluent processing meets the discharge limits to offsite areas. The effluent sampling program provides the information for the effluent measuring and reporting required by 10 CFR 50.36a and 10 CFR Part 20 and implemented through the Offsite Dose Calculation Manual (ODCM)

and plant procedures. The frequency of the periodic sampling and analyses described herein are nominal and may be increased as permitted by procedure. Tables 11.5-201 and 11.5-202 summarize the sample and analysis schedules and sensitivities, respectively. The information contained in Tables 11.5-201 and 11.5-202 are derived from Regulatory Guide 1.21.

Laboratory isotopic analyses are performed on continuous and batch effluent releases in accordance with the ODCM. Results of these analyses are compiled and appropriate portions are utilized to produce the Radioactive Effluent Release Report.

11.5.4.2 Representative Sampling

Representative samples are obtained from well-mixed stream of volumes of effluent liquid through the use of proper sampling equipment, proper location of sampling points, and the development and use of sampling procedures. The recommendations of ANSI N 42.18 (Reference 203) are considered for the selection of instrumentation specific to the continuous monitoring of radioactivity in liquid effluents.

Sampling of effluent liquids is consistent with guidance in Regulatory Guide 1.21. When practical, effluent releases are batch-controlled, and prior to sampling, large volumes of liquid waste are mixed, in as short a time span as practicable, so that solid particulates are uniformly distributed in the liquid volume. Sampling and analysis is performed, and release conditions set, before release. Sample points are located to minimize flow disturbance due to fittings and other characteristics of equipment and components. Sample lines are flushed consistent with plant procedures to remove sediment deposits.

Representative sampling of process effluents is attained through sample and monitor locations and methods and criteria detailed in plant procedures.

Composite sampling is employed to analyze for hard to measure radionuclides and to monitor effluent streams that normally are not expected to contain significant amounts of radioactive contamination. Composite liquid samples are collected in proportion to the volume of each batch of effluent release. The composite is thoroughly mixed prior to analysis. Collection periods for composites are as short as practicable and periodic checks are performed to identify changes in composite samples. When grab samples are collected instead of composite samples, the time of the sample, location, and frequency are considered to provide a representative sample of the radioactive materials.

The pressure head of the fluid, if available, is used for taking samples. If sufficient pressure head is not available to take samples, then sample pumps are used to draw the sample from the process fluid to the detector panels and back to the process.

Testing and obtaining representative samples using the radiation monitors described in DCD Subsection 11.5 will be performed in accordance with ANSI N13.1 (Reference 201).

For obtaining representative samples in unfiltered ducts, isokinetic probes are tested and used as recommended by ANSI N13.1 (Reference 201).

Analytical Procedures

Typically, samples of process and effluent gases and liquids are analyzed in the station laboratory or by an outside laboratory via the following techniques:

- Gross alpha/beta counting
- Gamma spectrometry
- Liquid scintillation counting

"Available" instrumentation and counting techniques change as other instruments and techniques become available. For this reason, the frequency of sampling and the analysis of samples are generalized in this subsection.

Gross alpha/beta analysis may be performed directly on unprocessed samples (e.g., air filters) or on processed samples (e.g., evaporated liquid samples). Sample volume, counting geometry, and counting time are chosen to match measurement capability with sample activity. Correction factors for sample detector geometry, self-absorption and counter resolving time are applied to provide the required accuracy.

Liquid effluent samples are prepared for alpha/beta counting by evaporation onto steel planchets. Gamma analysis may be done on any type of sample (gas, solid or liquid) in a gamma spectrometer.

Tritiated water vapor samples are collected by condensation or adsorption, and the resultant liquid is analyzed by liquid scintillation counting techniques.

Radiochemical separations are used for the routine analysis of Sr-89 and Sr-90.

Liquid samples are collected in polyethylene bottles to minimize absorption of nuclides onto container walls.

11.5.6.5 Quality Assurance

Add the following information at the end of DCD Subsection 11.5.6.5.

PTN COL 11.5-2 The sampling program and the associated monitors conform to RG 4.15, Revision 2 (see Appendix 1AA).

11.5.8 COMBINED LICENSE INFORMATION

STD COL 11.5-1 An Offsite Dose Calculation Manual (ODCM) is developed and implemented in accordance with the recommendations and guidance of NEI 07-09A (Reference 202). The ODCM contains the methodology and parameters used for calculating doses resulting from liquid and gaseous effluents. The ODCM addresses operational setpoints, including planned discharge rates, for radiation monitors and monitoring programs (process and effluent monitoring and environmental monitoring) for the control and assessment of the release of radioactive material to the environment. The ODCM provides the limitations on operation of the radwaste systems, including functional capability of monitoring instruments, concentrations of effluents, sampling, analysis, 10 CFR Part 50, Appendix I dose and dose commitments, and reporting. The ODCM will be finalized prior to fuel load with site-specific information.

PTN SUP 11.5-2 The site-specific conditions addressed in the ODCM include information addressing the deep injection wells, describe methods that are used in controlling and monitoring discharges of liquid effluents via deep injection wells, and describe how water samples are collected and sampled from each dual zone monitoring well. Also addressed are well development and purging, containment and processing of purged well water, and sample processing including sample collection, sample preservation, and quality control.

STD COL 11.5-1 Table 13.4-201 provides milestones for ODCM implementation.

PTN COL 11.5-1 Formal administrative controls will be implemented by the licensees of Turkey Point Units 6 & 7 and Turkey Point Units 3 & 4 coordinating their direct radiation contributions and liquid and gaseous effluent release concentrations so that applicable site-allocated dose and dose rate limits (10 CFR 20 and 40 CFR 190) are not exceeded. These administrative controls will be incorporated into each licensee's procedures controlling direct radiation and effluent releases for normal operations and anticipated operational occurrences. The administrative controls and coordination process will be described in the ODCM.

STD COL 11.5-2 This COL Item is addressed in Subsections 11.5.2.4, 11.5.4.1, 11.5.4.2.

PTN COL 11.5-2 This COL Item is addressed in Subsections 11.5.1.2, 11.5.3, 11.5.4, and 11.5.6.5.

PTN COL 11.5-3 This COL Item is addressed in Subsection 11.2.3.5 and 11.3.3.2 for liquid and gaseous effluents, respectively.

Add the following subsection after DCD Subsection 11.5.8.

11.5.9 REFERENCES

201. American National Standards Institute, *Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities*, ANSI N13.1-1969.

202. Nuclear Energy Institute, *Generic FSAR Template Guidance for Offsite Dose Calculation Manual (ODCM) Program Description*, NEI 07-09A, Rev. 0, NRC ADAMS Accession No. ML091050234, March 2009.

203. American National Standards Institute, *Specification and Performance of On-Site Instrumentation for Continuous Monitoring Radioactivity in Effluents*, ANSI N42.18-2004.

STD COL 11.5-2

Table 11.5-201
Minimum Sampling Frequency

Stream	Sampled Medium	Frequency
Gaseous	Continuous Release	A sample is taken within one month of initial criticality, and at least weekly thereafter to determine the identity and quantity for principal nuclides being released. A similar analysis of samples is performed following each refueling, process change, or other occurrence that could alter the mixture of radionuclides.
		When continuous monitoring shows an unexplained variance from an established norm.
		Monthly for tritium.
	Batch Release	Prior to release to determine the identity and quantity of the principal radionuclides (including tritium).
	Filters (particulates)	Weekly.
		Quarterly for Sr-89 and Sr-90.
		Monthly for gross alpha.
Liquid	Continuous Releases	Weekly for principal gamma-emitting radionuclides.
		Monthly, a composite sample for tritium and gross alpha.
		Monthly, a representative sample for dissolved and entrained fission and activation gases.
		Quarterly, a composite sample for Sr-89, Sr-90, and Fe-55.
	Batch Releases	Prior to release for principal gamma-emitting radionuclides.
		Monthly, a composite sample for tritium and gross alpha.
		Monthly, a representative sample from at least one representative batch for dissolved and entrained fission and activation gases.
		Quarterly, a composite sample for Sr-89, Sr-90 and Fe-55.

STD COL 11.5-2

Table 11.5-202
Minimum Sensitivities

Stream	Nuclide	Sensitivity
Gaseous	Fission & Activation Gases	1.0E-04 µCi/cc
	Tritium	1.0E-06 µCi/cc
	Iodines & Particulates	Sufficient to permit measurement of a small fraction of the activity that would result in annual exposures of 15 mrem to thyroid for iodines, and 15 mrem to any organ for particulates, to an individual in an unrestricted area.
	Gross Radioactivity	Sufficient to permit measurement of a small fraction of the activity that would result in annual air dose of 1) 10 mrad due to gamma, and 2) 20 mrad of beta at any location near ground level at or beyond the site boundary.
Liquid	Gross Radioactivity	1.0E-07 µCi/ml
	Gamma-emitters	5.0E-07 µCi/ml
	Dissolved & Entrained Gases	1.0E-05 µCi/ml
	Gross Alpha	1.0E-07 µCi/ml
	Tritium	1.0E-05 µCi/ml
	Sr-89 & Sr-90	5.0E-08 µCi/ml
	Fe-55	1.0E-06 µCi/ml

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CHAPTER 12 RADIATION PROTECTION

12.1 ASSURING THAT OCCUPATIONAL RADIATION EXPOSURES ARE AS-LOW-AS-REASONABLY ACHIEVABLE (ALARA)

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

STD COL 12.1-1 This section incorporates by reference NEI 07-08A, Generic FSAR Template Guidance for Ensuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable (ALARA), Revision 0. See Table 1.6-201. ALARA practices are developed in a phased milestone approach as part of the procedures necessary to support the Radiation Protection Program. Table 13.4-201 describes the major milestones for ALARA procedures development and implementation.

Revise the last sentence of NEI 07-08A Subsection 12.1.2 to read:

STD COL 12.1-1 ALARA procedures are established, implemented, maintained and reviewed consistent with 10 CFR 20.1101 and the quality assurance criteria described in Part III of the Quality Assurance Program Description, which is discussed in Section 17.5.

Add the following information at the end of DCD Subsection 12.1.2.4:

12.1.2.4.3 Equipment Layout

STD SUP 12.1-1 A video record of the equipment layout in areas where radiation fields are expected to be high following operations may be used to assist in ALARA planning and to facilitate decommissioning.

12.1.3 COMBINED LICENSE INFORMATION

STD COL 12.1-1 This COL item is addressed in NEI 07-08A and Appendix 12AA.

12.2 RADIATION SOURCES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

12.2.1.1.10 Miscellaneous Sources

Add the following information at the end of DCD Subsection 12.2.1.1.10:

STD COL 12.2-1 Licensed sources containing byproduct, source, and special nuclear material that warrant shielding design consideration meet the applicable requirements of 10 CFR Parts 20, 30, 31, 32, 33, 34, 40, 50, and 70.

There are byproduct and source materials with known isotopes and activity manufactured for the purpose of measuring, checking, calibrating, or controlling processes quantitatively or qualitatively.

These sources include but are not limited to:

- Sources in field monitoring equipment.
- Sources in radiation monitors to maintain a threshold sensitivity.
- Sources used for radiographic operations.
- Depleted uranium slabs used to determine beta response and correction factors for portable monitoring instrumentation.
- Sources used to calibrate and response check field monitoring equipment (portable and fixed).
- Liquid standards and liquids or gases used to calibrate and verify calibration of laboratory counting and analyzing equipment.
- Radioactive waste generated by the use of radioactive sources.

Specific details of these sources are maintained in a database on-site following procurement. This database, at a minimum, contains the following information:

- Isotopic composition
- Location in the plant
- Source strength
- Source geometry

Written procedures are established and implemented that address procurement, receipt, inventory, labeling, leak testing, surveillance, control, transfer, disposal, storage, issuance and use of these radioactive sources. These procedures are developed in accordance with the radiation protection program to comply with 10 CFR Parts 19 and 20. A supplementary warning symbol is used in the presence of large sources of ionizing radiation consistent with the guidance in Regulatory Issue Summary (RIS) 2007-03.

Sources maintained on-site for instrument calibration purposes are shielded while in storage to keep personnel exposure ALARA. Sources used to service or calibrate plant instrumentation are also routinely brought on-site by contractors. Radiography is performed by the licensed utility group or licensed contractors. These sources are maintained and used in accordance with the provisions of the utility group's or contractor’s license. Additional requirements and restrictions may apply depending on the type of source, use, and intended location of use. If the utility group or contractor source must be stored on-site, designated plant personnel must approve the storage location, and identify appropriate measures for maintaining security and personnel protection.

During the period prior to the implementation of the Emergency Plan (in preparation for the initial fuel loading following the 52.103(g) finding), no specific materials related emergency plan will be necessary because:

a) No byproduct material will be received, possessed, or used in a physical form that is “in unsealed form, on foils or plated sources, or sealed in glass,” that exceeds the quantities in Schedule C in 10 CFR 30.72, and

b) No 10 CFR Part 40 specifically licensed source material, including natural uranium, depleted uranium and uranium hexafluoride will be received, possessed, or used during this period.

The following radioactive sources will be used for the Radiation Monitoring System and laboratory/portable monitoring instrumentation:[1]

Radioactive Licensee Material (Element and Mass Number)[1]	Chemical and/or Physical Form[1]	Maximum Quantity That Licensee May Possess at Any One Time[1]
• Any byproduct material with atomic numbers 1 through 93 inclusive	Sealed Sources[2]	No single source to exceed 100 millicuries 5 Curies total
• Americium-241	Sealed Sources[2]	No single source to exceed 300 millicuries 500 millicuries total

Notes: 1. This information remains in effect between the issuance of the COL and the Commission's 52.103(g) finding for each unit, and will be designated historical information after that time.

2. Includes calibration and reference sources.

12.2.1.3 Sources for the Core Melt Accident

Revise the last paragraph of DCD Subsection 12.2.1.3 to read as follows:

12.2.1.3.1 Containment

PTN DEP 6.4-1

If there is core degradation, core cooling would be provided by the passive core cooling system which is totally inside the containment such that no high activity sump solution would be recirculated outside the containment. The shielding provided for the containment addresses this post-LOCA source term. The source strengths as a function of time are provided in DCD Table 12.2-20 and the integrated source strengths are provided in DCD Table 12.2-21.

12.2.1.3.2 Main Control Room HVAC Filters

PTN DEP 6.4-1

During operation of the nuclear island nonradioactive ventilation system (VBS) supplemental filtration or the main control room emergency habitability system (VES), filters in the control room HVAC work to remove particulate and iodine from the air. As radioactivity accumulates within the filters, this becomes a potential

source of dose. These source strengths as a function of time are provided in Table 12.2-201 and the integrated source strengths are provided in Table 12.2-202.

12.2.3 COMBINED LICENSE INFORMATION

STD COL 12.2-1 This COL item is addressed in Subsection 12.2.1.1.10.

PTN DEP 6.4-1

Table 12.2-201 (Sheet 1 of 2)
Core Melt Accident Source Strengths from MCR HVAC Filters as a Function of Time

VES Filter[1] Source Strengths after a Loss of Coolant Accident				
Energy Group (Mev/gamma)	Source Strength (Mev/sec)			
	2 hours	8 hours	24 hours	30 days
0.01-0.02	1.19E+06	3.11E+06	1.81E+06	1.97E+05
0.02-0.03	1.47E+06	5.26E+06	3.89E+06	2.65E+05
0.03-0.06	2.87E+06	8.30E+06	5.46E+06	6.74E+05
0.06-0.1	3.03E+06	8.13E+06	5.22E+06	5.41E+05
0.1-0.2	5.76E+06	1.41E+07	8.76E+06	9.02E+05
0.2-0.4	6.14E+07	2.61E+08	2.46E+08	1.87E+07
0.4-0.6	1.86E+08	6.02E+08	3.60E+08	1.83E+07
0.6-0.7	1.47E+08	2.33E+08	1.47E+08	1.03E+08
0.7-0.8	1.09E+08	1.80E+08	1.05E+08	7.30E+07
0.8-1.0	1.85E+08	1.67E+08	6.99E+07	7.13E+06
1.0-1.5	3.36E+08	6.99E+08	1.85E+08	1.22E+07
1.5-2.0	1.21E+08	2.55E+08	4.97E+07	2.69E+04
2.0-3.0	3.13E+07	3.87E+07	7.28E+06	9.07E+03
3.0-4.0	3.68E+05	5.98E+03	5.56E+02	1.41E+02
4.0-5.0	1.42E+04	3.16E+01	8.55E-04	7.80E-04
5.0-6.0	3.31E-05	3.12E-04	3.35E-04	3.21E-04
6.0-7.0	1.32E-05	1.24E-04	1.33E-04	1.28E-04
7.0-8.0	5.11E-06	4.82E-05	5.17E-05	4.96E-05
8.0-10.0	2.68E-06	2.53E-05	2.71E-05	2.60E-05
10.0-14.0	1.69E-07	1.60E-06	1.71E-06	1.64E-06
Total	1.19E+09	2.47E+09	1.19E+09	2.35E+08

Notes: 1) Based upon a particulate filter density of 0.212 g/cc and charcoal filter density of 0.440 g/cc.

PTN DEP 6.4-1

Table 12.2-201 (Sheet 2 of 2)
Core Melt Accident Source Strengths from MCR HVAC Filters as a Function of Time

VBS Filter[2] Source Strengths after a Loss of Coolant Accident				
Energy Group (Mev/gamma)	Source Strength (Mev/sec)			
	2 hours	8 hours	24 hours	30 days
0.01-0.02	6.86E+08	1.00E+09	5.75E+08	6.21E+07
0.02-0.03	9.55E+08	1.76E+09	1.27E+09	8.46E+07
0.03-0.06	1.71E+09	2.71E+09	1.75E+09	2.10E+08
0.06-0.1	1.72E+09	2.60E+09	1.63E+09	1.70E+08
0.1-0.2	3.49E+09	4.61E+09	2.81E+09	2.91E+08
0.2-0.4	3.54E+10	8.45E+10	7.59E+10	5.76E+09
0.4-0.6	1.03E+11	1.91E+11	1.10E+11	5.61E+09
0.6-0.7	7.99E+10	7.20E+10	4.39E+10	3.04E+10
0.7-0.8	5.97E+10	5.62E+10	3.17E+10	2.16E+10
0.8-1.0	1.03E+11	5.23E+10	2.13E+10	2.11E+09
1.0-1.5	1.86E+11	2.20E+11	5.64E+10	3.62E+09
1.5-2.0	6.71E+10	8.03E+10	1.53E+10	8.78E+06
2.0-3.0	1.66E+10	1.22E+10	2.24E+09	3.09E+06
3.0-4.0	1.82E+08	1.93E+06	1.89E+05	4.81E+04
4.0-5.0	6.86E+06	7.65E+03	2.91E-01	2.65E-01
5.0-6.0	3.74E-02	1.12E-01	1.14E-01	1.09E-01
6.0-7.0	1.49E-02	4.47E-02	4.54E-02	4.35E-02
7.0-8.0	5.78E-03	1.74E-02	1.76E-02	1.69E-02
8.0-10.0	3.03E-03	9.11E-03	9.24E-03	8.86E-03
10.0-14.0	1.92E-04	5.75E-04	5.84E-04	5.60E-04
Total	6.59E+11	7.82E+11	3.65E+11	7.00E+10

Notes: 2) Based upon a particulate filter density of 0.230 g/cc and charcoal filter density of 0.632 g/cc.

PTN DEP 6.4-1

Table 12.2-202
Core Melt Accident Integrated Source Strengths from MCR HVAC Filters

Energy Group (Mev/gamma)	30-Day Integrated Source Strength (Mev)	
	VES(1)	VBS(2)
0.01-0.02	1.75E+08	5.65E+10
0.02-0.03	3.81E+08	1.26E+11
0.03-0.06	5.89E+08	1.90E+11
0.06-0.1	5.77E+08	1.84E+11
0.1-0.2	9.03E+08	2.95E+11
0.2-0.4	3.34E+10	1.05E+13
0.4-0.6	2.36E+10	7.44E+12
0.6-0.7	3.81E+10	1.15E+13
0.7-0.8	2.63E+10	7.92E+12
0.8-1.0	7.57E+09	2.39E+12
1.0-1.5	1.77E+10	5.67E+12
1.5-2.0	4.03E+09	1.34E+12
2.0-3.0	6.47E+08	2.18E+11
3.0-4.0	1.20E+06	4.46E+08
4.0-5.0	4.17E+04	1.52E+07
5.0-6.0	1.03E-01	3.51E+01
6.0-7.0	4.08E-02	1.40E+01
7.0-8.0	1.59E-02	5.42E+00
8.0-10.0	8.32E-03	2.84E+00
10.0-14.0	5.25E-04	1.80E-01
Total	1.54E+11	4.79E+13

Notes:
1) Based upon a particulate filter density of 0.212 g/cc and charcoal filter density of 0.440 g/cc.
2) Based upon a particulate filter density of 0.230 g/cc and charcoal filter density of 0.632 g/cc.

12.3 RADIATION PROTECTION DESIGN FEATURES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

12.3.1.2 Radiation Zoning and Access Control

PTN DEP 18.8-1 DCD Figure 12.3-1 (Sheet 11 of 16), DCD Figure 12.3-2 (Sheet 11 of 15), and DCD Figure 12.3-3 (Sheet 11 of 16) are modified to reflect the relocation of the Operations Support Center by changing the description of room number 40318 from "ALARA BRIEFING RM AND OPERATIONAL SUPPORT CENTER" to "ALARA BRIEFING RM."

12.3.2.2.7 Control Room Shielding Design

Revise DCD Subsection 12.3.2.2.7 to read as follows:

PTN DEP 6.4-1 The design basis loss-of-coolant accident dictates the shielding requirements for the control room. The rod ejection accident dictates the shielding requirements for the main control room emergency habitability (VES) filter in the operator break room. Consideration is given to shielding provided by the shield building structure. Shielding combined with other engineered safety features is provided to permit access and occupancy of the control room following a postulated loss-of-coolant accident, so that radiation doses are limited to five rem whole body from contributing modes of exposure for the duration of the accident, in accordance with General Design Criterion 19.

Shielding of the VES filtration unit is accomplished by safety-related metal shielding. This shielding is composed of either tungsten that is 0.25 inches thick or stainless steel shown to provide an equivalent amount of shielding. The length and width of the shielding are designed to match the length and width of the filtration unit being shielded.

12.3.4 AREA RADIATION AND AIRBORNE RADIOACTIVITY MONITORING INSTRUMENTATION

Add the following text to the end of DCD Subsection 12.3.4.

STD COL 12.3-2 Procedures detail the criteria and methods for obtaining representative measurement of radiological conditions, including in-plant airborne radioactivity concentrations in accordance with applicable portions of 10 CFR Part 20 and consistent with the guidance in Regulatory Guides 1.21-Appendix A, 8.2, 8.8, and 8.10. Additional discussion of radiological surveillance practices is included in the radiation protection program description provided in Appendix 12AA.

Surveillance requirements are determined by the functional manager in charge of radiation protection based on actual or potential radiological conditions encountered by personnel and the need to identify and control radiation, contamination, and airborne radioactivity. These requirements are consistent with the operational philosophy in Regulatory Guide 8.10. Frequency of scheduled surveillance may be altered by permission of the functional manager in charge of radiation protection or their designee. Radiation Protection periodically provides cognizant personnel with survey data that identifies radiation exposure gradients in area resulting from identified components. This data includes recent reports, with survey data, location and component information.

The following are typical criteria for frequencies and types of surveys:

Job Coverage Surveys

- Radiation, contamination, and/or airborne surveys are performed and documented to support job coverage.
- Radiation surveys are sufficient in detail for Radiation Protection to assess the radiological hazards associated with the work area and the intended/specified work scope.
- Surveys are performed commensurate with radiological hazard, nature and location of work being conducted.
- Job coverage activities may require surveys to be conducted on a daily basis where conditions are likely to change.

Radiation Surveys

- Radiation surveys are performed at least monthly in any radiological controlled area (RCA) where personnel may frequently work or enter. Survey frequencies may be modified by the functional manager in charge of radiation protection as previously noted.

- Radiation surveys are performed prior to or during entry into known or suspected high radiation areas for which up to date survey data does not exist.

- Radiation surveys are performed prior to work involving highly contaminated or activated materials or equipment.

- Radiation surveys are performed at least semiannually in areas outside the RCA. Areas to be considered include shops, offices, and storage areas.

- Radiation surveys are performed to support movement of highly radioactive material.

- Neutron radiation surveys are performed when personnel may be exposed to neutron emitting sources.

Contamination Surveys

- Contamination surveys are performed at least monthly in any RCA where personnel may frequently work or enter. Survey frequencies may be modified by the functional manager in charge of radiation protection as previously noted.

- Contamination surveys are performed during initial entry into known or suspected contamination area(s) for which up to date survey data does not exist.

- Contamination surveys are performed at least daily at access points, change areas, and high traffic walkways in RCAs that contain contaminated areas. Area access points to a High Radiation Area or Very High Radiation Area are surveyed prior to or upon access by plant personnel or if access has occurred.

- Contamination surveys are performed at least semiannually in areas outside the RCA. Areas to be considered include shops, offices, and storage areas.

- A routine surveillance is conducted in areas designated by the functional manager in charge of radiation protection or their designee likely to indicate alpha radioactivity. If alpha contamination is identified, frequency and scope of the routine surveillance is increased.

Airborne Radioactivity Surveys

- Airborne radioactivity surveys are performed during any work or operation in the RCA known or suspected to cause airborne radioactivity (e.g., grinding, welding, burning, cutting, hydrolazing, vacuuming, sweeping, use of compressed air, using volatiles on contaminated material, waste processing, or insulation).

- Airborne radioactivity surveys are performed during a breach of a radioactive system, which contains or is suspected of containing significant levels of contamination.

- Airborne radioactivity surveys are performed during initial entry (and periodically thereafter) into any known or suspected airborne radioactivity area.

- Airborne radioactivity surveys are performed immediately following the discovery of a significant radioactive spill or spread of radioactive contamination, as determined by the functional manager in charge of radiation protection.

- Airborne radioactivity surveys are performed daily in occupied radiological controlled areas where the potential for airborne radioactivity exists, including containment.

- Airborne radioactivity surveys are performed any time respiratory protection devices, alternative tracking methods such as derived air concentration-hour (DAC-hr), and/or engineering controls are used to control internal exposure.

- Airborne radioactivity surveys are performed using continuous air monitors (CAMs) for situations in which airborne radioactivity levels can fluctuate and early detection of airborne radioactivity could prevent or minimize inhalations of radioactivity by workers. Determination of air flow patterns are considered for locating air samplers.

- Airborne radioactivity surveys are performed prior to use and monthly during use on plant service air systems used to supply air for respiratory protection to verify the air is free of radioactivity.

- Tritium sampling is performed near the spent fuel pit when irradiated fuel is in the pit and other areas of the plant where primary system leaks occur and tritium is suspected.

Appropriate counting equipment is used based on the sample type and the suspected identity of the radionuclides for which the sample is being done. Survey results are documented, retrievable, and processed per site document control and records requirements consistent with Regulatory Guide 8.2. Completion of survey documentation includes the update of room/area posting maps and revising area or room postings and barricades as needed.

Air samples indicating activity levels greater than a procedure specified percentage of DAC are forwarded to the radiochemistry laboratory for isotopic analysis. Samples which cannot be analyzed on-site are forwarded to an off-site laboratory or a contractor for analysis; or, the DAC percentage may be hand calculated using appropriate values from 10 CFR Part 20, Appendix B.

The responsible radiation protection personnel review survey documentation to evaluate if surveys are appropriate and obtained when required, records are complete and accurate, and adverse trends are identified and addressed.

An in-plant radiation monitoring program maintains the capability to accurately determine the airborne iodine concentration in areas within the facility where personnel may be present under accident conditions. This program includes the training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment consistent with Regulatory Guides 1.21 (Appendix A) and 8.8. Training and personnel qualifications are discussed in Appendix 12AA.

A portable monitor system meeting the requirements of NUREG-0737, Item III.D.3.3, is available. The system uses a silver zeolite or charcoal iodine sample cartridge and a single-channel analyzer. The use of this portable monitor is incorporated in the emergency plan implementing procedures. The portable monitor is part of the in-plant radiation monitoring program. It is used to determine the airborne iodine concentration in areas where plant personnel may be present during an accident. Accident monitoring instrumentation complies with applicable parts of 10 CFR Part 50, Appendix A.

Sampling cartridges can be removed to a low background area for further analysis. These cartridge samples can be purged of any entrapped noble gases, when necessary, prior to being analyzed.

12.3.5.1 Administrative Controls for Radiological Protection

STD COL 12.3-1 This COL Item is addressed in Subsection 12.5.4 and Appendix 12AA.

12.3.5.2 Criteria and Methods for Radiological Protection

STD COL 12.3-2 This COL Item is addressed in Subsection 12.3.4.

12.3.5.3 Groundwater Monitoring Program

STD COL 12.3-3 This COL Item is addressed in Appendix 12AA.

12.3.5.4 Record of Operational Events of Interest for Decommissioning

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STD COL 12.3-4 This COL Item is addressed in Appendix 12AA.

PTN DEP 6.4-1

Figure 12.3-1R Radiation Zones, Normal Operations/Shutdown, Nuclear Island, Elevation 100'-0" & 107'-2"

Security-Related Information — Withheld Under 10 CFR 2.390(d)
(See Part 9 of this COL Application)

12.4 DOSE ASSESSMENT

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

Add the following new subsection after DCD Subsection 12.4.1.8:

PTN SUP 12.4-1

12.4.1.9 Dose to Construction Workers

This section evaluates the potential radiological dose impacts to construction workers at the Turkey Point Units 6 & 7, resulting from the operation of Units 3, 4, and 6. Construction workers at Units 6 & 7 may be exposed to direct radiation and gaseous effluents from Units 3 & 4. Because a portion of the Unit 7 construction period overlaps operation of Unit 6, construction workers at Unit 7 may also be exposed to direct radiation and gaseous radioactive effluents from Unit 6. Doses are calculated below for Unit 7 construction workers, but these may be conservatively applied to Unit 6 workers also.

12.4.1.9.1 Site Layout

Figure 2.1-203 indicates the locations of Units 3 & 4, and Units 6 & 7. Construction activity for Unit 7 is outside the protected area for Unit 6 but inside the restricted area boundary.

12.4.1.9.2 Radiation Sources

Unit 6 will be constructed before Unit 7. Workers constructing Units 6 & 7 may be exposed to direct radiation and gaseous radioactive effluents emanating from the routine operation of Units 3 & 4. Construction workers at Unit 7 are not exposed to any radiation source from Unit 6 until it becomes operational. In addition to the dose from Units 3 & 4, construction workers on Unit 7 may receive doses from direct radiation from Unit 6, from airborne effluents from Unit 6, and from background radiation.

For Unit 6, the radiation exposure at the site boundary is considered in DCD Section 12.4.2. As stated in that section, direct radiation from the containment and other plant buildings is negligible. Additionally, there is no contribution from refueling water since the refueling water is stored inside the containment instead of in an outside storage tank.

Direct radiation from the Units 3 & 4 containments and other plant buildings is negligible. Routine operational thermo-luminescent dosimeter (TLD) measurements at the Units 3 & 4 site show that dose rates are comparable to those observed during the preoperational surveillance program. Another source of direct radiation is an independent spent fuel storage installation (ISFSI) that is planned to be located east of Units 3 & 4 at a distance of approximately 3000 feet from the Units 6 & 7 construction area. Small quantities of monitored airborne effluents are normally released from Units 3 & 4 from the waste gas decay tanks, reactor building purges, and incidental plant releases. Construction workers are assumed to be exposed to the gaseous effluent doses from the routine operation of Units 3 & 4.

For Unit 6, small quantities of monitored airborne effluents are normally released through the plant vent or the turbine building vent. The plant vent provides the release path for containment venting releases, auxiliary building ventilation releases, annex building releases, radwaste building releases, and gaseous radwaste system discharge. The turbine building vents provide the release path for the condenser air removal system, gland seal condenser exhaust, and the turbine building ventilation releases. The ventilation system is described in DCD Section 9.4. The expected radiation sources (nuclides and activities) in the gaseous effluents are listed in DCD Table 11.3-3.

Potable water for construction workers is provided from an external source that is not affected by the liquid discharge from Unit 6 or any of the existing units. Therefore, construction workers receive no internal dose from the liquid effluent pathway.

While Unit 6 is operating and Unit 7 is under construction, workers may be externally exposed to liquid effluents from Unit 6 while performing Unit 7 liquid waste effluent discharge piping connections. However, this work will be performed by trained and monitored radiation workers, not general site construction workers. Hence, this activity is not considered a contributor to general site construction worker doses.

12.4.1.9.3 Construction Worker Dose Estimates

Although there has been no measurable direct radiation from Units 3 & 4, the direct dose rate in the Units 6 & 7 construction area from each existing unit is assumed to be 1 mrem per year. Compared to this, the calculated dose rate of 0.013 mrem per year from a fully loaded ISFSI is negligible.

The determination of construction worker doses from Unit 6 operation depends on the airborne effluent released and the atmospheric transport to the worker location. The methodology contained in the GASPAR II program was used to determine the doses for gaseous pathways. This program implements the radiological exposure models described in RG 1.109 for radioactivity releases in gaseous effluent. The XOQDOQ computer code (NUREG/CR-2919) was used to determine the X/Q and D/Q values in the Unit 7 construction area from Unit 6 releases. Gaseous effluent doses from Units 3 & 4 were estimated from the annual effluent reports for those units.

Dose rate estimates were calculated for construction workers exposed to gaseous radioactive effluents through the following pathways:

- Direct radiation from immersion in the gaseous effluent plume and from particulates deposited on the ground.
- Inhalation of gases and particulates.

For the purposes of these calculations, the X/Q value (1.6E-04 seconds per cubic meter [sec/m^3] calculated at 0.13 mile west), obtained from Table 2.3.5-202, was used in GASPAR II to calculate construction worker doses from the gaseous pathway, and conservatively bounds the construction worker location at Unit 7.

GASPAR II doses calculated at 0.13 mile were adjusted based on construction worker residence time on the site or 2080 hours/8760 hours = 0.24. Results are presented in Table 12.4-201.

12.4.1.9.4 Compliance with Dose Regulations

Turkey Point Units 6 & 7 construction workers are, for the purposes of radiation protection, members of the general public. This means that the dose rate limit is 100 mrem/year. The construction workers (with the exception of certain specialty contractors loading fuel or using industrial radiation sources for radiography) do not deal with radiation sources.

There are three regulations that govern dose rates to members of the general public. Dose rate limits to the public are provided in 10 CFR 20.1301, 10 CFR 20.1302, and 10 CFR Part 50, Appendix I. The design objectives of 10 CFR 50, Appendix I, apply relative to maintaining dose as ALARA for construction workers. In addition, 40 CFR Part 190 applies as it is referred to in 10 CFR 20.1301. The requirements of 10 CFR 20.1201 through 20.1204 do not apply to the construction

workers because they are considered members of the public and not radiation workers.

12.4.1.9.5 Collective Doses to Unit 7 Workers

Collective construction worker doses were conservatively estimated using the following information:

- The estimated maximum dose rate for the gaseous pathway.
- A construction worker exposure time of 2080 hours per year (40 hours per week for 52 weeks).
- An estimated peak loading of 2800 construction workers per year for Unit 7 construction while Unit 6 is operating.

The collective dose is the sum of all doses received by all workers. It is a measure of population risk. The total annual worker collective dose is 17 person-rem.

Table 12.4-202 compares the estimated doses to a Units 6 & 7 construction worker with the public dose criteria of 10 CFR 20.1301. This comparison demonstrates compliance with 10 CFR 20.1301 criteria and supports the conclusion that those who will construct Units 6 & 7 would not need to be classified as radiation workers nor would they require monitoring.

STD SUP 12.4-1

12.4.1.9.6 Operating Unit Radiological Surveys

The operating unit conducts radiological surveys in the unrestricted and controlled area and radiological surveys for radioactive materials in effluents discharged to unrestricted and controlled areas in implementing 10 CFR 20.1302. These surveys demonstrate compliance with the dose limits of 10 CFR 20.1301 for construction workers.

PTN SUP 12.4-1

Table 12.4-201
Construction Worker Dose Summary During Unit 7 Construction

Source	Pathway	Annual Dose (mrem TEDE)
Units 3 & 4	Direct Radiation[a]	0.47
	Gaseous Effluent[b]	0.0023
Unit 6	Gaseous Effluent[c]	5.5
Total		6.0

(a) Direct radiation dose for Units 3 & 4 is determined as follows:
(1 mrem/yr-unit)(2 units)(2080 hr/yr)(8760 hr/yr) = 0.47 mrem.

(b) Gaseous effluent doses for Units 3 & 4 are the maximum values from the annual effluent reports for 2004 to 2008, adjusted for annual occupancy of 2080 hr/yr.

(c) Gaseous effluent doses for Unit 6 are calculated using GASPAR II as 5.2 mrem for total body and 7.9 mrem for thyroid, adjusted for annual occupancy of 2080 hr/yr. The TEDE value of 5.5 rem is estimated by multiplying the thyroid dose by a weighting factor of 0.03 and adding the product to the total body dose.

PTN SUP 12.4-1

Table 12.4-202
Comparison of Units 6 & 7 Construction Worker Estimated Radiation Doses to 10 CFR 20.1301 Public Dose Criteria

Type of Radiation Dose	Public Dose Limits 10 CFR 20.1301	Estimated Construction Worker Dose
Total effective dose equivalent	100 mrem/yr	6.0 mrem/yr
Maximum dose in any 1 hour	2 mrem	2.9E-03 mrem

12.5 HEALTH PHYSICS FACILITIES DESIGN

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

12.5.2.2 Facilities

Revise the first sentence of DCD Subsection 12.5.2.2 to read:

PTN DEP 18.8-1 The ALARA briefing room is located off the main corridor immediately beyond the main entry to the annex building.

12.5.3.2 Job Planning Facilities

Revise the first sentence of DCD Subsection 12.5.3.2 to read:

PTN DEP 18.8-1 The ALARA briefing room in the annex building is an example of such a facility where job planning and ALARA briefing and debriefing activities can take place.

12.5.4 CONTROLLING ACCESS AND STAY TIME

Add the following text to the end of DCD Subsection 12.5.4.

STD COL 12.3-1 A closed circuit television system may be installed in high radiation areas to allow remote monitoring of individuals entering high radiation areas by personnel qualified in radiation protection procedures.

12.5.5 COMBINED LICENSE INFORMATION

STD COL 12.5-1 This COL Item is addressed in Appendix 12AA.

Add the following Appendix after Section 12.5 of the DCD.

APPENDIX 12AA RADIATION PROTECTION PROGRAM DESCRIPTION

STD COL 12.1-1
STD COL 12.3-1
STD COL 12.5-1

This appendix incorporates by reference NEI 07-03A, Generic FSAR Template Guidance for Radiation Protection Program Description. See Table 1.6-201. The numbering of NEI 07-03A is revised from 12.5# to 12AA.5# through the document, with the following revisions and additions as indicated by strikethroughs and underlines.Table 13.4-201 provides milestones for radiation protection program implementation.

Revise bullet number 3 of NEI 07-03A Subsection 12.5 as follows:

3. Prior to initial loading of fuel in the reactor, all of the radiation program functional areas described in Appendix 12AA ~~Section 12.5~~ will be fully implemented, with the exception of the organization, facilities, equipment, instrumentation, and procedures necessary for transferring, transporting or disposing of radioactive materials in accordance with 10 CFR Part 20, Subpart K, and applicable requirements in 10 CFR Part 71. In addition, the position of radiation protection manager (as described in ~~s~~Section 13.1~~12.5.2.3~~) will be filled and at least one (1) radiation protection technician for each operating shift, selected, trained, and qualified consistent with the guidance in Regulatory Guide 1.8, will be onsite and on duty when fuel is initially loaded in the reactor, and thereafter, whenever fuel is in the reactor.

Revise the first paragraph of NEI 07-03A Subsection 12.5.2 as follows:

Qualification and training criteria for site personnel are consistent with the guidance in Regulatory Guide 1.8 and are described in FSAR Chapter 13. Specific radiation protection responsibilities for key positions within the plant organization are described in Section 13.1~~below~~.

Subsections 12.5.2.1 through 12.5.2.5 of NEI 07-03A are not incorporated into Appendix 12AA.

Subsection 12.5.3.1 of NEI 07-03A is not incorporated into Appendix 12AA. Facilities are described in DCD Subsection 12.5.2.2.

Add the following text after the first paragraph of NEI 07-03A Subsection 12.5.3.3.

If circumstances arise in which NIOSH tested and certified respiratory equipment is not used, compliance with 10 CFR 20.1703(b) and 20.1705 is maintained.

The following headings (and associated material) in Subsection 12.5.4.2 of NEI 07-03A are described in DCD Subsection 12.5.3, and are therefore not incorporated into Appendix 12AA:

- Radwaste Handling
- Spent Fuel Handling
- Normal Operation
- Sampling

Add the following text after the second paragraph of NEI 07-03A Subsection 12.5.4.4.

STD COL 12.3-1 Table 12AA-201 identifies plant areas designated as Very High Radiation Areas (VHRAs), lists corresponding plant layout drawings showing the VHRA DCD Section 12.3, specifies the condition under which the area is designated VHRA, identifies the primary source of the VHRA, and summarizes the frequency of access and reason for access. VHRAs are listed as Radiation Zone IX, which corresponds to a dose rate greater than 500 rad/hr.

In each of the VHRAs, with the exception of the Reactor Vessel Cavity and Delay-Bed/Guard-Bed Compartment, the primary radioactive source is transient (such as fuel passing through the transfer tube), removable (such as resin in the demineralizers), or can be relocated. When the primary source is removed, the dose rate in each of these areas will be less than Zone IX and, in effect, the area will no longer be a VHRA. With planning, the need for human entrance to a VHRA when the primary source is present can be largely or entirely avoided.

In addition to the access control requirements for high radiation areas, the following control measures are implemented to control access to very high radiation areas in which radiation levels could be encountered at 500 rads or more in one hour at one meter from a radiation source or any surface through which the radiation penetrates:

— Sign(s) conspicuously posted stating GRAVE DANGER, VERY HIGH RADIATION AREA.

— Area is locked. Each lock shall have a unique core. The keys shall be administratively controlled by the functional manager in charge of radiation protection as described in Section 13.1.

— Plant Manager's (or designee) approval required for entry.

— Radiation Protection personnel shall accompany person(s) making the entry. Radiation Protection personnel shall assess the radiation exposure conditions at the time of the entry.

A verification walk down will be performed with the purpose of verifying barriers to the Very High Radiation Areas in the final design of the facility are consistent with Regulatory Guide 8.38 guidance as part of the implementation of the Radiation Protection and ALARA programs on the schedule identified in Table 13.4-201.

Revise the third paragraph of NEI 07-03A Subsection 12.5.4.7 as follows.

STD COL 12.1-1
STD COL 12.3-1
STD COL 12.5-1

As described in Sections 12.1, ~~12.5.1~~Appendix 12AA, and ~~12.5.2~~13.1, management policy is established, and organizational responsibilities and authorities are assigned to implement an effective program for maintaining occupational radiation exposures ALARA. Procedures are established and implemented that are in accordance with 10 CFR 20.1101 and consistent with the guidance in Regulatory Guides 8.8 and 8.10. Examples of such procedures include the following:

Add the following text after the last bullet of NEI 07-03A Subsection 12.5.4.8.

STD COL 12.5-1

This subsection adopts NEI 08-08A (Reference 201), for a description of the operational and programmatic elements and controls that minimize contamination of the facility, site, and the environment, to meet the requirements of 10 CFR 20.1406.

Revise the first paragraph of Subsection 12.5.4.12 of NEI 07-03A to read:

STD COL 12.5-1 The radiation protection program and procedures are established, implemented, maintained, and reviewed consistent with the 10 CFR 20.1101 and the quality assurance criteria described in Part III of the Quality Assurance Program Description described in Section 17.5.

Add the following Subsection to the information incorporated from NEI 07-03A.

STD COL 12.3-3 12AA.5.4.14 Groundwater Monitoring Program

A groundwater monitoring program beyond the normal radioactive effluent monitoring program is developed. If necessary to support this groundwater monitoring program, design features will be installed during the plant construction process. Areas of the site to be specifically considered in this groundwater monitoring program are (all directions based on plant standard):

- West of the auxiliary building in the area of the fuel transfer canal.
- West and south of the radwaste building.
- East of the auxiliary building rail bay and the radwaste building truck doors.

This subsection adopts NEI 08-08A (Reference 201), for the Groundwater Monitoring Program description.

Add the following Subsection to the information incorporated from NEI 07-03A.

STD COL 12.3-4 12AA.5.4.15 Record of Operational Events of Interest for Decommissioning

This subsection adopts NEI 08-08A (Reference 201), for discussion of recordkeeping practices important to decommissioning.

Revise the REFERENCES section of NEI 07-03A, Reference 8, as follows:

8. Regulatory Guide 1.97, Revision 3, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."~~4,"Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants."~~

Add the following reference to the NEI 07-03A REFERENCES.

201. Nuclear Energy Institute, *Generic FSAR Template Guidance for Life Cycle Minimization of Contamination*, NEI 08-08A, Rev. 0, October 2009.

STD COL 12.3-1

Table 12AA-201 (Sheet 1 of 2)
Very High Radiation Areas (VHRA)

Room Number	VHRA Location	DCD Figure 12.3-1, Sheet No.	Primary Source(s)	VHRA Conditional Notes	Frequency of Access to VHRA Areas While VHTRA Conditions Exist
11105	Reactor Vessel Cavity	3, 4, 5	Neutron activation of the material in and around the cavity during reactor operations, such as the concrete shield walls and the reactor insulation	Note 1	None Required
12151	Spent Fuel Pool Cooling System/Liquid Radwaste System Demineralizer/ Filter room (Inside Wall)	3	Resin in vessels	Notes 6, 8	None Required
12153	Delay-Bed/Guard-Bed Compartment	3	Activated carbon holding radioactive gases	Note 10	None required
12371	Filter-Storage Area	6, 7	Spent filter cartridges	Notes 4, 6, 7	None required
12372	Resin Transfer Pump/ Valve Room	6	Spent resin in lines	Note 6	None Required
12373	Spent-Resin Tank Room	6	Spent resin in tanks	Note 6	None Required
12374	Waste Disposal Container Area	6	Spent resin in vault	Note 6	None Required
12463	Cask Loading Pit	6	Spent fuel	Notes 2, 6	None Required
12563	Spent Fuel Pit	5, 6	Spent fuel	Note 6	None Required
Fuel Transfer Areas					
12564	Fuel Transfer Tube	6	Fuel in transit	Notes 2, 5, 9	None Required
11205	Reactor Vessel Nozzle Area	5	Fuel in transit	Notes 2, 3, 9	None Required
11504	Refueling Cavity	6	Fuel in transit	Notes 2, 3, 9	None Required

STD COL 12.3-1

Table 12AA-201 (Sheet 2 of 2)
Very High Radiation Areas (VHRA)

Notes

1. VHRA during full power operation; less than 10 Rem/hr 24 hours after plant shutdown.
2. During underwater spent fuel transfer operations, this area can be as high as VHRA.
3. During underwater reactor internals transfers/storage, this area can be as high as VHRA.
4. During spent resin waste disposal container transfer or loading, this area can be as high as VHRA. The contact dose rate of spent resin containers can be greater than 1000 Rem/hr.
5. Discussion about the Spent Fuel Transfer Canal and Tube Shielding is provided in DCD Subsection 12.3.2.2.9.
6. Source is transient, removable, or can be relocated.
7. VHRA when hatch is removed during spent resin container handling operation.
8. In the event that the room does need to be accessed for maintenance or other reasons, temporary shielding is put in place and the resin is removed from the vessels. These measures reduce exposure rates in the room, such that this room is no longer a VHRA. Remote handling is used for any tasks that require the opening of the access hatch in the ceiling of this room when media is present.
9. These areas have no planned reasons for entry and are only classified as VHRAs during periods of fuel movement. In the event that these rooms do need to be accessed to repair the Fuel-Transfer System, Fuel Transfer Tube Gate Valve, or other components, it is done during a non-fuel movement time. This keeps the dose received by the worker as low as reasonably achievable.
10. Inspection of the equipment in this room, when required, is done using remote viewing equipment. Two plugs between Room 12153 and 12155 contain instruments and the plugs are expected to be removed every 12 to 18 months for performance of maintenance. Administrative procedures are implemented to protect workers pursuant to Regulatory Guide 8.38.

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CHAPTER 13 CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE OF APPLICANT

This section of the referenced DCD is incorporated by reference, with the following departures and/or supplements.

STD DEP 1.1-1

DCD Subsection 13.1.1, Combined License Information, is renumbered in this FSAR section to Section 13.1.4.

PTN COL 13.1-1

This section describes organizational positions of a nuclear power unit and owner/applicant corporations and associated functions and responsibilities.

Table 13.1-201, Generic Position/Site Specific Position Cross Reference, provides a cross-reference to identify the corresponding generic position titles.

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

FPL has more than 35 years of experience in the design, construction, and operation of nuclear generating units in Florida. FPL is a subsidiary of NextEra Energy and is part of NextEra Energy's Nuclear Fleet Organization. In addition to FPL, NextEra Energy's Nuclear Fleet Organization includes three holding companies and a Juno Beach, Florida-based fleet support office. The NextEra Energy Nuclear Fleet Organization operates 10 nuclear units at five sites: Duane Arnold, Seabrook, Turkey Point Units 3 & 4 and 6 & 7, Saint Lucie Units 1 & 2, and Point Beach Units 1 & 2. The Nuclear Fleet Organization includes, but is not limited to, nuclear extended power uprate, nuclear operations, fleet support, engineering support, fleet organizational support, and nuclear assurance.

13.1.1.1 Design, Construction, and Operating Responsibilities

The NextEra Energy president and chief executive officer (CEO) promulgates corporate policy and provides corporate direction to the executive vice president and chief nuclear officer, and to other members of the senior management staff. Line responsibilities for implementing policies and direction are assigned to the executive vice president–engineering, construction and corporate services, and to the executive vice president and chief nuclear officer. The executive vice president–engineering, construction and corporate services directs the vice president–new nuclear projects in the design and construction of new nuclear

plant generation. The executive vice president and chief nuclear officer directs the site vice presidents, the vice president-nuclear fleet technical support, the vice president–nuclear power uprate, the director of quality and process improvement, and director-nuclear assurance in support of the operation of the current plants. The first priority and responsibility of each member of the nuclear staff throughout the life of the plant is nuclear safety. Decisions regarding unit activities are made conservatively, with expectations of this core value of nuclear safety regularly communicated to appropriate personnel by management interface, training, and unit directives.

Lines of authority, decision making, and communication are clearly and unambiguously established to enable various project members, including contractors, to understand that utility management is in charge and directs the project. Key executive and corporate management positions, functions, and responsibilities are described in Subsection 13.1.1.3.1. The corporate organization is shown in Figure 13.1-203. The management and technical support organization for design, construction, and preoperational activities is addressed in Appendix 13AA.

13.1.1.2 Provisions for Technical Support Functions

Before beginning preoperational testing, the vice president–new nuclear projects, the Turkey Point site vice president, the plant general manager for Units 6 & 7, and the chief nuclear officer (CNO) establish the organization of directors, managers, functional managers, supervisors, and staff sufficient to perform required functions for support of safe plant operation. These functions include the following:

- Nuclear, mechanical, structural, electrical, thermal-hydraulic, metallurgical and material, and instrumentation and controls engineering
- Safety review
- Quality assurance, audit, and surveillance
- Plant chemistry
- Radiation protection and environmental support
- Fueling and refueling operations support
- Training

- Maintenance support
- Operations support
- Fire protection
- Emergency planning organization
- Outside contractual assistance

If unit personnel are not qualified to address a specific problem, the services of qualified individuals from other functions in the company or an outside consultant are engaged. For example, major contractors, such as the reactor technology vendor or turbine generator manufacturer, provide technical support when equipment modifications or special maintenance problems are considered. Special studies, such as environmental monitoring, may be contracted to qualified consultants. Figure 13.1-201 illustrates the management and technical support organizations for plant operation. See Subsection 13.1.1.3.2 for descriptions of responsibilities and authorities of management positions for organizations providing technical support. Table 13.1-201 shows the estimated number of positions required for each function.

Multiple layers of protection are provided to preserve unit integrity, including organization. Organizationally, operators and other shift members are typically assigned to a specific unit. Physical separation of units helps to minimize wrong unit activities. In addition, unit procedures and programs provide operating staff with methods to minimize human error, including tagging programs, procedure adherence requirements, and training.

13.1.1.2.1 Engineering Support

The engineering support department consists of system engineering, design engineering, engineering performance improvement, and program engineering. The engineering program group includes reactor engineering. These groups are responsible for performing the classical design activities, as well as providing engineering expertise in other areas of new plant sites.

Each engineering group has a functional manager who reports through a nuclear engineering site director to the site vice president. The engineering site director interfaces with the general manager fleet engineering for governance and oversight. See Figure 13.1-201.

The engineering support department is responsible for:

- Supporting plant operations in the engineering areas of mechanical, structural, electrical, thermal-hydraulic, metallurgy and materials, electronic, instrument and control, and fire protection. Priorities for support activities are established based on input from site management with emphasis on issues affecting safe operation of the plant
- Engineering programs
- Supporting procurement, chemical and environmental analysis, and maintenance activities in the plant as requested by the site management
- Performing design engineering of plant modifications
- Maintaining the design basis by updating the record copy of design documents, as necessary, to reflect the actual as-built configuration of the plant
- Accident and transient analyses
- Human factors engineering design process
- Reactor engineering

The site reactor engineering team is supported by the director nuclear fuels. The director nuclear fuels provides technical assistance in the areas of core design, core operations, core thermal limits, and core thermal hydraulics. The director nuclear fuels reports to the general manager fleet engineering.

Engineering work may be contracted to and performed by outside companies in accordance with the Quality Assurance Program Description (QAPD).

Engineering resources are shared between Units 6 & 7. A single management organization oversees the engineering work associated with Units 6 & 7.

13.1.1.2.2 Assessment and Safety Review

Programs are established for reviews and assessments to verify that activities covered by this quality assurance program are performed in compliance with the requirements established, review significant proposed plant changes or tests, verify that reportable events are promptly investigated and corrected, and detect trends which may not be apparent to the day-to-day observer. These programs

are, themselves, reviewed for effectiveness as part of the overall assessment process, as described herein.

Self-assessment (performed by or for the group responsible for the activity being assessed) and independent assessment (performed by the nuclear oversight organization) are used to monitor overall performance, identify anomalous performance and precursors of potential problems, and verify satisfactory resolution of problems. Persons responsible for carrying out these assessments are cognizant of day-to-day activities such that they can act in a management advisory function with respect to the scope of the assessment. Both self-assessments and independent assessments are accomplished using instructions or procedures that provide detail commensurate with the assessed activity's complexity and importance to safety.

The plant maintains on-site review group to review overall plant performance and advise site management on matters related to nuclear safety. Independent reviews are periodically performed of matters involving the safe operation of the fleet of nuclear power plants, with a minimum of one such review being conducted for each generating site each year. The review is supplemented by outside consultants or organizations as necessary to ensure the team has the requisite expertise and competence. Results are documented and reported to responsible management.

13.1.1.2.3 Nuclear Assurance

Safety-related activities associated with the operation of the plant are governed by QA direction described in Chapter 17 and the QAPD. The requirements and commitments contained in the QAPD apply to activities associated with structures, systems, and components that are safety-related and are mandatory and should be implemented, enforced, and adhered to by individuals and organizations. QA requirements are implemented through the use of approved procedures, policies, directives, instructions, or other documents that provide written guidance for the control of quality-related activities and provide for the development of documentation to provide objective evidence of compliance. The QA function includes:

- Maintaining the QAPD
- Coordinating the development of audit schedules
- Audit, surveillance, and evaluation of nuclear division suppliers

- Supporting general QA indoctrination and training for the nuclear unit personnel

The site QA organization is independent of the unit operating line organization. Quality control (QC) inspection/testing activities to support plant operation, maintenance, and outages are independent of the unit operating line organization. QA and QC personnel report to the site quality manager.

Personnel resources of the QA organization are shared among units. A single management organization oversees the QA group for the units.

13.1.1.2.4 Chemistry

A chemistry program is established to monitor and control the chemistry of various plant systems so that corrosion of components and piping is minimized and radiation from corrosion by-products is kept to levels that allow operations and maintenance with radiation doses as low as reasonably achievable.

The chemistry manager is responsible to the plant general manager for maintaining chemistry programs and for monitoring and maintaining the water chemistry of plant systems. The staff of the chemistry department consists of laboratory technicians, support personnel, and supervisors who report to the chemistry manager.

Personnel resources of the chemistry organization are shared between Units 6 & 7. A single management organization oversees the chemistry group for Units 6 & 7.

13.1.1.2.5 Radiation Protection

A radiation protection program is established to protect the health and safety of the surrounding public and the personnel working at the plant. The radiation protection program is described in Chapter 12. The program includes:

- Respiratory protection
- Personnel dosimetry
- Bioassay
- Survey instrument calibration and maintenance
- Radioactive source control

- Effluents and environmental monitoring and assessment
- Radioactive waste shipping
- Radiation work permits
- Job coverage
- Radiation monitoring and surveys

The radiation protection department is staffed by radiation protection technicians, support personnel, and supervisors who report to the radiation protection manager. To provide sufficient organizational freedom from operating pressures, the radiation protection manager reports directly to the plant general manager.

Personnel resources of the radiation protection organization are shared between Units 6 & 7. A single management organization oversees the radiation protection group for Units 6 & 7.

13.1.1.2.6 Fueling and Refueling Support

The function of fueling and refueling is performed by a combination of personnel from various departments, including operations, maintenance, radiation protection, engineering, and reactor technology vendor, or other contractor staff.

Initial fueling and refueling operations are a function of the outage organization.

The work controls manager is responsible for planning and scheduling outages and for refueling support. The manager of refueling support services reports to the work controls manager and is responsible for implementing the refueling outage plan. The work controls manager reports to the plant general manager. The work controls manager interfaces with the work controls corporate functional area manager (CFAM) for governance and oversight.

Personnel resources of the outage and scheduling organization are shared between Units 6 & 7. A single management organization oversees the outage and scheduling group for Units 6 & 7.

13.1.1.2.7 Training and Development

The site training department establishes, maintains, and implements training programs in accordance with applicable plant administrative directives, regulatory requirements, and company operating policies so that unit personnel can meet the performance requirements of their jobs in operations, maintenance, technical support, and emergency response.

The objective of training programs is to provide qualified personnel to safely and efficiently operate and maintain the plant and to provide compliance with the license, Technical Specifications, and applicable regulations. The training department's responsibilities encompass operator initial license training, requalification training, and plant staff training, as well as the plant access training (general employee training) and radiation worker training. The training manager is independent of the operating line organization to provide independence from operating pressures. Nuclear plant training programs are described in Section 13.2.

Personnel resources of the training department are shared between the units. A single management organization oversees the training group for the four nuclear units. The training manager reports functionally to the site vice president. The training manager receives programmatic direction from the director nuclear fleet training.

13.1.1.2.8 Maintenance Support

In support of maintenance activities, planners, schedulers, and parts specialists prepare work packages, acquire proper parts, and develop procedures that provide for the successful completion of maintenance tasks. Maintenance tasks are integrated into the unit schedule for evaluating the operating or safe shutdown risk elements and providing for safe and efficient performance. The maintenance support department head reports to the maintenance manager who reports to the plant general manager.

Personnel of the maintenance support organization are shared between Units 6 & 7. A single management organization oversees the maintenance group for Units 6 & 7.

13.1.1.2.9 Operations Support

The operations support group provides the additional assistance required for the effective achievement of administrative and technical objectives relevant to the

operations department. The operations support supervisor function is provided under the direction of the operations manager. Operations support includes the following programs:

- Operations procedures
- Operations surveillances
- Equipment tagging
- Fire protection testing and surveillance

13.1.1.2.10 Fire Protection

PTN COL 9.5-1

FPL is committed to maintaining a fire protection program as described in Section 9.5. The site vice president is responsible for the fire protection program. Assigning the responsibilities at that level provides the authority to obtain the resources and assistance necessary to meet fire protection program objectives, resolve conflicts, and delegate appropriate responsibility to the fire protection staff. The relationship of the site vice president to other staff personnel with fire protection responsibilities is shown on Figure 13.1-201. Fire protection for the facility is organized and administered by the fire protection supervisor. The site vice president is responsible for the development and implementation of the fire protection program, including development of fire protection procedures, site personnel and fire brigade training, and inspections of fire protection systems and functions. Functional descriptions of position responsibilities are included in appropriate procedures. Unit personnel are responsible for adhering to the fire protection/prevention requirements detailed in Section 9.5.

The Units 6 & 7 project director–new nuclear projects has the lead responsibility for the overall site fire protection during construction for new units prior to implementation of the operational fire protection program. Once the operational fire protection program is implemented the lead responsibility for Units 6 & 7 fire protection program transitions to the site vice president and the Units 6 & 7 operating organization.

Personnel resources of the fire protection organization are shared between Units 6 & 7. A single management organization oversees the fire protection group for Units 6 & 7.

13.1.1.2.11 Emergency Response Organization

PTN COL 13.1-1

The emergency response organization is composed of personnel who have the experience, training, knowledge, and ability necessary to implement actions to protect the public in the case of emergencies. Managers and unit personnel assigned to positions in the emergency response organization support the emergency preparedness organization and emergency plan, as required. Staff members of the emergency preparedness organization administer and orchestrate drills and training to maintain qualification of site staff members and develop procedures to guide and direct the emergency response organization during an emergency. The emergency preparedness manager reports to the site vice president. The site emergency response organization is described in the Emergency Plan.

Resources of the emergency preparedness group are shared between all units at the site. A single management organization oversees the emergency preparedness group for the four nuclear units.

13.1.1.2.12 Outside Contractual Assistance

Contract assistance with vendors and suppliers of services not available from organizations established as part of the utility staff is provided by the sourcing manager. Personnel in the sourcing department perform the necessary functions to contract vendors of special services to perform tasks for which utility staff does not have the experience or equipment required. The sourcing manager reports to the vice president-new nuclear projects.

Resources of the materials, purchasing, and contracts organization are shared between Units 6 & 7. A single management organization oversees the materials, purchasing, and contracts group for Units 6 & 7.

13.1.1.3 Organizational Arrangement

13.1.1.3.1 Executive Management Organization

Executive management is ultimately responsible for execution of activities and functions for the nuclear generating plants. Executive management establishes expectations so that a high level of quality, safety, and efficiency is achieved in aspects of plant operations and support activities through an effective management control system and an organization selected and trained to meet the

above objectives. A high-level chart of the corporate headquarters and nuclear fleet organization is provided in Figure 13.1-203.

Executives and management with direct line of authority for activities associated with plant operation are shown in Figure 13.1-203. Responsibilities of those executives and managers are specified below.

13.1.1.3.1.1 NextEra Energy President and CEO

This position has the ultimate responsibility for the safe and reliable operation of each nuclear unit owned and/or operated by the utility. This position is responsible for the overall direction and management of the corporation and execution of the company policies, activities, and affairs. This position is responsible for directing NextEra Energy's core operational business, including NextEra Energy, Florida Power & Light Company (FPL), and NextEra Energy Resources. This position is assisted in the direction of nuclear operations by the executive vice president nuclear division and chief nuclear officer (CNO) and other executive staff in the nuclear division of the corporation. The CEO is responsible for developing, implementing, and verifying execution of the Quality Assurance Program. Responsibility for implementing the Quality Assurance Program is delegated to the CNO and authority for developing and verifying execution of the program is delegated to the director nuclear assurance.

13.1.1.3.1.2 Executive Vice President Nuclear Division and Chief Nuclear Officer

The executive vice president nuclear division and CNO reports to the CEO through the chief operating officer. This position is responsible for the overall plant nuclear safety and takes the measures needed to provide acceptable performance of the staff in operating, maintaining, and providing technical support to the plant. This position is responsible for oversight of operations at each of the operating nuclear units in the system. This position delegates authority for the nuclear assurance of new nuclear generation through the director–nuclear assurance.

This position is responsible for nuclear operations, nuclear plant support, training, and performance improvement. The CNO implements these responsibilities through the following direct report positions: vice president nuclear fleet technical support and the site vice presidents. It is the responsibility of the CNO to provide guidance and direction so that safety-related activities, including engineering, operations, operations support, maintenance, and planning are performed following the guidelines of the QA program. The CNO has no ancillary

responsibilities that might detract attention from nuclear safety matters. The CNO is designated as the company officer responsible for assuring that defects and noncompliances are reported to the NRC as required by 10 CFR Part 21.

13.1.1.3.1.3 Vice President–Nuclear Fleet Technical Support

The vice president–nuclear fleet technical support reports to the CNO and the vice president CFAM and outage support, the vice president organizational effectiveness and general managers, as assigned in select functional areas, report to this position. This position is responsible for CFAMs, outage support, organizational effectiveness, fleet engineering, issue management, and fleet projects. This position is also the functional interface with nuclear information technology. The organizations that implement some of these responsibilities are assigned to the site vice president(s).

13.1.1.3.1.4 Director Nuclear Assurance

The position reports to the CNO and is responsible for activities that include establishing, maintaining, and interpreting quality assurance practices and policies (including the Quality Assurance Topical Report); managing independent assessment and establishing quality control practices and policies for quality verification activities. The director nuclear assurance has direct access to the CNO for resolution of any areas in question. Additional responsibilities include facilitating actions deemed necessary to prevent unsafe plant conditions or a significant violation of the QA Program; periodically apprising the CNO of the status of the quality assurance program at NextEra Energy facilities and immediately apprising senior management of significant problems affecting quality; and verifying implementation of solutions for significant conditions adverse to quality identified by Nuclear Oversight. Also responsible for establishing the requirements for assessor and inspector certification; and providing for supplier evaluation; the conduct of supplier assessments or surveys; and verification that supplier quality assurance programs comply with NextEra Energy requirements. This position has Stop Work authority at the sites and corporate offices.

13.1.1.3.1.5 Vice President CFAM and Outage Support

The vice president CFAM and outage support reports to the vice president nuclear fleet technical support and is responsible for CFAM activities, including maintenance, operations, work management, safety, and chemistry/radiation protection. In addition, responsibilities include outage planning and execution.

Some responsibilities may be implemented through a general manager reporting to this position.

13.1.1.3.1.6 Vice President Organizational Effectiveness

The vice president organizational effectiveness reports to the vice president nuclear fleet technical support and is responsible for fleet training, licensing, security, emergency preparedness, and performance improvement/ standardization, which includes operating experience, document control, and records management. Some responsibilities may be implemented through a general manager reporting to this position.

13.1.1.3.1.7 General Managers

General managers are assigned to the areas of operations (including operations and emergency preparedness), fleet engineering (including design engineering, probabilistic safety analysis, and nuclear fuel), issue management (including engineering programs and the engineering chief's organization), and fleet projects (including capital projects, project engineering, project control, project implementation, and ISFSI), and general managers report to the vice president nuclear fleet technical support directly, or through another responsible vice president.

13.1.1.3.1.8 Corporate Functional Area Managers

The CFAMs are responsible to institutionalize the governance and oversight principles implemented by the CFAM program. The CFAM is the highest level of authority within a functional area and is implemented for all functional areas identified in the Nuclear Excellence Model. CFAMs employ functional area processes as a means of achieving fleet-wide alignment, teamwork, efficiency, promote achieving, and maintaining the FPL nuclear operational excellence. CFAMs are established in the following functional areas: maintenance, radiation protection, work management, safety & human performance, and operations/ emergency planning/chemistry.

13.1.1.3.1.9 Executive Vice President–Engineering, Construction & Corporate Services

The executive vice president–engineering, construction & corporate services reports to the NextEra Energy president and CEO and is responsible for new nuclear design and construction, construction scheduling and cost control, testing activities, and turnover to operations for new nuclear generation facilities. This

position is responsible for the development and implementation of a construction QA organization and program consistent with company organization and policy.

13.1.1.3.1.10 Vice President–New Nuclear Projects

The vice president–new nuclear projects reports to the executive vice president–engineering, construction and corporate services, and is responsible for the overall safe and efficient licensing, engineering, construction, and preoperational test of new nuclear projects, and for the implementation of quality assurance requirements in the applicable areas specified by the QAPD.

13.1.1.3.1.11 Vice President–Integrated Supply Chain

The vice president integrated supply chain reports to the CEO through the executive vice president–engineering, construction and corporate services is responsible for procurement engineering, coordinating contract activities, negotiating, generating, and issuing procurement documents for required items and services supporting the operation, licensing, maintenance, modification, and inspection of NextEra Energy nuclear plants, and for materials and equipment to support the nuclear division staff. Responsibilities also include the review of procurement documents to assure that technical and quality requirements are incorporated into the procurement documents that it authorizes, performance of receipt inspection to verify that purchased items comply with procurement document requirements, and controlling materials received at each NextEra Energy nuclear plant site in accordance with company policy and procedures.

13.1.1.3.1.12 Vice President and Chief Information Officer

The chief information officer (CIO) reports to the CEO through the vice chairman and chief financial officer. The CIO is responsible for nuclear information management such as computer-related hardware and software acquisition, deployment, maintenance, control and replacement, telecommunications, information/cyber security, and applicable training.

13.1.1.3.1.13 Director of IT Business Solutions IM Nuclear Systems

This position reports to the vice president and CIO with direct interface with the vice president nuclear fleet technical support. The position has functional areas of responsibility that include management of information technology, nuclear cyber security, and computer related hardware/software acquisition. The functions are supported via staff at both corporate and site levels.

13.1.1.3.2 Site Support Organization

13.1.1.3.2.1 Engineering Site Director

The engineering site director is the onsite lead position for engineering and reports functionally to the site vice president and interfaces with the general manager fleet engineering for governance and oversight. The engineering site director is responsible for engineering activities related to the operation or maintenance of the plants and design change implementation support activities, and other functions described in Subsection 13.1.1.2.1. The engineering site director directs functional managers responsible for design engineering, program engineering, system and component engineering, and engineering performance improvement. Program engineering staff includes reactor engineering as described in Subsection 13.1.1.2.1.

Separate management organizations oversee the engineering support for Units 3 & 4 and Units 6 & 7.

13.1.1.3.2.2 Director Nuclear Fleet Security

The director nuclear fleet security is responsible for providing guidance and direction to the nuclear plant security manager at each site on the nuclear security, access authorization, and fitness for duty programs. The director nuclear fleet security reports to the vice president–organizational effectiveness.

13.1.1.3.2.3 Director Plant Support

The director plant support provides staff functions to the entire site for financial services, document services, management of the operating experience, and corrective action. The director plant support is assisted by managers, supervisors, and staff in the following units:

- Integrated supply chain
- Document control services
- Financial services
- Information technology
- Site security services
- Performance improvement

13.1.1.3.2.4 Emergency Preparedness Manager

The emergency preparedness manager is responsible for:

- Coordinating and implementing the plant emergency response plan with state and local emergency plans
- Developing, planning, and executing emergency drills and exercises
- Emergency action level development
- NRC reporting associated with 10 CFR 50.54 (q)

The functional manager in charge of emergency preparedness reports to the site vice president and is responsible for the combined emergency preparedness program for Turkey Point Units 3, 4, 6, and 7.

13.1.1.3.2.5 Training Manager

PTN COL 18.10-1

The training manager is responsible for training programs required for the safe and proper operation and maintenance of the plant, including:

- Operations training programs
- Plant staff training programs
- Plant access training
- Emergency plan training
- Radiation worker training

The training manager may seek assistance from other departments in the company or outside specialists such as educators and manufacturers. The training manager supervises a staff of training supervisors who coordinate the development, preparation, and presentation of training programs for nuclear plant personnel.

The training manager reports to the site vice president and is responsible for the combined training programs for Turkey Point Units 3, 4, 6, and 7.

13.1.1.3.2.6 Director Nuclear Fuels

PTN COL 13.1-1

The director nuclear fuels has overall responsibility for implementation of the special nuclear material (SNM) control and accounting function, develops the methodology and analysis procedures to calculate changes in SNM while burning in the core, and prepares the SNM balance and inventory change reports for annual governmental reports.

13.1.1.4 Qualifications of Technical Support Personnel

PTN COL 18.6-1

The qualifications of managers and supervisors of the technical support organization meet the qualification requirements in education and experience for those described in ANSI/ANS-3.1-1993 (Reference 201) as endorsed and amended by RG 1.8. The qualification and experience requirements of headquarters staff are established in accordance with current corporate nuclear policy and procedure manuals.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

PTN COL 13.1-1

The plant management, technical support, and plant operating organizations are shown in Figure 13.1-201. The on-shift operating organization is presented in Figure 13.1-202, which shows those positions requiring NRC licenses. Additional personnel are required to augment normal staff during outages.

Nuclear plant employees are responsible for reporting problems with plant equipment and facilities. They are required to identify and document equipment problems in accordance with the QA program. QA program requirements as they apply to the operating organization are described in Chapter 17 and the QAPD. Administrative procedures or standing orders include:

- Establishing a QA program for the operational phase
- Preparing procedures necessary to carry out an effective QA program. See Section 13.5 for a description of the unit procedure program

- Establishing a program for review and audit of activities affecting plant safety. See Section 17.5 and the QAPD for a description of unit review and audit programs

- Preparing programs and procedures for rules of practice as described in Section 5.2 of N18.7-1976/ANS-3.2 (Reference 203)

Managers and supervisors in the plant operating organization are responsible for establishing goals and expectations for their organization and for reinforcing behaviors that promote radiation protection. Specifically, managers and supervisors are responsible for the following, as applicable to their position in the plant organization:

- Interface directly with radiation protection staff to integrate radiation protection measures into plant procedures and design documents and into the planning, scheduling, conduct, and assessment of operations and work

- Notify radiation protection personnel promptly when radiation protection problems occur or are identified, take corrective actions, and resolve deficiencies associated with operations, procedures, systems, equipment, and work practices

- Ensure that department personnel receive training and periodic retraining on radiation protection, in accordance with 10 CFR Part 19, so that they are properly instructed and briefed for entry into restricted areas

- Periodically observe and correct, as necessary, radiation worker practices

- Support radiation protection management in implementing the radiation protection program

- Maintain exposures to site personnel ALARA

13.1.2.1.1 Site Vice President

The site vice president directs the efforts of the plant general manager for Units 3 & 4, the plant general manager for Units 6 & 7, the director–plant support for the site, the nuclear engineering site director for Units 3 & 4, the nuclear engineering site director for Units 6 & 7, and the licensing manager for the site and receives input from the site quality manager. The site vice president reports to the CNO.

13.1.2.1.2 Plant General Managers

The plant general managers and the plant general manager's staff are assigned to Units 6 & 7 or Units 3 & 4 and are responsible for overall safe operation of the assigned units. They have control over those onsite activities necessary for safe operation and maintenance of the assigned units, including the following:

- Operations
- Maintenance and modification
- Chemistry and radiochemistry
- Outage management

Additionally, the plant general manager has overall responsibility for occupational and public radiation safety for their assigned units. Radiation protection responsibilities of the plant general manager are consistent with the guidance in RG 8.8 and RG 8.10, including the following:

- Provide management radiation protection policy throughout the plant organization
- Provide an overall commitment to radiation protection by the plant organization
- Interact with and support the radiation protection manager on implementation of the radiation protection program
- Support identification and implementation of cost-effective modifications to plant equipment, facilities, procedures, and processes to improve radiation protection controls and reduce exposures
- Establish plant goals and objectives for radiation protection
- Maintain exposures to site personnel ALARA
- Support timely identification, analysis, and resolution of radiation protection problems (e.g., through the plant corrective action program)
- Provide training to site personnel on radiation protection in accordance with 10 CFR Part 19

- Establish an ALARA committee with delegated authority from the plant general manager that includes, at a minimum, the managers in charge of operations, maintenance, engineering, and radiation protection to help provide for effective implementation of line organization responsibilities for maintaining worker doses ALARA

In the absence of the plant general manager, the onsite individual designated by the plant general manager will be in charge for the duration of the absence. This will normally be the scheduled duty manager. The succession of authority includes the authority to issue standing or special orders, as required.

As described in Subsection 13.1.2.1.3.4, the operations manager is the plant general manager's direct representative for the conduct of operations.

13.1.2.1.2.1 Maintenance Manager

Plant maintenance is performed by the maintenance department mechanical, electrical, and instrumentation and controls (I&C) disciplines. Planning, scheduling, and work package preparation are performed by maintenance support. The functions of this department are to perform preventive and corrective maintenance, equipment testing, and implement modifications as necessary.

The maintenance manager is responsible for the performance of preventive and corrective maintenance and modification activities required to support operations, including compliance with applicable standards, codes, specifications, and procedures. The maintenance manager reports to the plant general manager and provides direction and guidance to the maintenance discipline functional managers and maintenance support staff.

13.1.2.1.2.2 Maintenance Superintendents

The superintendent of each maintenance discipline (mechanical, electrical, I&C, and support) is responsible for maintenance activities in that discipline, including plant modifications. The superintendents provide guidance in maintenance planning and craft supervision. They establish the necessary manpower levels and equipment requirements to perform both routine and emergency maintenance activities, seeking the services of others in performing work beyond the capabilities of the plant maintenance group. Each discipline superintendent is responsible for liaison with other plant staff organizations to facilitate safe operation of the unit. These superintendents report to the maintenance manager.

13.1.2.1.2.3 Maintenance Supervisors

The maintenance supervisors (mechanical, electrical, and I&C) supervise maintenance activities, assist in planning future maintenance efforts, and guide the efforts of the craft workers in their discipline. The maintenance discipline supervisors report to the appropriate maintenance discipline superintendent.

13.1.2.1.2.4 Maintenance Mechanics, Electricians, and I&C Technicians

The discipline craft workers perform electrical and mechanical maintenance, I&C, and support tasks as they are assigned by the discipline supervisors. The craft workers trouble-shoot, inspect, repair, maintain, and modify plant equipment and perform technical specification surveillances on equipment for which they have cognizance. They perform these tasks in accordance with approved procedures and work packages.

13.1.2.1.2.5 Work Control Manager

The work control manager is responsible for:

- Planning and scheduling refueling, maintenance, and forced outages
- Providing direction and guidance to staff members in establishing outage activities
- Minimizing shutdown risk during outages with proper planning and preparation
- Directing activities during outages to provide safe, efficient, and effective outages
- Planning and scheduling online work activities, monitoring the online work process, and risk management

The work control manager is assisted by the outage supervisor and the online supervisor. The work control manager reports to the plant general manager. See Subsection 13.1.1.2.6.

13.1.2.1.2.6 Radiation Protection Manager

The radiation protection manager has the direct responsibility for providing adequate protection of the health and safety of personnel working at the assigned units and members of the public during activities covered in the scope and extent

of the license. Radiation protection responsibilities of the radiation protection manager are consistent with the guidance in RG 8.8 and RG 8.10. They include:

- Managing the radiation protection organization
- Establishing, implementing, and enforcing the radiation protection program
- Providing radiation protection input to facility design and work planning
- Tracking and analyzing trends in radiation work performance and taking the necessary actions to correct adverse trends
- Supporting the plant emergency preparedness program and assigning emergency duties and responsibilities in the radiation protection organization
- Delegating authority to appropriate radiation protection staff to stop work or order an area evacuated (in accordance with approved procedures) when, in his or her judgment, the radiation conditions warrant such an action and such actions are consistent with plant safety
- Developing, implementing, directing, and coordinating the radioactive waste and materials management program for the assigned units

The radiation protection manager reports to the plant general manager and is assisted by the radiation protection supervisors.

13.1.2.1.2.7 Radiation Protection Supervisors

The radiation protection supervisors are responsible for carrying out the day-to-day operations and programs of the radiation protection department as listed in Subsection 13.1.1.2.5.

Radiation protection supervisors report to the radiation protection manager.

13.1.2.1.2.8 Radiation Protection Technicians

Radiation protection technicians directly carry out responsibilities defined in the radiation protection program and procedures. In accordance with Technical Specifications, a radiation protection technician is on site whenever there is fuel in the vessel. See Table 13.1-202.

The following are some of the duties and responsibilities of the radiation protection technicians:

- As delegated authority by the radiation protection manager, stop work or order an area evacuated (in accordance with approved procedures) when, in his or her judgment, the radiation conditions warrant such an action and such actions are consistent with plant safety
- Provide coverage and monitor radiation conditions for jobs potentially involving significant radiation exposure
- Conduct surveys, assess radiation conditions, and establish radiation protection requirements for access to and work in restricted, radiation, high radiation, very high radiation, and airborne radioactivity areas and in areas containing radioactive materials
- Provide control over the receipt, storage, movement, use, and shipment of licensed radioactive materials
- Review work packages, proposed design modifications, and operations and maintenance procedures to facilitate integration of adequate radiation protection controls and dose reduction measures
- Review and oversee implementation of plans for the use of process or other engineering controls to limit the concentrations of radioactive materials in the air
- Provide personnel monitoring and bioassay services
- Maintain, prescribe, and oversee the use of respiratory protection equipment
- Perform assigned emergency response duties

13.1.2.1.2.9 Chemistry Manager

The chemistry manager is responsible for developing, implementing, directing and coordinating the chemistry, radiochemistry, and the nonradiological environmental monitoring programs for the assigned units. This area includes overall operation of the hot lab, cold lab, emergency offsite facility lab, and nonradiological environmental monitoring. This also includes developing, implementing, directing, and coordinating the radioactive liquid effluent injection and radioactive gaseous effluent release control programs, offsite dose calculation manual, and the radiological environmental monitoring program for the assigned units. The chemistry manager is responsible for developing, administering, and implementing procedures and programs that provide for effective compliance with

environmental regulations. The chemistry manager reports to the plant general manager and directly supervises the chemistry supervisors and chemistry technicians.

13.1.2.1.3 Operations Department

Operations activities are conducted with the safety of the public, personnel, and equipment as the overriding priority. The operations department is responsible for:

- Operating unit equipment
- Monitoring and watching safety and nonsafety-related equipment
- Fuel loading
- Providing the nucleus of emergency and firefighting teams

The operations department maintains sufficient licensed and senior licensed operators to staff the control room continuously using a crew rotation system. The operations department is under the authority of the operations manager, who, through the operations supervisor, directs the day-to-day operation of the assigned units.

Specific duties, functions, and responsibilities of key shift members are described in Subsections 13.1.2.1.2.4 through 13.1.2.1.2.8 and in plant administrative procedures and the Technical Specifications. The minimum shift manning requirements are shown in Table 13.1-202.

Some resources of the operations organization are shared between Units 6 & 7.

Administrative and support personnel perform their duties on either unit. To operate or supervise the operation of more than one unit, an operator (senior reactor operator or reactor operator) must hold an appropriate, current license for each unit. A single management organization oversees the operations group for Units 6 & 7. See Table 13.1-201 for estimated number of staff in the operations department for single or multiple-unit sites.

The operations support section is staffed with sufficient personnel to provide support activities for the operating shifts and overall operations department. The following is an overview of the operations organization.

13.1.2.1.3.1 Operations Manager

The operations manager has overall responsibility for the day-to-day operation of the assigned units. The operations manager reports to the plant general manager and is assisted by the shift technical advisors and the operations supervisor. The operations manager or the operations supervisor is licensed as a senior reactor operator.

13.1.2.1.3.2 Operations Supervisor

The operations supervisor, under the direction of the operations manager, is responsible for:

- Conducting shift plant operations in accordance with the operating license, Technical Specifications, and written procedures
- Providing supervision of operating shift personnel for operational shift activities, including those of emergency and firefighting teams
- Coordinating with the operations support superintendent and other plant staff sections
- Verifying that nuclear plant operating records and logs are properly prepared, reviewed, evaluated, and turned over to the operations support superintendent

The operations supervisor is assisted in these areas by the shift manager, who directs the operating shift personnel. The operations supervisor reports to the operations manager.

13.1.2.1.3.3 Operations Support Superintendent

The operations support superintendent, under the direction of the operations manager, is responsible for:

- Directing and guiding plant operations support activities in accordance with the operating license, Technical Specifications, and written procedures
- Supervising operating support personnel, overseeing operations support activities, and coordinating support activities
- Providing for nuclear plant operating records and logs to be turned over to the nuclear records group for maintenance as QA records

- Coordinating operations related to fire protection program activities with the supervisor–fire protection

The operations support superintendent is assisted by the work management, operations procedures, and other support personnel.

13.1.2.1.3.4 Shift Manager

The shift manager is a licensed senior reactor operator responsible for the control room command function, and is the plant general manager's direct management representative for the conduct of operations. As such, the shift manager has the responsibility and authority to direct the activities and personnel at Units 6 & 7 as required to:

- Protect the health and safety of the public, the environment, and personnel on the plant site
- Protect the physical security of the plant
- Prevent damage to site equipment and structures
- Comply with the operating license

The shift manager retains this responsibility and authority until formally relieved of operating responsibilities. Additional responsibilities of the shift manager include:

- Directing nuclear plant employees to report to the plant for response to potential and real emergencies
- Seeking the advice and guidance of the shift technical advisor and others in executing the duties of the shift manager whenever in doubt as to the proper course of action
- Promptly informing responsible supervisors of significant actions affecting their responsibilities
- Participating in operator training, retraining, and requalification activities from the standpoint of providing guidance, direction, and instruction to shift personnel

The shift manager is the senior management on shift and is responsible for Units 6 & 7. The shift manager is assisted in carrying out the above duties by the unit

supervisors in charge on shift and the operating shift personnel. The shift manager reports to the operations supervisor.

13.1.2.1.3.5 Unit Supervisors

The unit supervisors are licensed senior reactor operators. The primary function of the unit supervisors is to administratively support the shift manager so that the command function is not overburdened with administrative duties and to supervise the licensed and non-licensed operators in carrying out the activities directed by the shift manager. Other duties include:

- Being aware of maintenance and testing performed during the shift
- Shutting down the reactor if conditions warrant this action
- Informing the shift manager and other unit management in a timely manner of conditions that may affect public safety, plant personnel safety, or plant capacity or reliability, or cause a hazard to equipment
- Initiating immediate corrective action as directed by the shift manager in any upset situation until assistance, if required, arrives
- Participating in operator training, retraining, and requalification activities from the standpoint of providing guidance, direction, and instruction to shift personnel

The unit supervisors report directly to the shift manager.

13.1.2.1.3.6 Reactor Control Operators

The reactor control operators are licensed reactor operators and report to the unit supervisor. They are responsible for routine plant operations and performance of major evolutions at the direction of the unit supervisor.

Reactor control operator duties include:

- Monitoring control room instrumentation
- Responding to plant or equipment abnormalities in accordance with approved plant procedures
- Directing the activities of non-licensed operators

- Documenting operational activities, plant events, and plant data in shift logs
- Initiating plant shutdowns, scrams, or other compensatory actions when observation of plant conditions indicates that a nuclear safety hazard exists or when approved procedures so direct

Whenever there is fuel in the reactor vessel, at least one reactor control operator is in the control room monitoring the status of the unit at the main control panel. The reactor control operator assigned to the main control panel is designated the operator at the controls and conducts monitoring and operating activities in accordance with the guidance set forth in RG 1.114, which is further described in Subsection 13.1.2.1.4.

13.1.2.1.3.7 Non-Licensed Operators

The non-licensed operators perform routine duties outside the control room as necessary for continuous, safe plant operation, including:

- Assisting in plant startup, shutdown, surveillance, and emergency response by manually or remotely changing equipment operating conditions, placing equipment in service, or securing equipment from service at the direction of the reactor control operator
- Performing assigned tasks in procedures and checklists, such as valve manipulations for plant startup, or in data sheets on routine equipment checks, and making accurate entries according to the applicable procedure, checklist, or data sheet
- Assisting in training new employees and in improving and upgrading their own performance by participating in the applicable sections of the training program

Non-licensed operators include auxiliary operators as shown in Figure 13.1-202.

13.1.2.1.3.8 Shift Technical Advisor

FPL is committed to meeting NUREG-0737 TMI Action Plan item I.A.1.1 for shift technical advisors. The shift technical advisor reports directly to the shift manager and provides advanced technical assistance to the operating shift complement during normal and abnormal operating conditions. The shift technical advisor's responsibilities are detailed in plant administrative procedures as required by TMI Action Plan I.A.1.1 and NUREG 0737 Appendix C. These responsibilities include:

- Activities to monitor core power distribution and critical parameters
- Activities to assist the operating shift with technical expertise during normal and emergency conditions
- The evaluation of Technical Specifications, special reports, and procedural issues

The shift technical advisor primarily contributes to maximizing the safety of operations by independently observing plant status and advising shift supervision of conditions that could compromise plant safety. During transients or accident situations, the shift technical advisor independently assesses plant conditions and provides technical assistance and advice to mitigate the incident and minimize the effect on personnel, the environment, and plant equipment.

A senior reactor operator on shift who meets the qualifications for the combined senior reactor operator/shift technical advisor position specified for Option 1 of Generic Letter 86-04 (Reference 202) may also serve as the shift technical advisor. If this option is used for a shift, then the separate shift technical advisor position may be eliminated for that shift.

13.1.2.1.3.9 Fire Protection Supervisor and Fire Protection Engineer

PTN COL 9.5-1

In the engineering and support unit, the fire protection supervisor is in charge of fire protection and the fire protection staff. The fire protection supervisor is responsible for:

- Fire protection program requirements, including consideration of potential hazards associated with postulated fires, knowledge of building layout, and system design
- Postfire shutdown capability
- Design, maintenance, surveillance, and QA of fire protection features (e.g., detection systems, suppression systems, barriers, dampers, doors, penetration seals, and fire brigade equipment)
- Fire prevention activities (administrative controls and training)
- Fire brigade organization and training

- Prefire planning, including review and updating of prefire plans at least every 2 years

The fire protection supervisor reports through the program engineering manager to the site vice president, who has ultimate responsibility for the fire protection program. Additionally, the fire protection supervisor works with the operations support superintendent to coordinate activities and program requirements with the operations department. The fire protection supervisor is qualified in accordance with ANSI/ANS-3.1-1993, Section 4.4 (Reference 201).

Fire protection program implementation and maintenance are the responsibilities of the fire protection engineer. The fire protection engineer is qualified in accordance with RG 1.189 Revision 1, Regulatory Position 1.6.1.a.

Both the fire protection supervisor and the fire protection engineer are trained and experienced in fire protection and nuclear plant safety or have available personnel who are trained and experienced in fire protection and nuclear plant safety.

13.1.2.1.3.10 Radwaste Operations Lead

PTN COL 13.1-1

This position is responsible for developing, implementing, directing, and coordinating the radwaste activities. This position reports to the operations supervisor.

This position supervises radwaste operators assigned to the radwaste area.

13.1.2.1.4 Conduct of Operations

Unit operations are controlled and/or coordinated through the control room. Maintenance activities, surveillances, and removal from/return to service of structures, systems, and components affecting the operation of the plant may not commence without the approval of senior control room personnel. The rules of practice for control room activities, as described by administrative procedures, which are based on RG 1.114, address the following:

- Position/placement of operator at the controls workstation and the expected area of the control room where most of the unit supervisor's time should be spent

- Definition and outline of “surveillance area” and requirement for continuous surveillance by the operator at the controls
- Relief requirements for operator at the controls and the unit supervisor

In accordance with 10 CFR 50.54:

- Reactivity controls may be manipulated only by licensed operators and senior operators except as allowed for training under 10 CFR Part 55
- Apparatus and mechanisms other than controls that may affect reactivity or power level of the reactor will be operated only with the consent of the operator at the controls or the unit supervisor
- During operation of the facility in modes other than cold shutdown or refueling, a senior operator will be in the control room and a licensed operator or senior operator will be present at the controls

13.1.2.1.5 Operating Shift Crews

Plant administrative procedures are used to implement the required shift staffing. These procedures establish crews with sufficient qualified plant personnel to staff the operational shifts and be readily available in the event of an abnormal or emergency situation. The objective is to operate the plant with the required staff and to develop work schedules that minimize overtime for plant staff members who perform safety-related functions. Work hour limitations are provided in unit procedures. When overtime is necessary, the provisions in the Technical Specifications and the plant administrative procedures apply. Shift crew staffing plans may be modified during refueling outages to accommodate safe and efficient completion of outage work in accordance with the work hour limitations.

The minimum composition of the operating shift crew is contingent on the unit operating status. Position titles, license requirements, and minimum shift manning for various modes of operation are contained in Technical Specifications, administrative procedures, and Table 13.1-202. Routine shift operations staffing is illustrated in Figure 13.1-202.

13.1.2.1.6 Fire Brigade

The plant is designed and the fire brigade is organized to be self-sufficient with respect to firefighting activities. The fire brigade is organized to address fires and related emergencies that could occur. It consists of a fire brigade leader and a

sufficient number of team members to be consistent with the equipment that must be put in service during a fire emergency. A sufficient number of trained and physically qualified fire brigade members are available onsite during each shift. The fire brigade consists of at least five members on each shift. Members of the fire brigade are knowledgeable of building layout and system design. The assigned fire brigade members for any shift do not include the shift manager nor any other members of the minimum shift operating crew necessary for safe shutdown of the unit. It does not include any other personnel required for other essential functions during a fire emergency. Fire brigade members for a shift are designated in accordance with established procedures at the beginning of the shift.

13.1.2.1.7 Reclaimed Water Treatment Facility Manager

This position reports to the site vice president and is responsible for the safe operation and maintenance of the FPL reclaimed water treatment facility.

13.1.3 QUALIFICATION REQUIREMENTS OF NUCLEAR PLANT PERSONNEL

PTN COL 18.6-1

13.1.3.1 Minimum Qualification Requirements

PTN COL 13.1-1

Qualifications of managers, supervisors, operators, and technicians of the operating organization meet the qualification requirements in education and experience for those described in ANSI/ANS-3.1-1993 (Reference 201), as endorsed and amended by RG 1.8.

13.1.3.2 Qualification Documentation

Résumés and/or other documentation of qualification and experience of initial appointees to appropriate management and supervisory positions are available for NRC review after position vacancies are filled.

STD DEP 1.1-1

13.1.4 COMBINED LICENSE INFORMATION ITEM

PTN COL 13.1-1

This COL item is addressed in Subsections 13.1.1 through 13.1.3.

13.1.5 REFERENCES

201. American Nuclear Society, *American National Standard for Selection, Qualification, and Training of Personnel for Nuclear Power Plant*, ANSI/ANS-3.1-1993.

202. U.S. Nuclear Regulatory Commission, *Generic Letter 86-04, Policy Letter, Engineering Expertise on Shift*.

203. American Nuclear Society, *American National Standard for Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants*, N18.7-1976/ANS-3.2.

PTN COL 18.6-1

PTN COL 13.1-1

Table 13.1-201 (Sheet 1 of 3)
Generic Position/Site-Specific Position Cross Reference

Nuclear Function	Function Position – ANSI/ANS-3.1-1993	Section Reference	Nuclear Plant Position (Site-Specific)	Expected Positions Single Unit	Expected Additional Positions Second Unit
Executive Management	Chief Executive Officer		Chief Executive Officer (CEO)	1	—
	Chief Nuclear Officer		Chief Nuclear Officer (CNO)	1	—
	Executive, Nuclear Operations		Executive Vice President and CNO	1	—
	Executive, Nuclear Generation and Development		Executive Vice President–Engineering, Construction, & Corporate Services	1	—
Nuclear Support	Executive, Operations Support		Vice President–Nuclear Fleet Technical Support	1	—
Plant Management	Executive	4.2.1	Site Vice President	1	—
	Plant Manager		Plant General Manager-Units 6 & 7	1	—
Engineering	Executive	4.2.4	General Manager Fleet Engineering	1	—
	Manager		Engineering Site Director-Units 6 & 7	1	—
System Engineering	Functional Manager	4.3.9	System Engineering Manager	1	—
	System Engineer		System Engineers	24	12
Design Engineering	Functional Manager	4.3.9	Design Engineering Manager	1	—
	Design Engineer		Design Engineers	12	6
Engineering Programs	Functional Manager	4.3.9	Operations Support Engineering Manager	2	—
	Programs Engineer		Operations Support Engineers		6
Reactor Engineering	Functional Manager	4.3.9	Reactor Engineering Supervisor	1	—
	Reactor Engineer		Reactor Engineers	3	1
Maintenance	Manager	4.2.3	Maintenance Manager	1	—
Instrumentation and Control	Functional Manager	4.3.4	I&C Maintenance Superintendent	1	—
	Supervisor	4.4.7	I&C Maintenance Supervisor	3	1
	Technician	4.5.3.3	I&C Technicians	22	12
Mechanical	Functional Manager	4.3.6	Mechanical Maintenance Superintendent	2	—
	Supervisor	4.4.9	Mechanical Maintenance Supervisors	2	1
	Technician	4.5.7.2	Mechanics	22	8

PTN COL 18.6-1

PTN COL 13.1-1

Table 13.1-201 (Sheet 2 of 3)
Generic Position/Site-Specific Position Cross Reference

Nuclear Function	Function Position – ANSI/ANS-3.1-1993 Section Reference		Nuclear Plant Position (Site-Specific)	Expected Positions Single Unit	Expected Additional Positions Second Unit
Electrical	Functional Manager	4.3.5	Electrical Maintenance Superintendent	1	—
	Supervisor	4.4.8	Electrical Maintenance Supervisor	2	1
	Technician	4.5.7.1	Electricians	14	6
Support	Functional Manager	4.3	Maintenance Support Superintendent	1	—
Operations	Manager	4.2.2	Operations Manager	1	—
Operations, Plant	Functional Manager	4.3.8	Operations Supervisor	1	1
Operations, Admin	Functional Manager	4.3.8	Operations Support Supervisor	1	—
Operations (On-shift)	Functional Manager	4.4.1	Shift Manager	6	—
	Supervisor	4.4.2	Unit Supervisor	6	6
			Nuclear Watch Engineer	6	6
	Licensed Operator	4.5.1	Reactor Control Operator	12	12
	Non-Licensed Operator	4.5.2	Non-Licensed Operator	36	18
	Shift Technical Supervisor	4.6.2	Shift Technical Advisor	6	—
Operations – Radwaste	Supervisor	4.4	Radwaste Operations Lead	1	—
Fire Protection	Supervisor	4.4	Fire Protection Supervisor	1	—
Radiation Protection	Functional Manager	4.5.3.2	Radiation Protection Manager	1	—
	Supervisor		Radiation Protection Supervisors	3	3
	Technician		Radiation Protection Technicians	18	9
	ALARA specialist		ALARA Supervisors	3	1
	Decon Technician		Utility Workers	6	2
Chemistry	Functional Manager	4.3.2	Chemistry Manager	1	—
	Supervisor	4.4.5	Chemistry Supervisors	4	1
	Technician	4.5.3.1	Chemistry Technicians	18	9
Nuclear Safety Assurance	Manager	4.2	Site Quality Manager	1	—
Licensing	Functional Manager	4.3	Licensing Manager	1	—
	Supervisor		Licensing Supervisor	1	—
	Licensing Engineer		Licensing Engineer	2	1
Corrective Action	Functional Manager	4.3	Performance Improvement Manager	1	—
	Corrective Action Specialist		Analysts	2	2

PTN COL 18.6-1

PTN COL 13.1-1

Table 13.1-201 (Sheet 3 of 3)
Generic Position/Site-Specific Position Cross Reference

Nuclear Function	Function Position – ANSI/ANS-3.1-1993	Section Reference	Nuclear Plant Position (Site-Specific)	Expected Positions Single Unit	Expected Additional Positions Second Unit
Emergency Preparedness	Functional Manager	4.3	Site Emergency Preparedness Manager	1	—
	EP Planner		EP Planner	2	1
Training	Functional Manager	4.3.1	Site Training Manager	1	—
	Supervisor Ops Trng	4.4.4	Operations Training Supervisors	3	—
	Ops Training Instructor		Operations Training Instructors	2	—
	Supervisor Tech. Staff/ Maint		Maintenance & Technical Training	9	4
	TrngTech Staff/Maint. Instructors		Supervisors	2	—
			Tech/Maint Instructors	8	4
Purchasing and Contracts	Functional Manager	4.3	Nuclear Materials Manager	1	—
Security	Functional Manager	4.3	Security Manager	1	—
Planning and Scheduling	Functional Manager	4.3	Work Control Manager	1	—
	Functional Manager	4.3	Outage Supervisor	1	1
	Supervisor	4.4	Online Supervisor	1	1
			Work Week Managers	6	6
Quality Assurance	Functional Manager	4.3.7	Site Quality Manager	1	—
	Supervisor	4.4.13	Quality Assurance Supervisors	2	—
	QA Auditor		QA Auditors	3	3
	Supervisor	4.4.13	QC Supervisor	1	—
	QC Inspector	4.4.11	QC Inspectors	4	2
Startup testing	Supervisor	4.4.12	Startup Manager	2	—
	Startup Test Engineer Supervisor		Startup Test Supervisor	5	—
	Preop. Test Engineer		Startup Engineers	25	—

PTN COL 13.1-1

PTN COL 18.6-1

Table 13.1-202
Minimum On-Duty Operations Shift Organization for Two-Unit Plant

Units Operating	Two Units Two Control Rooms
All Units Shutdown	1 SM (SRO) 2 RO 3 NLO
One Unit Operating[(a)]	1 SM (SRO) 2 SRO 3 RO 4 NLO
Two Units Operating[(a)]	1 SM (SRO) 2 SRO 3 RO 4 NLO
SM – Shift Manager SRO – Licensed Senior Reactor Operator	RO – Licensed Reactor Operator NLO – Non-Licensed Operator

(a) Operating modes other than cold shutdown or refueling.

Notes:

1. In addition, one Shift Technical Advisor (STA) is assigned per shift during plant operation. A shift manager or another SRO on shift, who meets the qualifications for the combined Senior Reactor Operator/Shift Technical Advisor position, as specified for option 1 of Generic Letter 86-04, (Reference 202) the commission's policy statement on engineering expertise on shift, may also serve as the STA. If this option is used for a shift, then the separate STA position may be eliminated for that shift.

2. In addition to the minimum shift organization above, during refueling a licensed senior reactor operator or senior reactor operator limited (fuel handling only) is required to directly supervise any core alteration activity.

3. A shift manager/supervisor (SRO licensed for each unit that is fueled), will be onsite at all times when at least one unit is loaded with fuel.

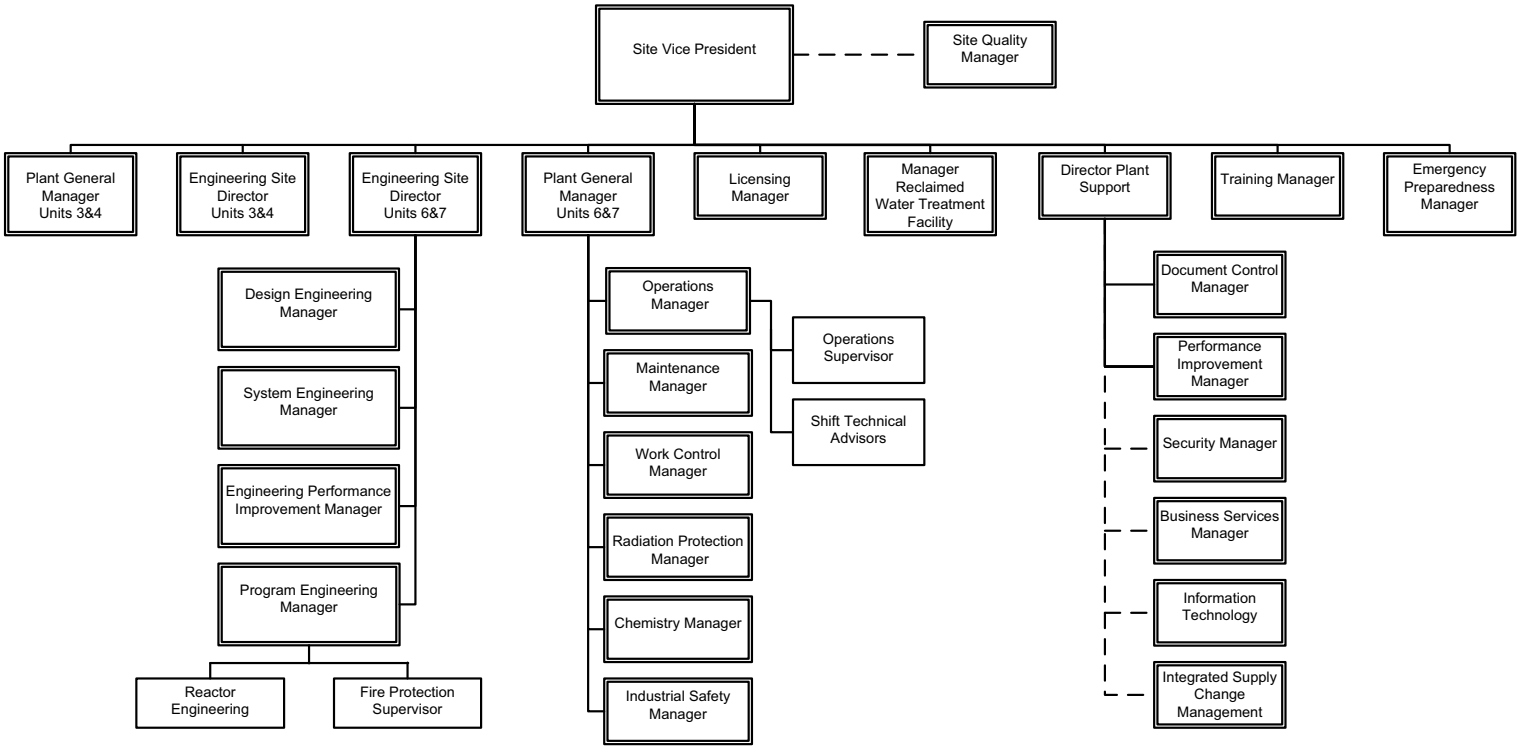
4. A radiation protection technician will be onsite at all times when there is fuel in a reactor.

5. A chemistry technician will be onsite during plant operation in modes other than cold shutdown or refueling.

6. To operate, or supervise the operation of more than one unit, an operator (SRO or RO) must hold an appropriate, current license for each unit.

PTN COL 13.1-1

Figure 13.1-201 Plant Management Organization



PTN COL 13.1-1

Figure 13.1-202 Shift Operations Organization

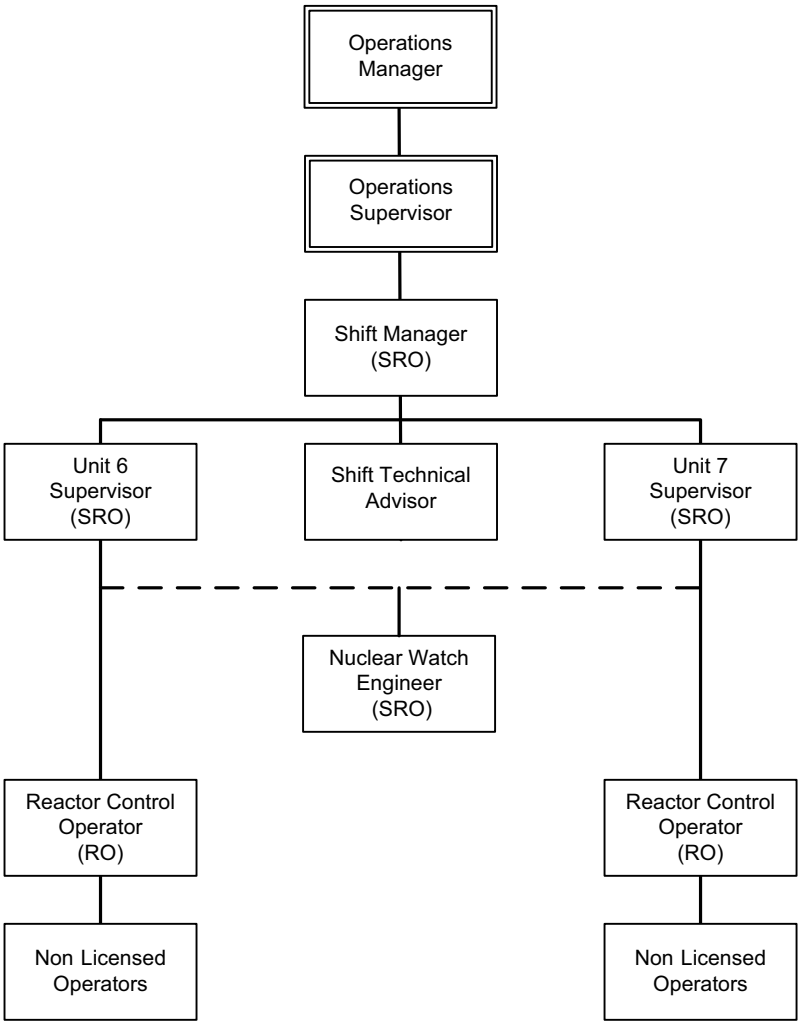
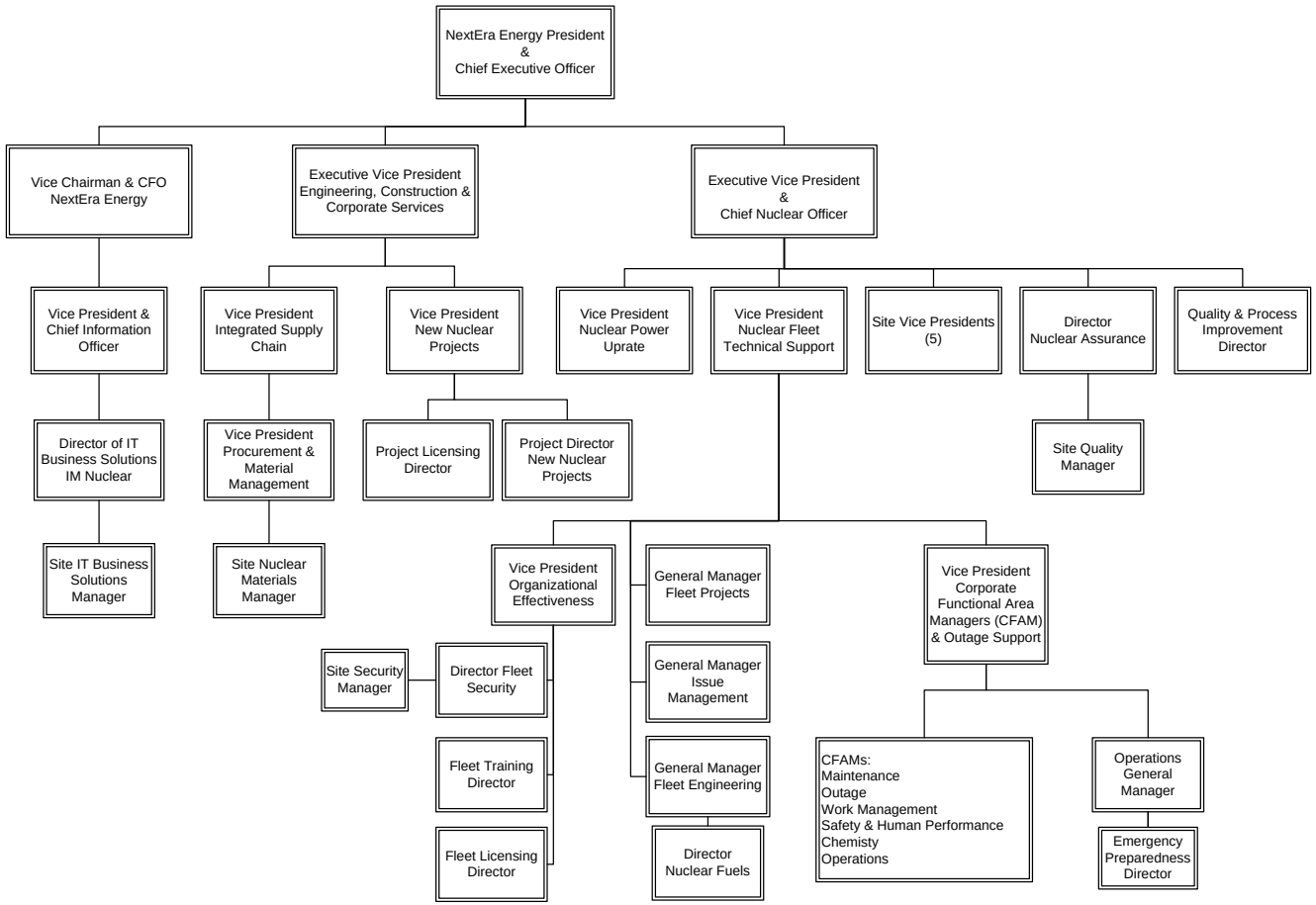


Figure 13.1-203 Corporate and Engineering Organization

PTN COL 13.1-1



13.2 TRAINING

This section of the referenced DCD is incorporated by reference, with the following departures and/or supplements.

STD COL 13.2-1

This section incorporates by reference NEI 06-13A, Template for an Industry Training Program Description. See Table 1.6-201.

Table 13.4-201 provides milestones for training implementation.

STD COL 18.10-1

Operators involved in the Human Factors Engineering Verification and Validation (V&V) Program receive additional training specific to the task of performing V&V. A systematic approach to training is incorporated in developing this training program along with input from WCAP-14655, Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel (Reference 201).

13.2.1 COMBINED LICENSE INFORMATION ITEM

STD COL 13.2-1

This COL Item is addressed in Section 13.2.

13.2.2 REFERENCES

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201. Westinghouse, *Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel*, WCAP-14655, Rev. 1, August 1996.

13.3 EMERGENCY PLANNING

This section of the referenced DCD is incorporated by reference, with the following departures and/or supplements.

STD COL 13.3-1 The emergency planning information is submitted to the Nuclear Regulatory Commission as a separate licensing document and is incorporated by reference (see Table 1.6-201).

Post-72 hour support actions, as discussed in DCD Subsections 1.9.5.4 and 6.3.4, are addressed in DCD Subsections 6.2.2, 8.3, and 9.1.3. Provisions for establishing post-72 hour ventilation for the main control room, instrumentation and control rooms, and dc equipment rooms are established in operating procedures.

STD COL 13.3-2 The emergency plan describes the plans for coping with emergency situations, including communications interfaces and staffing of the emergency operations facility.

STD SUP 13.3-1 Table 13.4-201 provides milestones for emergency planning implementation.

13.3.1 COMBINED LICENSE INFORMATION ITEM

STD COL 13.3-1 This COL Item is addressed in Section 13.3.

STD COL 13.3-2 This COL Item is addressed in Section 13.3 and in the Emergency Plan.

13.4 OPERATIONAL PROGRAMS

This section of the referenced DCD is incorporated by reference, with the following departures and /or supplements.

STD COL 13.4-1 Operational programs are specific programs that are required by regulations. Table 13.4-201 lists each operational program, the regulatory source for the program, the section of the FSAR in which the operational program is described, and the associated implementation milestone(s).

13.4.1 COMBINED LICENSE INFORMATION ITEM

STD COL 13.4-1 This COL Item is addressed in Section 13.4.

13.4.2 REFERENCES

201. American Society of Mechanical Engineers, ASME Boiler and Pressure Vessel Code, *Section XI — Rules for Inservice Inspection of Nuclear Power Plant Components*.

202. American Society of Mechanical Engineers, *ASME OM Code for the Operation and Maintenance of Nuclear Power Plants*.

STD COL 13.4-1

Table 13.4-201 (Sheet 1 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
1.	Inservice Inspection Program	10 CFR 50.55a(g)	5.2.4, 5.4.2.5, 6.6	Prior to Commercial service	10 CFR 50.55a(g), ASME XI IWA 2430(b) (Reference 201)
2.	Inservice Testing Program	10 CFR 50.55a(f), 10 CFR Part 50, Appendix A	3.9.6, 5.2.4	After generator online on nuclear heat[(a)]	10 CFR 50.55a(f), ASME OM Code (Reference 202)
3.	Environmental Qualification Program	10 CFR 50.49(a)	3.11	Prior to initial fuel load	License Condition
4.	Preservice Inspection Program	10 CFR 50.55a(g)	5.2.4, 5.4.2.5, 6.6	Completion prior to initial plant start-up	10 CFR 55a(g), ASME Code Section XI IWB-2200(a) (Reference 201)
5.	Reactor Vessel Material Surveillance Program	10 CFR 50.60, 10 CFR 50.61, 10 CFR Part 50, Appendix H	5.3.2.6	Prior to initial criticality	License Condition
6.	Preservice Testing Program	10 CFR 50.55a(f)	3.9.6	Prior to initial fuel load	License Condition
7.	Containment Leakage Rate Testing Program	10 CFR 50.54(o), 10 CFR Part 50, Appendix A (GDC 52), 10 CFR Part 50, Appendix J	6.2.5.1	Prior to initial fuel load	License Condition
8.	Fire Protection Program (portions applicable to radioactive material)	10 CFR 50.48 10 CFR 30.32 10 CFR 40.31 10 CFR 70.22	9.5.1.8	Prior to receipt of fuel onsite Prior to initial fuel load Prior to initial receipt of byproduct, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18)	License Condition 10 CFR 30.32(a) 10 CFR 40.31(a) 10 CFR 70.22(a)

STD COL 13.4-1

Table 13.4-201 (Sheet 2 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
9.	Process and Effluent Monitoring and Sampling Program:				
	Radiological Effluent Technical Specifications/Standard Radiological Effluent Controls	10 CFR 20.1301 and 20.1302, 10 CFR 50.34a, 10 CFR 50.36a, 10 CFR Part 50, Appendix I, Section II and IV	11.5	Prior to initial fuel load	License Condition
	Offsite Dose Calculation Manual	Same as above	11.5	Prior to initial fuel load	License Condition
	Radiological Environmental Monitoring Program	Same as above	11.5	Prior to initial fuel load	License Condition
	Process Control Program	Same as above	11.4	Prior to initial fuel load	License Condition
10.	Radiation Protection Program (including ALARA principle)	10 CFR 20.1101 10 CFR 20.1406	12.1 12.5		License Condition
	• Radioactive Source Control (assignment of RP Supervisor) • Assignment of RP Supervisor • Minimization of Contamination			1. Prior to initial receipt of byproduct, source, or special nuclear materials (excluding Exempt Quantities as descr bed in 10 CFR 30.18)	
	• Personnel Dosimetry • Radiation Monitoring and Surveys • Radiation Work Permits			2. Prior to receipt of fuel onsite	
	• Assignment of RP Manager • Respiratory Protection • Bioassay • Effluents and Environmental Monitoring and Assessment • Job Coverage			3. Prior to initial fuel load	
	• Radioactive Waste Shipping			4. Prior to first shipment of radioactive waste	

STD COL 13.4-1

Table 13.4-201 (Sheet 3 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
11.	Non-Licensed Plant Staff Training Program (portions applicable to radioactive material)	10 CFR 50.120 10 CFR 30.32 10 CFR 40.31 10 CFR 70.22	13.2	18 months prior to scheduled date of initial fuel load Prior to initial receipt of byproduct, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18)	10 CFR 50.120(b) 10 CFR 30.32(a) 10 CFR 40.31(a) 10 CFR 70.22(a)
12.	Reactor Operator Training Program	10 CFR 55.13, 10 CFR 55.31, 10 CFR 55.41, 10 CFR 55.43, 10 CFR 55.45	13.2	18 months prior to scheduled date of initial fuel load	License Condition
13.	Reactor Operator Requalification Program	10 CFR 50.34(b), 10 CFR 50.54(i), 10 CFR 55.59	13.2	Within 3 months after the date the Commission makes the finding under 10 CFR 52.103(g)	10 CFR 50.54 (i-1)
14.	Emergency Planning	10 CFR 50.47, 10 CFR Part 50, Appendix E	13.3	Full participation exercise conducted within 2 years of scheduled date for initial loading of fuel. Onsite exercise conducted within 1 year before the schedule date for initial loading of fuel Applicant's detailed implementing procedures for its emergency plan submitted at least 180 days prior to scheduled date for initial loading of fuel.	10 CFR Part 50, Appendix E, Section IV.F.2.a(ii) 10 CFR Part 50, Appendix E, Section IV.F.2.a(ii) 10 CFR Part 50, Appendix E, Section V

STD COL 13.4-1

Table 13.4-201 (Sheet 4 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
15.	Security Program:				
	Physical Protection Program (applicable to protection of special nuclear material prior to the protected area being declared operational)	10 CFR 73.1 10 CFR 73.67	13.5.2.2.8 13.6	180 days prior to initial receipt of new fuel or non-fuel special nuclear material	10 CFR 73.1(a) 10 CFR 73.67
	Physical Security Program	10 CFR 73.55(b); 10 CFR 73.55(c)(3); 10 CFR 73.56; 10 CFR 73.57;	13.6	Prior to receipt of fuel onsite (protected area)	10 CFR 73.55(a)(4)
	Safeguards Contingency Program	10 CFR 73.55(c)(5); 10 CFR 73.55(k); 10 CFR Part 73, Appendix C	13.6	Prior to receipt of fuel onsite (protected area)	10 CFR 73.55(a)(4)
	Training and Qualification Program	10 CFR 73.55(c)(4); 10 CFR 73.55(d)(3); 10 CFR Part 73, Appendix B	13.6	Prior to receipt of fuel onsite (protected area)	10 CFR 73.55(a)(4)
16.	Quality Assurance Program – Operation	10 CFR 50.54(a), 10 CFR Part 50, Appendix A (GDC 1), 10 CFR Part 50, Appendix B	17.5	COL issuance	10 CFR 50.54(a)(1)
17.	Maintenance Rule	10 CFR 50.65	17.6	Prior to fuel load authorization per 10 CFR 52.103(g)	10 CFR 50.65(a)(1)
18.	Motor-Operated Valve Testing	10 CFR 50.55a(b)(3)(ii)	3.9.6.2.2	Prior to initial fuel load	License Condition
19.	Initial Test Program	10 CFR 50.34, 10 CFR 52.79(a)(28)	14.2	Prior to the first construction test being conducted for the Construction Test Program Prior to the first preoperational test for the Preoperational Test Program Prior to initial fuel load for the Startup Test Program	License Condition

STD COL 13.4-1

Table 13.4-201 (Sheet 5 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
20.	Fitness for Duty (FFD) Program for Construction (workers and first-line supervisors)	10 CFR 26.4(f)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subpart K
	FFD Program for Construction (management and oversight personnel)	10 CFR 26.4(e)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A–H, N, and O
	FFD Program for Security Personnel	10 CFR 26.4(e)(1)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A–H, N, and O
		10 CFR 26.4(a)(5) or 26.4(e)(1)		Prior to the earlier of: A. Licensee's receipt of SNM in the form of fuel assemblies, or B. Establishment of a protected area, or C. The 10 CFR 52.103(g) finding	10 CFR Part 26, Subparts A–I, N, and O
	FFD Program for FFD Program personnel	10 CFR 26.4(g)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A, B, D–H, N, O, and C per licensee's discretion
	FFD Program for persons required to physically report to the Technical Support Center (TSC) or Emergency Operations Facility (EOF)	10 CFR 26.4(c)	13.7	Prior to the conduct of the first full-participation emergency preparedness exercise under 10 CFR Part 50, App. E, Section F.2.a	10 CFR Part 26, Subparts A–I, N, and O, except for §§26.205–209
	FFD Program for Operation	10 CFR Part 26.4(a) and (b)	13.7	Prior to the earlier of: A. Establishment of a protected area, or B. The 10 CFR 52.103(g) finding	10 CFR Part 26, Subparts A–I, N, and O, except for individuals listed in §26.4(b), who are not subject to §§26.205–209

STD COL 13.4-1

Table 13.4-201 (Sheet 6 of 6)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
21.	Cyber Security Program	10 CFR 73.54(b); 10 CFR 73.55(b)(8); 10 CFR 73.55(c)(6)	13.6	Prior to receipt of fuel onsite (protected area)	10 CFR 73.55(a)(4)
22.	SNM Material Control and Accounting Program	10 CFR 74, Subpart B (§§ 74.11 – 74.19, excl. § 74.17)	13.5.2.2.9	Prior to receipt of special nuclear material.	LIcense Condition

(a) Inservice Testing Program will be fully implemented by generator on line on nuclear heat. Appropriate portions of the program are implemented as necessary to support the system operability requirements of the technical specifications

13.5 PLANT PROCEDURES

This section of the referenced DCD is incorporated by reference, with the following departures and/or supplements.

STD DEP 1.1-1

DCD Subsection 13.5.1, Combined License Information, is renumbered in this FSAR section to 13.5.3.

STD COL 13.5-1

This section of the FSAR describes the administrative and other procedures that are not described in the DCD that the operating organization (plant staff) uses to conduct the routine operating, abnormal, and emergency activities in a safe manner.

The Quality Assurance Program Description (QAPD), as presented in Section 17.5, describes procedural document control, record retention, adherence, assignment of responsibilities, and changes.

Procedures are identified in this section by topic, type, or classification in lieu of the specific title and represent general areas of procedural coverage.

Procedures are issued prior to fuel load to allow sufficient time for plant staff familiarization and to develop operator licensing examinations.

The format and content of procedures are controlled by the applicable AP1000 Writer's Guideline.

Each procedure is sufficiently detailed for an individual to perform the required function without direct supervision, but does not provide a complete description of the system or plant process. The level of detail contained in the procedure is commensurate with the qualifications of the individual normally performing the function.

Procedures are developed consistent with guidance described in DCD Section 18.9, "Procedure Development," and with input from the human factors engineering process and evaluations.

13.5.1 ADMINISTRATIVE PROCEDURES

This section describes administrative procedures that provide administrative control over activities that are important to safety for the operation of the facility.

Procedures outline the essential elements of the administrative programs and controls as described in ANSI/ANS 3.2-1988 (Reference 201) and in Section 17.5. These procedures are organized such that the program elements are prescribed in documents normally referred to as administrative procedures. Regulatory and industry guidance for the appropriate format, content, and typical activities delineated in written procedures is implemented as appropriate.

Administrative procedures contain adequate programmatic controls to provide effective interface among organizational elements. This includes contractor and owner organizations providing support to the station operating organization.

A Writer's Guideline promotes the standardization and application of human factors engineering principles to procedures. The Writer's Guideline establishes the process for developing procedures that are complete, accurate, consistent, and easy to understand and follow. The Writer's Guideline provides objective criteria so that procedures are consistent in organization, style, and content. The Writer's Guideline includes criteria for procedure content and format, including the writing of action steps and the specification of acceptable acronym lists and acceptable terms to be used.

Procedure maintenance and control of procedure updates are performed in accordance with the QAPD, as described in Section 17.5.

The administrative programs and associated procedures developed in the pre-COL phase are described in Table 13.5-201 (for future designation as historical information).

The plant administrative procedures provide procedural instructions for the following:

- Procedures review and approval.
- Equipment control procedures — These procedures provide for control of equipment, as necessary, to maintain personnel and reactor safety, and to avoid unauthorized operation of equipment.
- Control of maintenance and modifications.

- Crane operation procedures — Crane operators who operate cranes over fuel pools are qualified and conduct themselves in accordance with ANSI B30.2 (Chapter 2-3), “Overhead and Gantry Cranes” (Reference 202).
- Temporary changes to procedures.
- Temporary procedure issuance and control.
- Special orders of a temporary or self-canceling nature.

PTN COL 13.5-1

- Standing orders to shift personnel, including the authority and responsibility of the shift manager, unit supervisor, reactor control operator, and shift technical advisor

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STD COL 13.5-1

- Manipulation of controls and assignment of shift personnel to duty stations per the requirements of 10 CFR 50.54 (i), (j), (k), (l), and (m) including delineation of the space designated for the “At the Controls” area of the control room
- Shift relief and turnover procedures
- Fitness for Duty
- Control Room access
- Working hour limitations
- Feedback of design, construction, and applicable important industry and operating experience
- Shift Manager administrative duties
- Verification of correct performance of operational activities
- A vendor interface program that provides vendor information for safety related components is incorporated into plant documentation
- Fire protection program implementation

- A process for implementing the safety/security interface requirements of 10 CFR 73.58

PTN COL 13.5-1

A process is in effect at the time of issuance of the combined license and was developed using NRC endorsed industry guidance. This process is used to manage safety/security interface while the security procedures and emergency plan implementing procedures are being developed and implemented.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Operating and Emergency Operating Procedures

This information is addressed in the DCD.

13.5.2.2 Maintenance and Other Operating Procedures

The QAPD, as described in Section 17.5, provides guidance for procedural adherence. Regulatory and industry guidance for the appropriate format, content, and typical activities delineated in written procedures is implemented as appropriate.

13.5.2.2.1 Plant Radiation Protection Procedures

The plant radiation protection program is contained in procedures. Procedures are developed and implemented for such things as: maintaining personnel exposures, plant contamination levels, and plant effluents ALARA; monitoring both external and internal exposures of workers, considering industry-accepted techniques; routine radiation surveys; environmental monitoring in the vicinity of the plant; radiation monitoring of maintenance and special work activities; evaluation of radiation protection implications of proposed modifications; establishing quality assurance requirements applicable to the radiation protection program; and maintaining radiation exposure records of workers and others.

13.5.2.2.2 Emergency Preparedness Procedures

A discussion of emergency preparedness procedures can be found in the Emergency Plan.

13.5.2.2.3 Instrument Calibration and Test Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for instrumentation calibration and testing.

13.5.2.2.4 Chemistry Procedures

Procedures provided for chemical and radiochemical control activities include the nature and frequency of sampling and analyses; instructions for maintaining fluid quality within prescribed limits; the use of control and diagnostic parameters; and limitations on concentrations of agents that could cause corrosive attack, foul heat transfer surfaces or become sources of radiation hazards due to activation.

Procedures are also provided for the control, treatment, and management of radioactive wastes and control of radioactive calibration sources.

13.5.2.2.5 Radioactive Waste Management Procedures

Procedures for the operation of the radwaste processing systems provide for the control, treatment, and management of onsite radioactive wastes. Procedural controls are in place for radiological releases.

PTN COL 13.5-1

As required by License Condition, operating procedures that include provisions to assure that A_2 quantities for radionuclides specified in Appendix A to 10 CFR Part 71 are not exceeded will be developed, implemented and maintained prior to initial fuel load. Procedural controls limit the radionuclide inventory to less than the A_2 limit in each of the three (3) monitor tanks, and in each of up to three (3) mobile radwaste processing systems. Procedures also ensure that any additional equipment to be located in the radwaste building is limited to A_2 quantities. Spent media transfer from a mobile radwaste processing system located in the radwaste building is procedurally controlled such that spent media transfer and packaging for offsite shipment must be complete prior to placing the mobile radwaste processing system back into service. The procedures also ensure that the total cumulative source term of unpackaged wastes, including liquid waste, wet waste, solid waste, gaseous waste, activated or contaminated metals and components, and contaminated waste present at any time in the radwaste building is limited consistent with RG 1.143, Revision 2, unmitigated radiological release criteria (as revised by Standard Review Plan 11.2, SRP Acceptance Criterion 3), so that an unmitigated release, occurring over a two hour time period, would not result in a dose of greater than 100 millirem at the protected area boundary, or an unmitigated exposure, occurring over a two hour time period, would not result in a dose of greater than 5 rem to site personnel located 10 feet from the total

cumulative radioactive inventory. The unmitigated, unshielded worker dose is calculated at 10 feet from the source. Unlimited worker occupancy workstations and low dose rate waiting areas are located no closer than 10 feet from a mobile radwaste processing system or a waste monitor tank. The liquid radwaste system is discussed in Section 11.2.

13.5.2.2.6 Maintenance, Inspection, Surveillance, and Modification Procedures

13.5.2.2.6.1 Maintenance Procedures

Maintenance procedures describe maintenance planning and preparation activities. Maintenance procedures are developed considering the potential impact on the safety of the plant, license limits, availability of equipment required to be operable, and possible safety consequences of concurrent or sequential maintenance, testing or operating activities.

Maintenance procedures contain sufficient detail to permit the maintenance work to be performed correctly and safely. Procedures include provisions for conducting and recording results of required tests and inspections, if not performed and documented under separate test and inspection procedures. References are made to vendor manuals, plant procedures, drawings, and other sources as applicable.

Instructions are included, or referenced, for returning the equipment to its normal operating status. Testing is commensurate with the maintenance that has been performed. Testing may be included in the maintenance procedure or be covered in a separate procedure.

The preventive maintenance program, including preventive and predictive procedures, as appropriate for structures, systems and components, prescribes the frequency and type of maintenance to be performed. An initial program based on service conditions, experience with comparable equipment and vendor recommendations is developed prior to fuel loading. The program is revised and updated as experience is gained with the equipment. To facilitate this, equipment history files are created and kept current. The files are organized to provide complete and easily retrievable equipment history.

13.5.2.2.6.2 Inspection Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for inspections.

13.5.2.2.6.3 Modification Procedures

Plant modifications and changes to setpoints are developed in accordance with approved procedures. These procedures control necessary activities associated with the modifications such that they are carried out in a planned, controlled, and orderly manner. For each modification, design documents such as drawings, equipment and material specifications, and appropriate design analyses are developed or the as-built design documents are utilized. Separate reviews are conducted by individuals knowledgeable in both technical and QA requirements to verify the adequacy of the design effort.

Proposed modification(s) which involve a license amendment or a change to Technical Specifications are processed as proposed license amendment request(s).

Plant procedures impacted by modifications are changed prior to declaring the system operable to reflect revised plant conditions; and cognizant personnel who are responsible for operating and maintaining the modified equipment are adequately trained.

13.5.2.2.7 Material Control Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for material control.

13.5.2.2.8 Security Procedures

A discussion of security procedures is provided in the Security Plan.

PTN COL 13.5-1 The Special Nuclear Material (SNM) Physical Protection Program Description describes the 10 CFR Part 70 required protection program in effect for the period of time during which new fuel as SNM or non-fuel SNM is received and stored in a controlled access area (CAA), in accordance with the requirements of 10 CFR 73.67.

The New Fuel Shipping Plan addresses the applicable 10 CFR 73.67 requirements in the event that unirradiated new fuel assemblies or components are returned to the supplying fuel manufacturer(s) facility.

13.5.2.2.9 Special Nuclear Material (SNM) Material Control and Accounting Procedures

A material control and accounting system consisting of special nuclear material accounting procedures is utilized to delineate the requirements, responsibilities, and methods of special nuclear material control from the time special nuclear material is received until it is shipped from the plant. These procedures provide detailed steps for SNM shipping and receiving, inventory, accounting, and preparing records and reports. The Special Nuclear Material (SNM) Material Control and Accounting (MC&A) Program description is submitted to the Nuclear Regulatory Commission as a separate licensing basis document.

STD DEP 1.1-1

13.5.3 COMBINED LICENSE INFORMATION ITEM

STD COL 13.5-1

Information for this COL item is addressed in Section 13.5.

13.5.4 REFERENCES

201. American National Standards Institute/American Nuclear Society, *Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants*, ANSI/ANS 3.2-1988.

202. American National Standards Institute/American Nuclear Society, *Overhead and Gantry Cranes*, B30.2, Chap. 2-3.

Table 13.5-201
Pre-COL Phase Administrative Programs and Procedures

STD COL 13.5-1

(This table is included for future designation as historical information.)

- Design/Construction Quality Assurance Program
- Reporting of Defects and Noncompliance, 10 CFR Part 21 Program
- Design Reliability Assurance Program

13.6 SECURITY

This section of the referenced DCD is incorporated by reference, with the following departures and/or supplements.

STD COL 13.6-1
STD COL 13.6-5

The Security Plan consists of the Physical Security Plan, the Training and Qualification Plan, and the Safeguards Contingency Plan. The Security Plan is submitted to the Nuclear Regulatory Commission as a separate licensing document to fulfill the requirements of 10 CFR 52.79(a)(35) and 52.79(a)(36) and is incorporated by reference (see Table 1.6-201). The Security Plan meets the requirements contained in 10 CFR Part 73 and will be maintained in accordance with the requirements of 10 CFR 52.98. The Plan is categorized as Security Safeguards Information and is withheld from public disclosure pursuant to 10 CFR 73.21.

The Cyber Security Plan is submitted to the Nuclear Regulatory Commission as a separate licensing document to fulfill the requirements contained in 10 CFR 52.79(a)(36) and 10 CFR 73.54 and is incorporated by reference (see Table 1.6-201). The Cyber Security Plan will be maintained in accordance with the requirements of 10 CFR 52.98. The Plan is withheld from public disclosure pursuant to 10 CFR 2.390.

Table 13.4-201 provides milestones for security program and cyber security program implementation.

13.6.1 COMBINED LICENSE INFORMATION ITEMS

STD COL 13.6-1

Information for the Security Plan portion of this COL item is addressed in Section 13.6.

Information for the Physical Security ITAAC portion of this COL item is addressed in Section 14.3.2.3.2.

STD COL 13.6-5

Information for the cyber security program portion of this COL item is addressed in Section 13.6.

13.6.2 REFERENCES

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201. Not Used.

STD DEP 1.1-1 DCD Section 13.7 is redistributed to include DCD Section 13.7 references 7, 8, and 10 with COLA FSAR Subsection 13.5.4 and DCD Section 13.7 references 2, 3, and 4 with COLA FSAR Subsection 13.6.2.

Add the following new section after DCD Section 13.6.

13.7 FITNESS FOR DUTY

STD SUP 13.7-1 The Fitness for Duty Program (FFD) is implemented and maintained in multiple and progressive phases dependent on the activities, duties, or access afforded to certain individuals at the construction site. In general, two different FFD programs will be implemented: a construction FFD program and an operations FFD program. The construction and operations phase programs are illustrated in Table 13.4-201.

The construction FFD program is consistent with NEI 06-06 (Reference 201). NEI 06-06 applies to persons constructing or directing the construction of safety- and security-related structures, systems, or components performed onsite where the new reactor will be installed and operated. Management and oversight personnel, as further described in NEI 06-06, and security personnel prior to the receipt of special nuclear material in the form of fuel assemblies (with certain exceptions) will be subject to the operations FFD program that meets the requirements of 10 CFR Part 26, Subparts A through H, N, and O. At the establishment of a protected area, all persons who are granted unescorted access will meet the requirements of an operations FFD program. Prior to issuance of a Combined License, the construction FFD program at a new reactor construction site for those subject to Subpart K will be reviewed and revised as necessary should substantial revisions occur to either NEI 06-06 following NRC endorsement or the requirements of 10 CFR Part 26.

PTN SUP 13.7-1 The following site-specific information is provided:

- The FFD program for the construction site, as defined in NEI 06-06, will be administered under an FPL-approved EPC contractor program. The 10 CFR Part 26 requirements are implemented for the construction site area based on the descriptions provided in Table 13.4-201.

- Construction Workers & First Line Supervisors (EPC contractor employees and subcontractors) are covered by the FPL-approved EPC contractor FFD Program (elements Subpart K).

- FPL employees and FPL subcontractor's construction management and oversight personnel are covered by the Turkey Point Units 3 & 4 Operations FFD Program and the EPC contractor's employees and subcontractors construction management and oversight personnel are covered by the FPL-approved EPC contractor FFD Program (elements Subpart A–H, N, and O).

- FPL security personnel are covered by the Turkey Point Units 3 & 4 Operations FFD Program and the EPC contractor's security personnel are covered by the FPL-approved EPC contractor FFD Program (elements Subpart A–H, N, and O). This coverage is applicable from the start of construction activities to the earlier of (1) the receipt of SNM in the form of fuel assemblies, (2) the establishment of a protected area, or (3) the 10 CFR 52.103(g) finding.

- FPL FFD Program personnel are covered by the Turkey Point Units 3 & 4 Operations FFD Program and the EPC contractor's FFD Program personnel are covered by the FPL-approved EPC contractor FFD Program (elements Subpart A, B, D–H, N, O, and C per licensee's discretion).

- FPL security personnel protecting fuel assemblies, or the established protected area, or the facility following the 10 CFR 52.103(g) finding are covered by the Turkey Point Units 3 & 4 Operations FFD Program (elements Subpart A–I, N, and O).

- Personnel required to physically report to the Technical Support Center (TSC) or Emergency Operations Facility (EOF) when that requirement is in effect are covered by the Turkey Point Units 3 & 4 FFD Program (elements Subpart A–I, N, and O, except for §§ 26.205–209).

STD SUP 13.7-1 The operations phase FFD program is consistent with the applicable subparts of 10 CFR Part 26 (elements Subpart A – I, N, and O, except for individuals listed in §26.4(b), who are not subject to §§ 26.205 – 209.

13.7.1 REFERENCES

201. Nuclear Energy Institute, *Fitness for Duty Program Guidance for New Nuclear Power Plant Construction Sites*, NEI 06-06, Rev. 5, NRC ADAMS Accession No. ML092430016, August 2009.

Add the following new appendix at the end of DCD Chapter 13.

PTN COL 13.1-1

APPENDIX 13AA CONSTRUCTION-RELATED ORGANIZATION

The information in this appendix is included for future designation as historical information. Paragraphs are numbered to be subsequent to Subsection 13.1.1.1.

13AA.1.1.1.1 Design and Construction Activities

The Westinghouse Electric Company (WEC) was selected to design, fabricate, deliver, and install the AP1000 advanced light water pressurized water reactors (PWR) and to provide technical direction for installation and startup of this equipment. DCD Subsection 1.4.1 provides detailed information regarding WEC past experience in designing, developing, and manufacturing nuclear power facilities. Operating experience from designing, constructing, and operating earlier WEC PWRs is applied in designing, constructing, and operating the AP1000 as described in numerous locations throughout the DCD (e.g., DCD Subsections 3.6.4.4, 3.9.4.2.1, 4.2.3.1.3).

A construction architect/engineer provides the construction of the plant and additional design engineering for selected site-specific portions of the plant. The architect/engineer is selected based on experience and proven technical capability in nuclear construction projects or projects of similar scope and complexity.

Other design and construction activities are generally contracted to qualified suppliers of such services. Implementing or delegating design and construction responsibilities is described in the subsections below. QA aspects of these activities are described in Chapter 17.

13AA.1.1.1.1.1 Principal Site-Related Engineering Work

The principal site engineering activities accomplished toward plant construction and operation are:

a. Meteorology

Information concerning local (site) meteorological parameters is developed and applied by plant and contract personnel to assess the impact of Units 6 & 7 on local meteorological conditions. An onsite meteorological measurements program is employed by unit personnel to produce data for the purpose of making

atmospheric dispersion estimates for postulated accidental and expected routine airborne releases of effluents. A maintenance program is established for surveillance, calibration, and repair of instruments. More information regarding the study and meteorological program is found in Section 2.3.

b. Geology

Information relating to site and regional geotechnical conditions is developed and evaluated by utility and contract personnel to determine if geologic conditions could present a challenge to plant safety. Items of interest include geologic structure, seismicity, geological history, and ground water conditions. During construction, foundations in the power block area are mapped or visually inspected and photographed. Section 2.5 provides details of these investigations.

c. Seismology

Information relating to seismological conditions is developed and evaluated by utility and contract personnel to determine if the site location and area surrounding the site are appropriate from a safety standpoint for constructing and operating a nuclear power plant. Information regarding tectonics, seismicity, correlation of seismicity with tectonic structure, characterization of seismic sources, and ground motion are assessed to estimate the potential for strong earthquake ground motions or surface deformation at the site. Section 2.5 provides details of these investigations.

d. Hydrology

Information relating to hydrological conditions at the plant site and the surrounding area is developed and evaluated by utility and contract personnel. The study includes hydrologic characteristics of streams, lakes, shore regions, the regional and local groundwater environments, and existing or proposed water control structures that could influence flood control and plant safety. Section 2.4 includes more detailed information regarding this subject.

e. Demography

Information relating to local and surrounding area population distribution is developed and evaluated by utility and contract personnel. The data is used to determine if requirements are met for establishment of exclusion area, low population zone, and population center distance. Section 2.1 includes more detailed information regarding population around the plant site.

f. Environmental Effects

Monitoring programs are developed to enable the collection of data necessary to determine possible impact on the environment as a result of construction, startup, and operational activities and to establish a baseline from which to evaluate future environmental monitoring.

13AA.1.1.1.1.2 Design of Plant and Ancillary Systems

Responsibility for design and construction of systems outside the power block such as circulating water, service water, switchyard, and secondary fire protection systems is delegated to qualified contractors.

13AA.1.1.1.1.3 Review and Approval of Plant Design Features

Design engineering review and approval are performed in accordance with the reactor technology vendor QA program and Section 17.1. The reactor technology vendor is responsible for design control of the power block. Verification is performed by competent individuals or groups other than those who performed the original design. Design issues arising during construction are addressed and implemented with notifying and communicating changes to the engineering director for review. As systems are tested and approved for turnover and operation, control of design is turned over to plant staff. The engineering director, along with functional managers and staff, assumes responsibility for reviewing and approving modifications, additions, or deletions in plant design features, as well as control of design documentation, in accordance with the operational QA program. Design control becomes the responsibility of the engineering director before loading fuel. During construction, startup, and operation, changes to human-system interfaces of control room design are approved using a human factors engineering evaluation addressed in Chapter 18. See organization charts, Figures 13.1-201, and 13AA-201 for reporting relationships.

13AA.1.1.1.1.4 Site Layout With Respect to Environmental Effects and Security Provisions

Site layout was considered when determining the expected environmental effects from construction.

The Physical Security Plan is designed with provisions that meet the applicable NRC regulations. Site layout was considered when developing the Security Plan.

13AA.1.1.1.1.5 Development of Safety Analysis Reports

Information regarding the development of the Final Safety Analysis Report is found in Chapter 1.

13AA.1.1.1.1.6 Review and Approval of Material and Component Specifications

Safety-related material and component specifications of structures, systems, and components designed by the reactor technology vendor are reviewed and approved in accordance with the reactor technology vendor QA program and Section 17.1. Review and approval of items not designed by the reactor vendor are controlled for review and approval by Section 17.5 and the QAPD.

13AA.1.1.1.1.7 Procurement of Materials and Equipment

Procurement of materials during the construction phase is the responsibility of the reactor technology vendor and constructor. The process is controlled by the construction QA programs of these organizations. Oversight of the inspection and receipt of materials process is the responsibility of the manager in charge of QA.

13AA.1.1.1.1.8 Management and Review of Construction Activities

Overall management and responsibility for construction activities is assigned to the executive vice president-engineering, construction and corporate services. The project director new nuclear projects is accountable to the vice president-new nuclear projects for construction activities. See Organization Chart Figure 13AA-201. Monitoring and review of construction activities by utility personnel is a continuous process at the plant site. Contractor performance is monitored to provide objective data to utility management to identify problems early and develop solutions. Monitoring of construction activities verifies that the contractors are in compliance with contractual obligations for quality, schedule, and cost. Monitoring and review of construction activities is divided functionally across the various disciplines of the utility construction staff (e.g., electrical, mechanical, instrumentation and controls [I&C]) and tracked by schedule based on system and major plant components/areas.

After each system is turned over to plant staff, the construction organization relinquishes responsibility for that system. At that time they are responsible for completion of construction activities as directed by plant staff and available to provide support for preoperational and startup testing as necessary.

To ensure equipment operability and reliability, plant maintenance programs such as preventive and corrective maintenance are developed and made effective during preoperation/startup phase with approved administrative procedures under the direction of the managers in charge of maintenance, engineering, and work control.

Periodic assessment involving both the construction and operations organizations continues to identify SSCs that could reasonably be expected to be impacted by scheduled construction activities. Appropriate administrative and managerial controls are then established as necessary. Specific hazards, impacted SSCs, and managerial and administrative controls are reviewed on a recurring basis and, if necessary, controls are revised/developed and implemented and maintained current as work progresses on site. For example, prior to construction activities that involve the use of large construction equipment such as cranes, managerial and administrative controls are in place to prevent adverse impacts on any operating unit(s) overhead power lines, switchyard, security boundary, etc., by providing the necessary restrictions on the use of large construction equipment.

13AA.1.1.1.2 Startup Activities

The Units 6 & 7 plant general manager reports to the site vice president. The plant general manager, with the aid of those managers who report directly to the plant general manager (see Figure 13AA-201), is responsible for the plant activities required to transition the unit from the construction phase to the operational phase. These activities include coordinating the turnover to the plant staff of systems from the construction and preoperational testing phase, establishing the plant work management system, implementation of the initial fuel load, the integrated startup testing program and the development and issuance of the associated fuel load and startup procedures.

13AA.1.1.1.2.1 Development of Human Factors Engineering Design Objectives and Design Phase Review of Proposed Control Room Layouts

Human factors engineering (HFE) design objectives are initially developed by the reactor technology vendor in accordance with Chapter 18 of the FSAR and the Design Control Document (DCD). As a collaborative team, personnel from the reactor technology vendor design staff and personnel, including licensed operators, engineers, and I&C technicians from owner and other organizations in the nuclear industry assess the design of the control room and human-machine

interfaces (HMIs) to attain safe and efficient plant operation. See Section 18.2 for additional details of HFE program management.

Modifications to the certified design of the control room or HMIs described in the DCD are reviewed in accordance with engineering and site support procedures, as required by Section 18.2, to evaluate the impact to plant safety. The engineering director–new nuclear projects is responsible for the HFE design process and for the design commitment to HFE during construction and throughout the life of the plant as noted in Subsection 13.1.1.2.1. The HFE program is established in accordance with the description and commitments in Chapter 18.

13AA.1.1.1.2.2 Preoperational and Startup Testing

Preoperational and startup testing is conducted by the plant test and operations (PT&O) organization. The PT&O organization, functions, and responsibilities are addressed in Section 14.2. Sufficient numbers of personnel are assigned to perform preoperational and startup testing to facilitate safe and efficient implementation of the testing program. Plant-specific training provides instruction on the administrative controls of the test program. To improve operational experience, operations and technical staff are used as support in conducting the test program and in reviewing test results.

13AA.1.1.1.2.3 Developing and Implementing Staff Recruiting and Training Programs

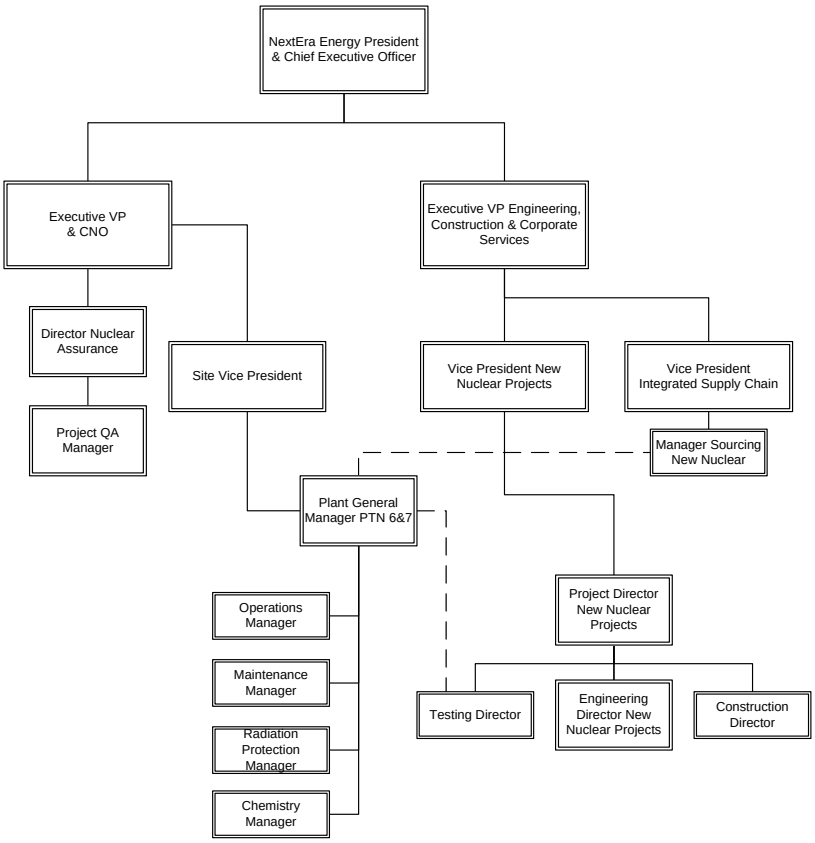
Staffing plans are developed based on operating plant experience, with input from the reactor technology vendor for safe plant operation as determined by HFE. See Section 18.6. These plans are developed under the direction and guidance of the vice president-new nuclear projects and the site vice president. Staffing plans are completed and manager level positions are filled before preoperational testing is started. Personnel selected to be licensed reactor operators and senior reactor operators, along with other staff necessary to support safe plant operation, are hired with sufficient time available to complete appropriate training programs and to become qualified, and licensed, if required, before fuel is loaded into the reactor vessel. See Figure 13AA-202 for an estimated timeline of hiring requirements for operator and technical staff relative to fuel load.

Because of the dynamic nature of the staffing plans and changes that occur over time, it is expected that specific numbers of personnel on site will change, however, Table 13.1-201 includes the initial estimated number of staff for selected positions and the estimated number of additional positions required for a second

unit. Recruiting personnel to fill positions is the shared responsibility of the manager in charge of human resources and the various heads of departments. The training program is described in Section 13.2.

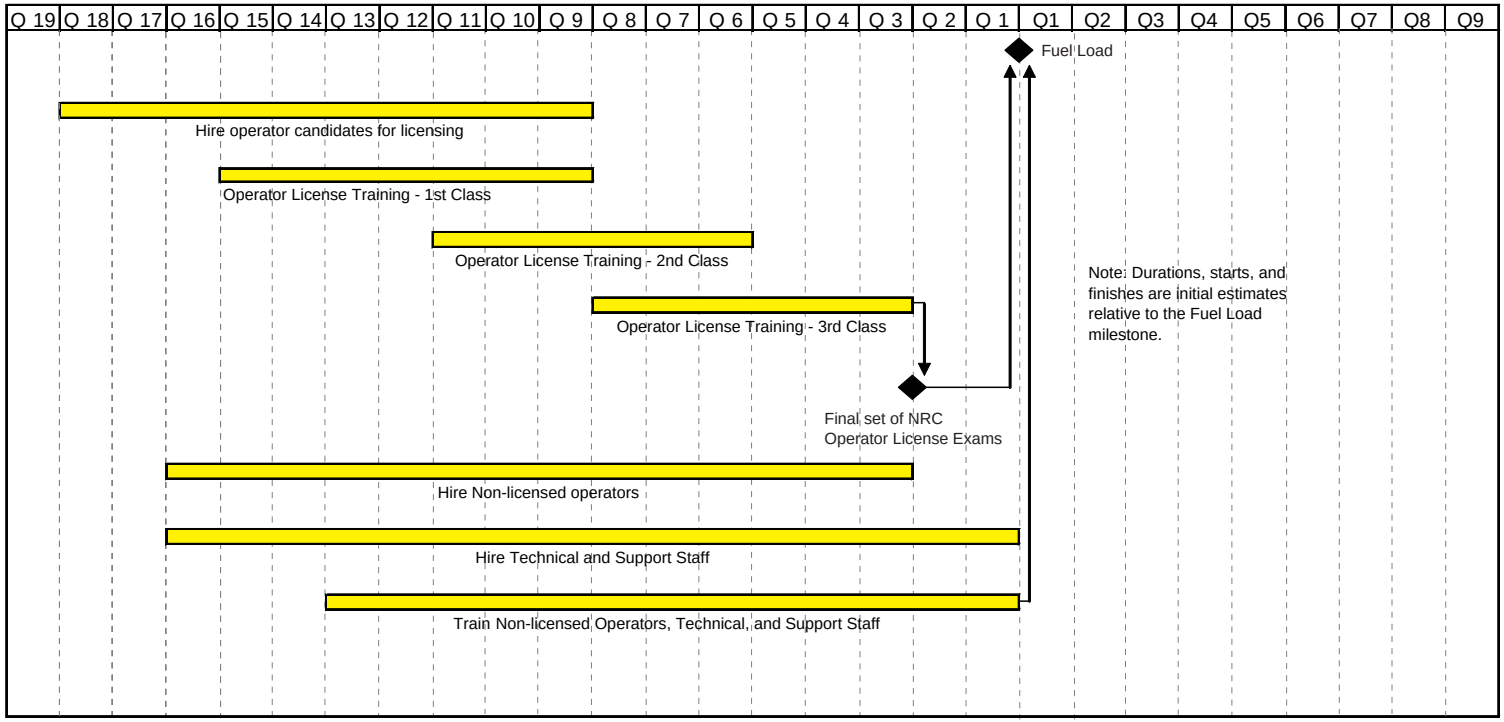
PTN COL 13.1-1

Figure 13AA-201 Construction Management Organization



PTN COL 13.1-1

Figure 13AA-202 Hiring Schedule for Plant Staff



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CHAPTER 14 INITIAL TEST PROGRAM

14.1 SPECIFIC INFORMATION TO BE INCLUDED IN PRELIMINARY/FINAL SAFETY ANALYSIS REPORTS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

14.2 SPECIFIC INFORMATION TO BE INCLUDED IN STANDARD SAFETY ANALYSIS REPORTS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

Add the following subsection at the end of DCD Subsection 14.2.1:

STD COL 14.4-3 FSAR Section 14.2 provides the requirements to be included in the Startup Administrative Manual (Procedures), as discussed in DCD Subsection 14.4.3. The information referenced in this section meets the Initial Test Program (ITP) criteria of NUREG-0800 and is formatted to follow Regulatory Guide 1.206, Part I, Section C.I.14.2.

The ITP is applied to structures, systems, and components that perform the functions described in the Regulatory Guide 1.68 evaluation in FSAR Section 1.9. The ITP is also applied to other structures, systems and components. The Startup Administrative Manual includes a list of the AP1000 structures, systems and components to which the ITP is applied.

Add the following Subsections after DCD Subsection 14.2.1.3

14.2.1.4 Testing of First of a Kind Design Features

STD COL 14.4-3 First of a kind (FOAK) testing may occur in any of the phases, depending on the nature of the testing and required sequencing of the tests. When testing FOAK design features, applicable operating experience from previous test performance of other AP1000 plants is reviewed, where available, and the ITP modified as needed based on those lessons learned.

14.2.1.5 Credit for Previously Performed Testing of First of a Kind Design Features

In some cases, FOAK testing is required only for the first of a new design or for the first few plants of a standard design. In such cases, credit may be taken for the previously performed tests. A discussion is included in the startup test reports of the results of those tests that are credited.

14.2.2 ORGANIZATION, STAFFING, AND RESPONSIBILITIES

Replace the existing information in DCD Subsection 14.2.2 with the following new paragraph and subsections.

STD COL 14.4-1 The AP1000 plant test and operations (PT&O) organization is described in Subsection 14.2.2.1. The organization for operating and maintaining the AP1000 plant is described in Section 13.1.

The PT&O organization structure (organizational chart) is included in the Startup Administrative Manual.

Table 13.4-201 provides milestones for initial test program implementation.

14.2.2.1 PT&O Organization

The Initial Test Program (ITP) is the responsibility of the PT&O Organization. The ITP includes three phases of testing:

- Construction and Installation Testing
- Preoperational Testing
- Startup Testing

PTN COL 14.4-1

14.2.2.1.1 Testing Director

The Testing Director manages the ITP. During construction and preoperational testing, the Testing Director reports directly to the Project Director New Nuclear Projects. Beginning at initial fuel load, the Testing Director functionally reports to the Plant General Manager for Units 6 & 7. The Testing Director is responsible for:

- Staffing the PT&O organization
- Developing, reviewing, and approving the administrative and technical procedures associated with the preoperational and startup phases
- Managing the ITP and personnel

- Implementing the ITP schedule
- Managing contracts associated with the ITP

14.2.2.1.2 PT&O Support Manager

The PT&O Support Manager reports directly to the Testing Director. The PT&O Support Manager plans and schedules procedure development to support startup. The PT&O Support Manager verifies that the test documents conform to the approved project procedures.

14.2.2.1.3 PT&O Engineers

The PT&O engineers report directly to the PT&O Support Manager. The PT&O engineers are responsible for developing preoperational and startup test procedures.

14.2.2.1.4 Startup Manager

The Startup Manager reports directly to the Testing Director and manages the preoperational and startup testing. The Startup Manager is responsible for:

- Participating in the Joint Test Working Group (JTWG) and ensuring that the JTWG reviews and approves administrative and test procedures. The JTWG structure and responsibilities are defined in Subsection 14.2.2.3.
- Preparing a detailed preoperational and startup testing schedule
- Coordinating construction turnover to the PT&O organization
- Informing the Testing Director when vendor support essential to preoperational and startup testing is required, and coordinating vendor participation
- Supervising and directing the startup engineers
- Involving operations personnel in testing activities by using operations personnel, to the extent practical, as test witnesses or test performers to provide the operations personnel with experience and knowledge
- Developing and implementing administrative controls to address system and equipment configuration control

- Maintaining the startup schedule
- Maintaining a daily startup log and issuing periodic progress reports that identify overall progress and potential challenges

14.2.2.1.5 Startup Engineers

The startup engineers report directly to the Startup Manager.

The startup engineers are responsible for:

- Complying with administrative controls
- Identifying any special or temporary equipment or services needed to support testing
- Coordinating testing with involved groups
- Performing preoperational and startup tests
- Reviewing and evaluating test results

STD COL 14.4-1

14.2.2.2 PT&O Organization Personnel Qualifications and Training

Procedures are prepared to confirm that test personnel have adequate training, qualification and certification. Records are kept for extent of experience, involvement in procedure and test development, training programs, and level of qualification. The training organization qualifies Test Personnel as applicable, in accordance with the requirements of the applicable Quality Assurance Program. Training is performed as agreed between Westinghouse and the Licensee. Westinghouse test personnel training is per certified design.

Acceptable qualifications of non-supervisory test engineers follow the guidance provided in Regulatory Guide 1.28 as discussed in Appendix 1AA, i.e., ASME NQA-1-1994, Appendix 2A-1, Nonmandatory Guidance on the Qualification of Inspection and Test Personnel.

The training program/procedures shall include:

- The education, training, experience, and qualification requirements of supervisory personnel, test personnel, and other major participating

organizations responsible for managing, developing, or conducting each test phase, or development of testing, operating, and emergency procedures.

- The establishment of a training program for each organizational unit, with regard to the scheduled preoperational and initial startup testing. This training program provides meaningful technical information beyond that obtained in the normal startup test program and provide supplemental operator training. This program also satisfied the criteria described in TMI Action Plan Item I.G.1 of NUREG-0660 and NUREG-0737.

The Startup Administrative Manual (Procedure) shall include:

- The implementation of measures to verify that personnel formulating and conducting test activities are not the same personnel who designed or are responsible for satisfactory performance of the system(s) or design feature(s) being tested. This provision does not preclude members of the design organization from participating in test activities. This description also includes considerations of staffing effects that could result from overlapping initial test programs at multi-unit sites.

14.2.2.3 Joint Test Working Group

The Joint Test Working Group (JTWG) consists of an organizational group of authorized representative personnel from the Plant's operations and support group functions, Westinghouse Electric Company (WEC), Architect Engineer and other test support groups as identified below.

The Licensee has the overall responsibility for conduct of the Startup Test Program. The Westinghouse Startup Manager may be assigned overall responsibility and authority for technical direction of the Startup Test Program and may act as the JTWG Chairman.

The JTWG Chairman reports to the Chairman of the Plant Owner's Operations Review Committee (PORC) or qualified designee for matters of Startup test authority and acceptance.

The JTWG provides the following administrative oversight activities associated with the Startup Test Program:

- Review, evaluate and approve Startup Test Program administrative and test procedures.

- Oversee the implementation of the Preoperational Test Program and the Startup Test Program, including planning, scheduling and performance of Preoperational and Startup testing.
- Review and evaluate Construction, Preoperational and Startup test results and test turnover packages.

PTN COL 14.4-1 At a minimum, the JTWG is composed of qualified representatives provided from the following organizations:

- Licensee's Operations Group
- Licensee's Maintenance Group
- Site Preoperational Test Group
- Site Startup Test Group
- Licensee's Engineering Group
- Licensee's Corrective Action Organization
- Westinghouse Site Engineering Group
- Licensee's Radiation Protection/Chemistry Group
- Licensee's Quality Assurance Group

STD COL 14.4-1 The following are additional generic details of the key responsibilities, authorities and interfaces of the Licensee Organizations delineated above:

- Operations Group

The Operations Group has the overall responsibility for Plant Operations, including administrative control and tag-outs subsequent to system turnover. Their primary interfaces are with the Licensee Engineering and Technical Support organizations as well as the Westinghouse Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group.

- Maintenance Group

The Maintenance Group has the overall responsibility for the Maintenance of Plant systems and components subsequent to System Turnover. They are key participants and maintainers of system maintenance control and tag-outs. Their primary interfaces are with the Licensee Operations Group and Technical Support organizations, as well as the Westinghouse Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group.

- Corrective Action Organization

The Corrective Action Organization may be an organization specific to itself or may be a part of the Performance Assessment organization, the Quality Organization or another organization. This organization, together with every other site organization, is responsible for the administration and management of the corrective action program, as well as the identification of conditions adverse to quality. This organization interfaces with site organizations and identifies and documents conditions which need to be documented in the corrective action program.

- Engineering Group

This group has the primary responsibility for site engineering and design oversight of the plant components and systems, as well as interfacing with the vendor engineering organization. This organization primarily interfaces with the Operations Group as well as the Westinghouse Site Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group. The responsibility for training the testing personnel in accordance with applicable Quality Assurance Program is delegated and implemented as agreed to by Westinghouse. Westinghouse test personnel training is per certified design.

PTN COL 14.4-1

- Radiation Protection/Chemistry Group

This Technical Support organization has the responsibility and authority to maintain Radiation Protection and system chemistry conditions at the plant, particularly after system turnover. This organization primarily interfaces with the Licensee Operations Group, as well as the Westinghouse Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group.

STD COL 14.4-1

- Quality Assurance Group

This group has the responsibility to verify that the applicable site Quality commitments are met within the scope of work performed at the site. This includes meeting the Criteria of 10 CFR 50 Appendix B. The primary interfaces for this group are the Licensee Operations Group and Technical Support organizations, including Quality Control and other quality organizations, as well as the Westinghouse Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group.

- Site Preoperational Test Group

This group has the primary responsibility for the development, maintenance and performance of the site preoperational procedures at the site. The primary interfaces for this group are the Licensee Operations Group and Technical Support organizations, as well as the Westinghouse Engineering Organization, Startup Testing Teams and the Construction Services Group. Additional specific information regarding this organization's responsibilities and interfaces is described in Subsection 14.2.2.5, below. Once preoperational testing is complete, this group turns systems over to the Startup Group.

- Site Startup Test Group

This group has the primary responsibility for the development, maintenance and performance of the site startup procedures at the site. The primary interfaces for this group are the Licensee's Operations Group and Technical Support organizations, as well as the Westinghouse Engineering Organization, Preoperational Testing Team and the Construction Services Group. Additional specific information regarding this organization's responsibilities and interfaces is described in Subsection 14.2.2.6, below. The Startup Test Group turns over systems to the licensee when testing is complete.

- Westinghouse Site Engineering Group

This group has the primary responsibility for the vendor interface between the site and the vendor's home offices, as well as the design authority for the primary vendor's components and systems. The various Westinghouse site leads for specific disciplines are a part of this organization. This organization primarily interfaces with Licensee Operations Group, as well as the Westinghouse Engineering Organization, Preoperational and Startup Testing Teams and Construction Services Group. The responsibility for training the testing personnel

in accordance with the applicable Quality Assurance Program is delegated and implemented as agreed to by Westinghouse and the Licensee. Westinghouse test personnel training is per certified design.

14.2.2.4 Site Construction Group (Architect Engineer)

The Site Construction Group consists of the following, as necessary to support the Site Startup Test Program:

- Construction Group

The Construction group has the primary responsibility for the construction and construction testing of the Balance of Plant (BOP) engineering systems and components. During Construction and Construction Testing, this group has authority over administrative control and tagouts of these systems. Their main interface is with the System Preoperational and Startup Testing Groups, as well as the Licensee Operations Group. The Construction Group is responsible for addressing open items in the system turnover punch lists to address turnover acceptability of the system.

- Construction Services Group

The Construction Services Group primarily supports the Construction Group with activities necessary to support construction of systems and testing of the BOP systems and components, including the construction of scaffolding, installation and removal of insulation, and similar activities. With agreement between the necessary parties, this group may also support the Westinghouse Site Engineering Group with similar activities on the primary side. The primary interfaces of this group are the Construction Group and the organizations of the JTWG.

- Construction Services Procurement Group

The Construction Services Procurement Group is responsible for the quality procurement of components and equipment necessary to support plant construction and testing. The primary interfaces of this group include the Construction Services Group and the Construction Services Quality Group.

- Construction Services Quality Group

The Construction Services Quality Group is responsible for the oversight of the Quality Program during Construction Activities, including those pertinent to 10

CFR 50 Appendix B and the disposition of Significant Construction Deficiencies, 10 CFR 50.55(e) reports as necessary. This group primarily interfaces with the Construction and Services groups as well as the Westinghouse Site Engineering group and the JTWG.

- Construction Services Training Group

This group is primarily responsible for the training and qualification of Site Construction Personnel in accordance with the applicable Quality Assurance Program. Their primary interface is with the qualified Construction personnel.

The Site Construction Group performs the following functions and scope of work, as necessary to support the Site Startup Test Program:

- Construction Installation and Testing, including management of construction testing documentation.
- Construction and Installation activities required to support Preoperational and Startup Test Programs.
- Vendor interface and procurement associated with supporting testing activities.
- Provide staffing as needed to support the testing activities.
- Turnover of Construction and Installation tested equipment, systems, and testing documentation to the Site Preoperational Test Group.

14.2.2.5 Site Preoperational Test Group

The Site Preoperational Test Group consists of the following, as necessary to support the Site Startup Test Program:

- Engineering Leads
- Preoperational Test Teams

The Site Preoperational Test Group performs the following functions and scope of work, as necessary to support the Site Startup Test Program:

- Coordinate tagging and maintenance prior to turnover to the Licensee to support system acceptance testing.

- Accept systems for turnover from the installation organization.
- Plan, scope and schedule plant systems for test to support the plant Preoperational Test Program.
- Manage and oversee the testing of plant systems to support the Plant Hot-Functional Test Program.
- Resolve open items and exceptions identified during implementation of the Preoperational Test Program.
- Accept and turn over Preoperational Test Packages to the Site Licensee.
- Support completion of Hot-Functional Test Program.
- Coordinate other support tasks required during Startup Testing activities with responsible groups (e.g., Licensee's Organization).

14.2.2.6 Site Startup Test Group

The Site Startup Test Group consists of the following, as necessary to support the Site Startup Test Program:

- Engineering Leads
- Startup Test Teams

The Site Startup Test Group performs the following functions and scope of work, as necessary to support the Site Startup Test Program:

- Coordinate tagging and maintenance as required to support system and equipment acceptance testing.
- Accept systems, structures and components from the Licensee for integrated testing.
- Plan, scope and schedule plant systems, structures and components for testing, to support Plant Startup.
- Manage and oversee the testing of plant systems, structures and components to support the Plant Power Ascension Test Program.

- Resolve open items and exceptions identified during implementation of the Startup Test Program.
- Accept and turn over Startup Test Packages to the Site Licensee.
- Coordinate other support tasks required during Startup Testing activities with responsible groups (e.g., Licensee's Organization).

14.2.3 TEST SPECIFICATIONS AND TEST PROCEDURES

STD COL 14.4-3

Add the following text at the end of DCD Subsection 14.2.3:

The Startup Administrative Manual shall include the following controls:

- Controls to provide test procedures that include appropriate prerequisites, objectives, safety precautions, initial test conditions, methods to direct and control test performance, and acceptance criteria by which the test is evaluated.
- Controls for the format of individual test procedures to provide consistency with the guidance contained in RG 1.68; or provide justifications for any exceptions.
- Controls to provide for participation of the principal design organizations in establishing test objectives, test acceptance criteria, and related performance requirements during the development of detailed test procedures. Each test procedure should include acceptance criteria that account for the uncertainties used in transient and accident analyses. The participating system designers should include the nuclear steam supply system vendor, architect-engineer, and other major contractors, subcontractors, and vendors, as applicable.
- Controls to provide for personnel with appropriate technical backgrounds and experience to develop and review test procedures. Persons filling designated management positions should perform final procedure review and approval.
- Controls to make the approved test procedures for satisfying FSAR testing commitments are made available to the NRC inspectors approximately 60 days prior to their intended use.

14.2.3.1 Conduct of Test Program

STD COL 14.4-3

Add the following text and Subsection at the end of DCD Subsection 14.2.3.1:

The Startup Administrative Manual (procedure) governs the initial testing and is issued no later than 60 days prior to the beginning of the pre-operational phase. Testing during all phases of the test program is conducted using approved test procedures.

14.2.3.1.1 Procedure Verification

Since procedures may be approved for implementation weeks or months in advance of the scheduled test date, a review of the approved test procedure is required before commencement of testing. The test engineer is responsible for verifying:

- Drawing and document revision numbers listed in the reference section of the test procedure agree with the latest revisions.
- The procedure text reflects any design and licensing (i.e., FSAR and Technical Specifications) changes made since the procedure was originally approved for implementation.
- Any new (since preparation of the procedure) Operating Experience lessons learned are incorporated into individual test procedures.

Procedures require signoff verification for prerequisites and instruction steps. This signoff includes identification of the person doing the signoff and the date and time of completion.

Test engineers maintain chronological logs of test status to facilitate turnover and aid in maintaining operational configuration control. These logs become part of the test documentation.

There is a documented turnover process to make known the test status and equipment configuration when personnel transfer responsibilities, such as during a shift change.

Test briefings are conducted for each test in accordance with administrative procedures. When a shift change occurs before test completion, another briefing occurs before resumption or continuation of the test.

Data collected is marked or identified with test, date, and person collecting data. This data becomes part of the test documentation.

The plant corrective action program is used to document deficiencies, discrepancies, exceptions, non-conformances and failures (collectively known as test exceptions) identified in the ITP. The corrective action documentation becomes part of the test documentation. WEC and/or other design organizations participate in the resolution of design-related problems that result in, or contribute to, a failure to meet test acceptance criteria.

The plant manager approves proceeding from one test phase to the next during the ITP. Approvals are documented in an overall ITP governance document.

Administrative procedures detail the test documentation review and approval. Review and approval of test documentation includes the test engineer, testing supervisor, Startup Group manager, WEC site representative or appropriate vendor, and JTWG. Final approval is by the plant manager.

Plant readiness reviews are conducted to assure that the plant staff and equipment are ready to proceed to the next test phase or plateau.

14.2.3.1.2 Work Control

STD SUP 14.2-5

The Startup Group is responsible for preparing work requests when assistance is required from the Construction organization. Work requests are issued in accordance with a site-specific procedure governing the work management process. The plant staff, upon identifying a need for Construction organization assistance, coordinates their requirements through the appropriate Startup Test Engineer.

Activities requiring Construction organization work efforts are performed under the plant tagging procedures. Tagging requests are governed by a site-specific procedure for equipment clearance. Tagging procedures shall be used for protection of personnel and equipment and for jurisdictional or custodial conditions that have been turned over in accordance with the turnover procedure.

The Startup Group is responsible for supervising minor repairs and modifications, changing equipment settings, and disconnecting and reconnecting electrical terminations as stipulated in a specific test procedure. Startup Test Engineers may perform independent verification of changes made in accordance with approved test procedures.

14.2.3.1.3 System Turnover

STD SUP 14.2-6

During the construction phase, systems, subsystems, and equipment are completed and turned over in an orderly and well-coordinated manner. Guidelines are established to define the boundary and interface between related system/subsystem and are used to generate boundary scope documents; for example, marked-up piping and instrument diagrams (P&IDs) and electrical schematic diagrams are provided for scheduling and subsequent development of component and system turnover packages. The system turnover process includes requirements for the following:

- Documenting inspections performed by the construction organization (e.g., highlighted drawings showing areas inspected).
- Documenting results of construction testing.
- Determining the construction-related inspections and tests that need to be completed before preoperational testing begins. Any open items are evaluated for acceptability of commencing preoperational testing.
- Developing and implementing plans for correcting adverse conditions and open items, and means for tracking such conditions and items.
- Verifying completeness of construction and documentation of incomplete items.

14.2.3.1.4 Conduct of Modifications During the Initial Test Program

STD SUP 14.2-7

Temporary alterations may be required to conduct certain tests. These alterations are documented in the test procedures. The test procedures contain restoration steps and retesting necessary to confirm satisfactory restoration to the required configuration. Modifications may be performed by the Construction organization or the plant staff processes prior to NRC issuance of the 10 CFR 52.103(g) finding. If

the modification invalidates a previously completed ITAAC, then that ITAAC is re-performed. Each modification is reviewed to determine the scope of post-modification testing that is to be performed. Testing is conducted and documented to maintain the validity of preoperational testing and ITAAC. Alterations made following NRC issuance of the 10 CFR 52.103(g) finding are in accordance with plant processes and meet license conditions. Modifications that require changes to ITAAC require NRC approval of the ITAAC change.

14.2.3.1.5 Conduct of Maintenance During the Initial Test Program

STD SUP 14.2-8

Corrective or preventive maintenance activities are reviewed to determine the scope of post-maintenance testing to be performed. Prior to NRC issuance of the 10 CFR 52.103(g) finding, post-maintenance testing is conducted and documented to maintain validity of associated preoperational testing and ITAAC remain valid. Maintenance performed following NRC issuance of the 10 CFR 52.103(g) finding is in accordance with plant staff processes and meets license conditions.

14.2.3.2 Review of Test Results

Add the following subsections at the end of DCD Subsection 14.2.3.2:

STD COL 14.4-4

14.2.3.2.1 Review and Approval Responsibilities

Upon completion of a test, the startup engineer is responsible for:

- Reviewing the test data.
- Evaluating the test results.
- Verifying that the acceptance criteria are met.
- Verifying that the test results that do not meet acceptance criteria are entered into the corrective action program.
- Verifying that the results of retesting do not invalidate ITAAC acceptance criteria.

Test results are reviewed and approved by the JTWG. Review and approval of test results are kept current such that succeeding tests are not dependent on systems or components that have not been adequately tested. Test exceptions which do not meet acceptance criteria are identified to the affected and responsible design organizations and entered into the corrective action program. Implementation of corrective actions and retests are performed as required.

PTN COL 14.4-4 Before initial fuel load, the results of the preoperational test phase are comprehensively reviewed by the PT&O organization and the JTWG to verify that the results indicate that the required plant structures, systems, and components are capable of supporting the initial fuel load and subsequent startup testing. The Project Director New Nuclear Projects approves fuel loading.

Each area of startup testing is reviewed and evaluated by the PT&O organization and the JTWG. The test results at each power ascension testing power plateau are reviewed and evaluated by the PT&O organization and the JTWG and approved by the Project Director New Nuclear Projects before proceeding to the next plateau. Startup test reports are prepared in accordance with position C.9 of Regulatory Guide 1.68, “Initial Test Programs for Water-Cooled Nuclear Power Plants.”

The reactor vendor is responsible for reviewing and approving the results of the tests of supplied equipment. Architect Engineer representatives review and approve the results of the tests of supplied equipment. Other vendors' representatives review and approve the results of the tests of supplied equipment. Final approval of individual test completion is by the Project Director New Nuclear Projects after approval by the Joint Test Working Group (JTWG).

14.2.3.2.2 Technical Evaluation

STD COL 14.4-4 Each completed test package is reviewed by technically qualified personnel to confirm satisfactory demonstration of plant, system or component performance and compliance with design and license criteria.

14.2.3.3 Test Records

Add the following subsection at the end of DCD Subsection 14.2.3.3:

14.2.3.3.1 Startup Test Reports

STD COL 14.4-4 Startup test reports are generated describing and summarizing the completion of tests performed during the ITP. A startup report is submitted at the earliest of:

1) 9 months following initial criticality,

2) 90 days after completion of the ITP, or

3) 90 days after start of commercial operations. If one report does not cover all three events, then supplemental reports are submitted every three months until all three events are completed. These reports:

- Address each ITP test described in the FSAR.
- Provide a general description of measured values of operating conditions or characteristics obtained from the ITP as compared to design or specification values.
- Describe any corrective actions that were required to achieve satisfactory operation.
- Include any other information required by license conditions.

14.2.5 UTILIZATION OF REACTOR OPERATING AND TESTING EXPERIENCE IN THE DEVELOPMENT OF TEST PROGRAM

Add the following Subsections after DCD Subsection 14.2.5:

Utilization of Operating Experience

STD SUP 14.2-4 Administrative procedures provide methodologies for evaluating and initiating action for operating experience information (OE). DCD Subsection 14.2.5 describes the general use of operating experience by WEC in the development of the test program.

14.2.5.1 Use of OE during Test Procedure Preparation

Administrative procedures require review of recent internal and external operating experience when preparing test procedures.

14.2.5.2 Sources and Types of Information Reviewed for ITP Development

Multiple sources of operating experience were reviewed to develop this description of the ITP administration program. These included INPO Reports, INPO Guidelines, INPO Significant Event Reports, INPO Significant Operating Experience Reports and NRC Regulatory Guide 1.68.

14.2.5.3 Conclusions from Review

The following conclusions are a result of the OE review conducted to develop this ITP administration program description:

- The test procedures should provide guidance as to the expected plant response and instructions concerning what conditions warrant aborting the test. Errors and problems with the procedures should be anticipated. A means for prompt but controlled approval of changes to test procedures is needed. Critical test procedures should provide specific criteria for test termination and specific steps to conduct termination is conducted in a safe and orderly manner. Providing procedural guidance for aborting the test could prevent delays in plant restoration. Conservative guidance for actions to be taken should be included in the procedures.

- Plant simulators may prove useful in preparing for special tests and verifying procedures.

- Appropriate component/system operability should be verified prior to critical tests.

- The need to perform physics tests that can produce severe power tilts should be evaluated, particularly if tests at other similar reactors have provided sufficient data to verify the adequacy of the nuclear physics analysis.

- Compensatory measures should be implemented in accordance with guidance for infrequently performed tests or evolutions, where appropriate.

14.2.5.4 Summary of Test Program Features Influenced by the Review

The conclusions from the preceding section were incorporated in Section 14.2.

14.2.5.5 Use of OE during Conduct of ITP

Administrative procedures require discussion of operating experience when performing pre-job briefs immediately prior to the conduct of a test.

14.2.6 USE OF PLANT OPERATING AND EMERGENCY PROCEDURES

STD COL 14.4-3 Add the following text and Subsection to the end of DCD Subsection 14.2.6:

These procedures are used extensively in the Human-Machine Interface Testing, which is integrated as a part of the Control Room Design finalization. Additionally, the AP1000 plant operating and emergency procedures are developed to support the following design finalization activities:

- Human Factors Engineering
- Operational Task Analysis
- Training Simulator Development
- Verification and Validation of the Procedures and the Training Material

The AP1000 emergency, abnormal and some normal operating procedures, along with some Alarm Response Procedures and surveillance procedures, are exercised and verified in the processes delineated above and in the Control Room design finalization process.

In addition, the AP1000 Preoperational Testing and Startup Test procedures are verified and validated during the design finalization process, which helps prevent human factors issues with the development of these procedures. In addition, the plant operators use the Normal Operating Procedures while preoperational and startup tests are performed, which adds to their validity and the plant operators training.

14.2.6.1 Operator Training and Participation during Certain Initial Tests (TMI Action Plan Item I.G.1, NUREG-0737)

The objective of operator participation is to increase the capability of shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted.

Operators are trained on the specifics of the ITP schedule, administrative requirements and tests. Specific Just In Time training is conducted for selected startup tests.

The ITP may result in the discovery of an acceptable plant or system response that differs from the expected response. Test results are reviewed to identify these differences and the training for operators is changed to reflect them. Training is conducted as soon as is practicable in accordance with training procedures.

14.2.8 TEST PROGRAM SCHEDULE

Add the following text and subsection at the end of DCD Subsection 14.2.8:

STD SUP 14.2-1 A site-specific initial test program schedule will be provided to the NRC after issuance of the COL. This schedule will address each major phase of the test program (including tests that are required to be completed before fuel load), as well as the organizational impact of any overlap of first unit initial testing with initial testing of the second unit.

The sequential schedule for individual startup tests should establish that testing is completed in accordance with plant technical specification requirements for structures, systems and components (SSC) operability before changing plant modes. Additionally, the schedule establishes that the safety of the plant is not dependent on the performance of untested SSCs. Guidance provided in Regulatory Guide 1.68 is used for development of the schedule.

The Startup Administrative Manual shall include the following controls:

- Test Procedure Development Schedule:
  - Controls to establish a schedule for the development of detailed testing, plant operating, and emergency procedures. These

procedures, to the extent practical, are trial-tested and corrected during the initial test program prior to fuel loading in order to establish their adequacy.

— Controls to confirm that approved test procedures are in a form suitable for review by NRC inspectors at least 60 days prior to their intended use, or at least 60 days prior to fuel loading for fuel loading and startup test procedures.

— Controls to provide timely notification to the NRC of changes in approved test procedures previously available for NRC review.

- Initial Test Program Schedule:

  — Controls to establish a schedule to conduct the major phases of the initial test program, relative to the expected fuel loading date. This is covered in License Conditions in Part 10 of the COL Application.

  — Controls to allow at least 9 months for conducting preoperational testing.

  — Controls to allow at least 3 months for conducting startup testing, including fuel loading, low-power tests, and power-ascension tests.

  — Controls to overlap test program schedules (for multi-unit sites) such that they do not result in significant divisions of responsibilities or dilutions of the staff provided to implement the test program.

  — Controls to sequence the schedule for individual startup tests, insofar as is practicable, such that testing is completed prior to exceeding 25 percent power for the plant SSCs that are relied upon to prevent, limit, or mitigate the consequences of postulated accidents. The schedule should establish that, insofar as is practicable, testing is accomplished as early in the test program as is feasible and that the safety of the plant is not dependent on the performance of untested SSCs.

The milestone schedule for developing plant operating procedures is presented in Table 13.4-201. The operating and emergency procedures are available prior to start of licensed operator training and, therefore, are available for use during the ITP. Required or desired procedure changes may be identified during their use.

Administrative procedures describe the process for revising plant operating procedures.

14.2.9 PREOPERATIONAL TEST DESCRIPTIONS

Add the following subsection at the beginning of DCD Subsection 14.2.9

STD SUP 14.2-2 During preoperational testing, it may be necessary to return system control to Construction organization to repair or modify the system or to correct new problems. Administrative procedures include direction for:

- Means of releasing control of systems and or components to construction.
- Methods used for documenting actual work performed and determining impact on testing.
- Identification of required testing to restore the system to operability/ functionality/availability status, and to identify tests to be re-performed based on the impact of the work performed.
- Authorizing and tracking operability and unavailability determinations.
- Verifying retests stay in compliance with ITAAC.

14.2.9.1.6 Main Control Room Emergency Habitability System Testing

General Test Acceptance Criteria and Methods

Revise paragraph (f) of DCD Subsection 14.2.9.1.6, General Test Acceptance Criteria and Methods section, to read as follows:

PTN DEP 6.4-2

f. The ability to maintain the main control room environment within specified limits for 72 hours (Reference DCD Subsection 6.4.3.2) is verified with a test simulating a loss of the nuclear island nonradioactive ventilation system. This testing demonstrates the control room heatup from 0 to 6 hours with the actual heat loads from the battery powered equipment and personnel specified for this time period (for the MCR (room 12401), there is automatic de-energization of specific non-safety MCR heat loads). The control room temperature versus time versus heat load data are used to

verify the analysis basis used to assure that the control room conditions remain within specified limits for the 72 hour time period. Periodic grab samples will be taken of the control room air environment to support analyses to confirm that specified limits would not be exceeded for 72 hours.

14.2.9.2.22 Pressurizer Surge Line Testing (First Plant Only)

STD COL 3.9-5

Purpose

The purpose of the pressurizer surge line testing is: a) to obtain data to verify the proper operation of temperature sensors installed on the pressurizer surge line and pressurizer spray line, and b) to obtain Reactor Coolant System piping displacement measurements for baseline data, as described in DCD Subsections 3.9.3, 14.2.5, and 14.2.9.1.7 item (d).

Prerequisites

The construction tests for the individual components associated with the Reactor Coolant System have been completed. The testing and calibration of the required test instrumentation has been completed. The temporary sensors and instrumentation lead wires required for monitoring thermal stratification, cycling, and striping have been installed. The calibration of the transducers and the operability of the data acquisition equipment have been verified. Prior to testing of the piping system, a pretest walk-down shall be performed to verify that the anticipated piping movement is not obstructed by objects not designed to restrain the motion of the system (including instrumentation and branch lines). The system walk-down shall also verify that supports are set in accordance with the design.

General Test Methods and Acceptance Criteria

The performance of the Reactor Coolant System is observed and recorded during a series of individual tests that characterize the various modes of system operation. This testing verifies that the temperature sensors operate as described in DCD Subsection 3.9.3 and in appropriate design specifications.

a. Verify the proper operation of temperature sensors installed on the pressurizer surge line and pressurizer spray line.

b. Record sensor data at specified intervals throughout hot functional testing of the RCS system, including during the drawing and collapsing of the bubble in the pressurizer.

c. Retain the following plant parameters time history for the same data recording period:

- Hot leg temperature
- Reactor Coolant System pressure
- Reactor coolant pump status
- Pressurizer level
- Pressurizer temperature (liquid and steam)
- Pressurizer spray temperature
- Pressurizer spray and auxiliary spray flow
- Normal residual heat removal system flow rate
- Passive core cooling system – passive residual heat removal flow rate

d. Monitor pressurizer surge line and pressurizer spray line for valve leakage.

e. Remove the transducers and associated hardware after the completion of testing.

f. Proper operation of the temperature sensors in the pressurizer surge and spray lines is verified.

14.2.9.4.15 Seismic Monitoring System Testing

Add the following text at the beginning of DCD Subsection 14.2.9.4.15:

STD COL 14.4-5 The seismic monitoring system testing described in this section of the DCD also applies to site-specific seismic sensors.

Add the following subsections after DCD Subsection 14.2.9.4.21:

STD COL 14.4-5

14.2.9.4.22 Storm Drains

Purpose

Storm drain system testing verifies that the drains prevent plant flooding by diverting storm water away from the plant, as described in Section 2.4.

Prerequisites

Construction of the storm drain system is completed, and the system is operational.

General Test Methods and Acceptance Criteria

The storm drain system is visually inspected to verify the flow path is unobstructed. The system is observed under simulated or actual precipitation events to verify that the runoff from roof drains and the plant site and adjacent areas does not result in unacceptable soil erosion adjacent to, or flooding of, Seismic Category I structures.

14.2.9.4.23 Off-Site AC Power Systems

Purpose

Off-site alternating current (ac) power system testing demonstrates the energization and proper operation of the as-installed switchyard components, as described in Section 8.2.

Prerequisites

Construction testing of plant off-site ac power systems, supporting systems, and components is completed. The components are operational and the switchyard equipment is ready to be energized. The required test instrumentation is properly calibrated and operational. The off-site grid connection is complete and available.

General Test Methods and Acceptance Criteria

The plant off-site ac power system components undergo a series of individual component and integrated system tests to verify that the off-site ac power system

performs in accordance with the associated component design specifications. The individual component and integrated tests include:

a. Availability of ac and direct current (dc) power to the switchyard equipment is verified.

b. Operation of high voltage (HV) circuit breakers is verified.

c. Operation of HV disconnect switches and ground switches is verified.

d. Operation of substation transformers is verified.

e. Operation of current transformers, voltage transformers, and protective relays is verified.

f. Operation of switchyard equipment controls, metering, interlocks, and alarms that affect plant off-site ac power system performance is verified.

g. Design limits of switchyard voltages and stability are verified.

h. Under simulated fault conditions, proper function of alarms and protective relaying circuits is verified.

i. Operation of instrumentation and control alarms used to monitor switchyard equipment status.

j. Proper operation and load carrying capability of breakers, switchgear, transformers, and cables, and verification of these items by a non-testing means such as a QC nameplate check of as built equipment where testing would not be practical or feasible.

k. Verification of proper operation of the automatic transfer capability of the preferred power supply to the maintenance power supply through the reserve auxiliary transformer.

l. Switchyard interface agreement and protocols are verified.

The test results confirm that the off-site ac power systems meet the technical and operational requirements described in Section 8.2.

14.2.9.4.24 Raw Water System

Purpose

Raw water system testing verifies that the as-installed components supply raw water to the circulating water cooling tower basin, service water system cooling tower basin, fire protection water storage tanks, and other systems, as described in Subsection 9.2.11.

Prerequisites

Construction testing of the raw water system is completed. The components are operational and the storage tanks and cooling tower basins are able to accept water. Required support systems, electrical power supplies, and control circuits are operational.

General Test Methods and Acceptance Criteria

The raw water system component and integrated system performance is observed to verify that the system functions, as described in Subsection 9.2.11 and in appropriate design specifications. The individual component and integrated system tests include:

PTN COL 14.4-5

a. Operation of the system pumps and valves is verified.

b. Operation of the system instrumentation, controls, actuation signals, alarms, and interlocks is verified.

STD COL 14.4-5

14.2.9.4.25 Sanitary Drainage System

Purpose

Sanitary drainage system testing verifies that the as-installed components properly collect and discharge sanitary waste, as described in DCD Subsection 9.2.6.

Prerequisites

Construction testing of the sanitary drainage system is completed. Required support systems, electrical power supplies, and control circuits are operational.

General Test Methods and Acceptance Criteria

The sanitary drainage system component and integrated system performance is observed to verify that the system functions, as described in Subsection 9.2.6.2.1 and in appropriate design specifications. The individual component and integrated system tests include:

a. Operation of lift stations and valves is verified.

b. Operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

14.2.9.4.26 Fire Brigade Support Equipment

Purpose

Fire brigade support equipment testing verifies that the equipment operates and is available when needed to perform the fire brigade functions, as described in Section 9.5.

Prerequisites

Equipment is ready and available for testing.

General Test Methods and Acceptance Criteria

The fire brigade support equipment undergoes a series of inspections to verify availability and operability. Equipment is available for selection and use, based on the hazard. Fire brigade support equipment tests include:

a. Location of portable extinguishers is verified; portable extinguishers are verified fully charged.

b. Operation of portable ventilation equipment is verified.

c. Operation of portable communication equipment is verified.

d. Operation of portable lighting is verified.

e. Operation of self-contained breathing apparatus and face masks is verified.

f. Operation of keys to open locked fire area doors is verified.

g. Turnout gear functionality and availability is verified.

h. Compatibility of threads for hydrants, hose couplings, and standpipe risers with the local fire department equipment is verified, or alternatively, an adequate supply of readily available hose thread adaptors is verified.

14.2.9.4.27 Portable Personnel Monitors and Radiation Survey Instruments

Purpose

Portable personnel monitors and radiation survey instruments testing verifies that the devices operate in accordance with their intended function in support of the radiation protection program, as described in Chapter 12.

Prerequisites

Portable personnel monitors, radiation survey instruments, and appropriate certified test sources are on site.

General Test Method and Acceptance Criteria

The portable personnel monitors and radiation survey instruments are source checked, tested, maintained, and calibrated in accordance with the manufacturers' recommendations. The portable monitors and instruments tests include:

a. Proper function of the monitors and instruments to respond to radiation is verified, as required.

b. Proper operation of instrumentation controls, battery, and alarms, if applicable.

PTN SUP 14.2-1 14.2.9.4.28 Deep Well Injection System

Purpose

Deep well injection system testing verifies that the as-installed components properly perform their specific system function, described in Subsection 9.2.12, of injecting effluent from the cooling tower blowdown, radioactive waste system, and wastewater system.

Prerequisites

Construction of each deep injection well is complete and the injection well components have been successfully tested. Required support systems, electrical power supplies, and control circuits are operational.

General Test Methods and Acceptance Criteria

The deep well injection system component and system performance is observed to verify that the system functions, as described in Subsection 9.2.12 and in appropriate design specifications. The individual component and integrated system tests include:

PTN COL 14.4-5

a. Operation of the valves is verified.

b. Operation of the system instrumentation, controls, actuation signals, alarms, and interlocks is verified.

Subsection 14.2.9.4.28 includes provisions for the initial testing of system components, including actuation signals and interlocks. The examples provided are intended to be inclusive of potential system components but do not represent system design finalization. The initial test program description will be revised as required to reflect final system design. Figure 9.2-203 does not include any instrumentation, control, actuation signal, alarms, or interlocks.

14.2.10 STARTUP TEST PROCEDURES

Add the following at the beginning of DCD Subsection 14.2.10:

STD SUP 14.2-3

The startup testing program is based on increasing power in discrete steps. Major testing is performed at discrete power levels as described in DCD Subsection 14.2.7. The first tests during Power Ascension Testing that verify movements and expansion of equipment are in accordance with design, and are conducted at a power level as low as practical (approximately 5 percent).

The governing Power Ascension Test Plan requires the following operations to be performed at appropriate steps in the power-ascension test phase:

- Conduct any tests that are scheduled at the test condition or power plateau.
- Confirm core performance parameters (core power distribution) are within expectations.
- Determine reactor power by heat balance, calibrate nuclear instruments accordingly, and confirm the existence of adequate instrumentation overlap between the startup range and power range detectors.
- Reset high-flux trips just prior to ascending to the next level to a value no greater than 20 percent beyond the power of the next level unless Technical Specification limits are more restrictive.
- Perform general surveys of plant systems and equipment to confirm that they are operating within expected values.
- Check for unexpected radioactivity in process systems and effluents.
- Perform reactor coolant leak checks.
- Review the completed testing program at each plateau; perform preliminary evaluations, including extrapolation core performance parameters for the next power level; and obtain the required management approvals before ascending to the next power level or test condition.

Upon completion of a given test, a preliminary evaluation is performed that confirms acceptability for continued testing. Smaller transient changes are performed initially, gradually increasing to larger transient changes. Test results at lower powers are extrapolated to higher power levels to determine acceptability of performing the test at higher powers. This extrapolation is included in the analysis section of the lower power procedure.

Surveillance test procedures may be used to document portions of tests, and ITP tests or portions of tests may be used to satisfy Technical Specifications surveillance requirements in accordance with administrative procedures. At Startup Test Program completion, a plant capacity warranty test is performed to satisfy the contract warranty and to confirm safe and stable plant operation.

Add the following subsection after DCD Subsection 14.2.10.4.28:

STD COL 14.4-5

14.2.10.4.29 Cooling Tower(s)

Objectives

- Verify proper cooling tower(s) function. Provide thermal acceptance testing of the cooling tower's heat removal capabilities.

Prerequisites

- The cooling tower(s) is structurally complete and in good operating condition.
- Circulating water system testing is complete.
- Required support systems, electrical power supplies, and control circuits are operational.

Test Method

Thermal performance of the cooling towers is tested and verified using established industry test standards.

Performance Criteria

The cooling tower(s) perform as described in Subsection 10.4.5 and in appropriate design specifications.

14.3 CERTIFIED DESIGN MATERIAL

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

Add the following subsections after DCD Subsection 14.3.2.2.

STD SUP 14.3-1

14.3.2.3 Site-Specific ITAAC (SS-ITAAC)

A table of inspections, tests, analyses, and acceptance criteria (ITAAC) entries is provided for each site-specific system described in this FSAR that meets the selection criteria, and that is not included in the certified design. The intent of these ITAAC is to define activities that are undertaken to verify the as-built system conforms with the design features and characteristics defined in the system design description. ITAAC are provided in tables with the following three-column format:

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria

Each design commitment in the left-hand column of the ITAAC tables has associated inspections, tests, or analyses (ITA) requirements specified in the middle column. The acceptance criteria for the ITA are defined in the right-hand column.

SS-ITAAC do not address ancillary buildings and structures on the site, such as administrative buildings, parking lots, warehouses, training facilities, etc.

Selection Criteria — The following are considered when determining what information is included in the SS-ITAAC:

- In determining those structures, systems, or components for which ITAAC must be prepared, the following questions are considered for each structure, system, or component:
  - Are any features or functions classified as Class A, B, or C?
  - Are any defense-in-depth features or functions provided?
  - For nonsafety-related systems, are any features or functions credited for mitigation of design basis events?

— For nonsafety-related systems, are there any features or functions that have been identified in DCD Section 16.3 as candidates for additional regulatory oversight?

If the answer to any of the above questions is yes, then ITAAC are prepared.

- The scope and content of the ITAAC correspond to the scope and content of the site-specific system design description.
- One inspection, test, or analysis may verify one or more provisions in the system design description. An ITAAC that specifies a system functional test or an inspection may verify a number of provisions in the system design description. There is not necessarily a one-to-one correspondence between the ITAAC and the system design descriptions.
- As required by 10 CFR 52.103, the inspections, tests, and analyses are completed (and the acceptance criteria satisfied) prior to initial fuel loading.
- The ITAAC verify the as-built configuration and performance characteristics of structures, systems, and components as identified in the system design descriptions.

Selection Methodology — Using the selection criteria, ITAAC table entries are developed for each selected system. This is achieved by evaluating the design features and performance characteristics defined in the system design descriptions and preparing an ITAAC table entry for each design description criterion that satisfies the selection criteria. A close correlation exists between the left-hand column of the ITAAC and the corresponding design description entries.

The ITAAC table is completed by selecting the method to be used for verification (either a test, an inspection, or an analysis) and the acceptance criteria for the as-built feature.

The approach used to perform the tests, inspections, or analyses is similar to that described in DCD Subsection 14.3.2.2.

14.3.2.3.1 Emergency Planning ITAAC (EP-ITAAC)

PTN SUP 14.3-1 EP-ITAAC have been developed to address implementation of elements of the Emergency Plan. Site-specific EP-ITAAC are based on the generic ITAAC provided in Appendix C.II.1-B of Regulatory Guide 1.206. These ITAAC have

been tailored to the specific reactor design and emergency planning program requirements.

14.3.2.3.2 Physical Security ITAAC (PS-ITAAC)

STD COL 13.6-1 Generic PS-ITAAC have been developed in a coordinated effort between the NRC and the Nuclear Energy Institute (NEI). These generic ITAAC have been tailored to the AP1000 design and site-specific security requirements.

14.3.2.3.3 Other Site-Specific Systems

STD SUP 14.3-1 One additional site-specific system has been determined to meet the ITAAC selection criteria, and ITAAC have been included for the Transmission Switchyard and Offsite Power System (ZBS) as indicated in Table 14.3-201. Systems not meeting the selection criteria are subject to the normal functional testing to verify that newly designed and installed systems, structures, or components perform as designed.

PTN SUP 14.3-2 A summary of the AP1000 structures, systems, or components considered for selection is given in Table 14.3-201. This table supplements DCD Table 14.3-1.

14.3.3 CDM SECTION 3.0, NON-SYSTEM BASED DESIGN DESCRIPTIONS AND ITAAC

Add the following new subsections after the first paragraph in DCD Subsection 14.3.3.

14.3.3.1 Subbasemat Concrete ITAAC

PTN SUP 14.3-3 Subbasemat concrete ITAAC will be developed to address verification that the subbasemat concrete has a compressive strength of 250–2000 psi, corresponding to a shear wave velocity in the range of 3500–6500 feet per second.

14.3.3.2 Pipe Rupture Hazard Analysis ITAAC

STD COL 3.6-1 A pipe rupture hazard analysis is part of the piping design. The analyses will document that structures, systems, and components (SSCs) which are required to be functional during and following a design basis event have adequate high-energy and moderate-energy pipe break mitigation features. The locations of postulated ruptures and essential targets will be established and required pipe whip restraint and jet shield designs will be included. The as-designed pipe rupture hazards analysis will be based on the as-designed piping analysis and will be in accordance with the criteria outlined in DCD Subsections 3.6.1.3.2 and 3.6.2.5. The evaluation will address environmental and flooding effects of cracks in high and moderate energy piping. The report of the pipe rupture hazard analysis shall conclude that, for each postulated piping failure, the systems, structures, and components that are required to be functional during and following a design basis event are protected.

The as-built reconciliation of the pipe rupture hazards evaluation whip restraint and jet shield design in accordance with the criteria outlined in DCD Subsections 3.6.1.3.2 and 3.6.2.5 are covered in as-built ITAAC identified in DCD Tier 1 to demonstrate that the as-built pipe rupture hazards mitigation features reflect the design, as reconciled. The reconciliation report will be made available for NRC inspection or audit when it has been completed.

The as-designed pipe rupture hazard analysis completed for the first standard AP1000 plant will be available to subsequent standard AP1000 plants under the "one issue, one review, one position" approach for closure.

14.3.3.3 Piping Design ITAAC

STD COL 3.9-7 The piping design ITAAC consists of the piping analysis for safety-related ASME Code piping. The piping design is completed on a package-by-package basis for applicable systems. In order to support closure of the piping design ITAAC, information consisting of the as-designed piping analysis for piping lines chosen to demonstrate all aspects of the piping design will be made available for NRC review, inspection, and/or audit. This information will consist of a design report referencing the as-designed piping calculation packages, including ASME Section III piping analysis, support evaluations and piping component fatigue analysis for Class I piping. The piping packages to be analyzed are identified in the DCD.

The ASME Code prescribes certain procedures and requirements that are to be followed for completing the piping design. The piping design ITAAC includes a verification of the ASME Code design report to ensure that the appropriate code design requirements for each system's safety class have been implemented.

A reconciliation of the applicable safety-related as-built piping systems is covered in as-built ITAAC identified in DCD Tier 1 to demonstrate that the as-built piping reflects the design, as reconciled. The reconciliation report will be made available for NRC inspection or audit when it has been completed.

The piping design completed for the first standard AP1000 plant will be available to subsequent standard AP1000 plants under the “one issue, one review, one position” approach for closure.

14.3.3.4 Waterproof Membrane ITAAC

PTN COL 2.5-17 The design of the waterproof membrane to be placed between the mudmats beneath the nuclear island basemat is described in DCD Subsection 3.4.1.1.1.1. Waterproof Membrane ITAAC have been developed to address verification that the mudmat-waterproofing-mudmat interface beneath the nuclear island basemat has a minimum coefficient of friction to resist sliding of 0.55.

14.3.3.5 Concrete Fill ITAAC

The ITAAC set of actions and criteria established for this foundation construction (concrete fill) activity are necessary and sufficient to provide reasonable assurance that, when met, the stability of Category I structure foundations is in conformance with the combined license. Subsection 2.5.4.5 discusses, in part, the excavations, backfill (including cementitious construction material) and earthwork analyses for Seismic Category I structures. The objective of this concrete fill ITAAC is to ensure reliable performance of the foundation bearing material over the life of the plant. Specifically, successful concrete fill ITAAC execution ensures that the first lift of concrete fill material is resistant to sulfate attack. By verifying water-cementitious material ratio and cement type, this ITAAC provides a method to confirm that sulfate-resistant properties of the fill material are achieved.

Successful concrete fill ITAAC execution also ensures that the static and dynamic properties of the material are the same as, or better than the design parameters.

In general, by testing the mean 28-day compressive strength of cementitious construction material, this ITAAC provides a method to confirm that the properties (static and dynamic) of said material are met prior to the construction of the Seismic Category I structure.

14.3.3.6 ITAAC for Category I Structure Foundation Grouting

The ITAAC set of actions and criteria established for this foundation construction (grouting) activity are necessary and sufficient to provide reasonable assurance that, when met, the stability of Category I structure foundations is in conformance with the combined license. This ITAAC ensures that the zone between El. –35 feet and El. –60 feet within the diaphragm walls (the Grouted Zone) is grouted according to the grout closure criteria that are developed as part of the grout test program. Specifically, successful grouting ITAAC execution results in any remaining voids in the Grouted Zone being structurally insignificant. The void size defined as structurally insignificant is determined in the grout test program. In addition, for the zone between El. –60 feet and –110 feet within the diaphragm walls (the Extended Grouted Zone), grouting is performed in every primary grout borehole. Primary grout boreholes are spaced less than or equal to 20 feet on center. Specifically, successful grouting ITAAC execution results in any remaining voids in the Extended Grouted Zone having a maximum equivalent spherical diameter of equal to or less than 20 feet. By verifying that the grout closure criteria of each zone are met and the as-built locations of the grout boreholes, this ITAAC provides a method to confirm that any remaining voids in the Grouted Zone are structurally insignificant and that the maximum equivalent spherical diameter of remaining voids in the Extended Grouted Zone is equal to or less than 20 feet.

PTN DEP 3.2-1

TABLE 14.3-2R (SHEET 1 OF 4)
DESIGN BASIS ACCIDENT ANALYSIS

DCD Reference		Design Feature	Value
Subsection	6.3.6.1.3	The bottom of the in-containment refueling water storage tank is located above the direct vessel injection nozzle centerline (ft).	≥ 3.4
Subsection	6.3.6.1.3	The pH baskets are located below plant elevation 107' 2".	
Figure	6.3-1	The passive core cooling system has two direct vessel injection lines.	
Table	6.3-2	The passive core cooling system has two core makeup tanks, each with a minimum required volume (ft^3).	2500
Table	6.3-2	The passive core cooling system has two accumulators, each with a minimum required volume (ft^3).	2000
Table	6.3-2	The passive core cooling system has an in-containment refueling water storage tank with a minimum required water volume (ft^3).	73,900
Subsection	6.3.2.2.3	The containment floodup volume for a LOCA in PXS room B has a maximum volume (ft^3) (excluding the IRWST) below a containment elevation of 108 feet.	73,500
Table	6.3-2	Each sparger has a minimum discharge flow area (in^2).	≥ 274
Table	6.3-2	The passive core cooling system has two pH adjustment baskets each with a minimum required volume (ft^3).	280
Subsection	14.2.9.1.3f	The passive residual heat removal heat exchanger minimum natural circulation heat transfer rate (Btu/hr) - With 520°F hot leg and 80°F IRWST - With 420°F hot leg and 80°F IRWST	 ≥ 1.78 E+08 ≥ 1.11 E+08
Subsection	6.3.6.1.3	The centerline of the HX's upper channel head is located above the HL centerline (ft).	≥ 26.3
Figure	6.3-1	The CMT level sensors (PXS-11A/B/C/D, -12A/B/C/D, -13A/B/C/D, and -14A/B/C/D) upper level tap centerlines are located below the centerline of the upper level tap connection to the CMTs (in).	1" ± 1"
Figure	6.3-1	The CMT inlet lines (cold leg to high point) have no downward sloping sections.	
Figure	6.3-1	The maximum elevation of the CMT injection lines between the connection to the CMT and the reactor vessel is the connection to the CMTs.	
Figure	6.3-1	The PRHR inlet line (hot leg to high point) has no downward sloping sections.	

PTN DEP 3.2-1

TABLE 14.3-2R (SHEET 2 OF 4)
DESIGN BASIS ACCIDENT ANALYSIS

DCD Reference	Design Feature	Value
Figure 6.3-1	The maximum elevation of the IRWST injection lines (from the connection to the IRWST to the reactor vessel) and the containment recirculation lines (from the containment to the IRWST injection lines) is less than the bottom inside surface of the IRWST.	
Figure 6.3-1	The maximum elevation of the PRHR outlet line (from the PRHR to the SG) is less than the PRHR lower channel head top inside surface.	
Subsection 7.1.2.10	Isolation devices are used to maintain the electrical independence of divisions and to see that no interaction occurs between nonsafety-related systems and the safety-related system. Isolation devices serve to prevent credible faults in circuit from propagating to another circuit.	
Subsection 7.1.4.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire, flooding, explosions, missiles, electrical faults and pipe whip.	
Subsection 7.1.2	The flexibility of the protection and safety monitoring system enables physical separation of redundant divisions.	
Subsection 7.2.2.2.1	The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level.	
Subsection 7.2.2.2.8	The reactor is tripped by actuating one of two manual reactor trip controls from the main control room.	
Subsection 7.3.1.2.2	The in-containment refueling water storage tank is aligned for injection upon actuation of the fourth stage automatic depressurization system via the protection and safety monitoring system.	
Subsection 7.3.1.2.3	The core makeup tanks are aligned for operation on a safeguards actuation signal or on a low-2 pressurizer level signal via the protection and safety monitoring system.	
Subsection 7.3.1.2.4	The fourth stage valves of the automatic depressurization system receive a signal to open upon the coincidence of a low-2 core makeup tank water level in either core makeup tank and low reactor coolant system pressure following a preset time delay after the third stage depressurization valves receive a signal to open via the protection and safety monitoring system.	

PTN DEP 7.3-1

TABLE 14.3-2R (SHEET 3 OF 4)
DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
DCD Section	7.3.1.2.4	The first stage valves of the automatic depressurization system open upon receipt of a signal generated from a core makeup tank injection alignment signal coincident with core makeup tank water level less than the Low-1 setpoint in either core makeup tank via the protection and safety monitoring system.	
DCD Section	7.3.1.2.4	The second and third stage valves open on time delays following generation of the first stage actuation signal via the protection and safety monitoring system.	
DCD Section	7.3.1.2.5	The reactor coolant pumps are tripped upon generation of a safeguards actuation signal or upon generation of a low-2 pressurizer water level signal.	
DCD Section	7.3.1.2.7	The passive residual heat removal heat exchanger control valves are opened on low steam generator water level or on a CMT actuation signal via the protection and safety monitoring system.	
DCD Section	7.3.1.2.9	The containment recirculation isolation valves are opened on a safeguards actuation signal in coincidence with low-3 in-containment refueling water storage tank water level via the protection and safety monitoring system.	
DCD/ FSAR Section	7.3.1.2.14	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, low input voltage to the 1E dc uninterruptible power supply battery chargers or if the source range flux doubling logic is blocked during shutdown.	
DCD Section	7.3.1.2.15	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protection and monitoring system derived from a source range flux doubling, high-2 pressurizer level, high-2 steam generator level signal, a safeguards signal coincident with high-1 pressurizer level, or high-2 containment radioactivity.	
DCD Section	7.3.2.2.1	The protection and monitoring system automatically generate an actuation signal for an engineered safety feature whenever a monitored condition reaches a preset level.	
DCD Section	7.3.2.2.9	Manual initiation at the system-level exists for the engineered safety features actuation.	

PTN DEP 7.3-1

TABLE 14.3-2R (SHEET 4 OF 4)
DESIGN BASIS ACCIDENT ANALYSIS

Reference		Design Feature	Value
DCD/ FSAR Section	9.3.6.7	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, low input voltage to the 1E dc and uninterruptible power supply battery chargers, a safety injection signal or if the source range flux doubling logic is blocked during shutdown conditions.	
DCD Section	9.3.6.7	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protection and safety monitoring system derived from a source range flux doubling, high-2 pressurizer level, high steam generator level signal, or a safeguards signal coincident with high-1 pressurizer level.	
DCD Section	10.1.2	Safety valves are provided on both main steam lines.	
DCD Section	10.2.2.4.3	The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. The stop valves are closed by actuation of the emergency trip system devices.	
DCD Section	10.3.1.1	The main steam supply system is provided with a main steam isolation valve and associated MSIV bypass valve on each main steam line from its respective steam generator.	
DCD Section	10.3.1.1	A main steam isolation valve (MSIV) on each main steam line prevents the uncontrolled blowdown of more than one steam generator and isolates nonsafety-related portions of the system.	
DCD Section	10.3.1.2	Power-operated atmospheric relief valves are provided to allow controlled cooldown of the steam generator and the reactor coolant system when the condenser is not available.	
DCD Section	10.3.2.1	The main steam supply system includes: - One main steam isolation valve and one main steam isolation valve bypass valve per main steam line. - Main steam safety valves. - Power-operated atmospheric relief valves and upstream isolation valves.	
DCD Section	10.3.2.3.2	In the event that a design basis accident occurs, which results in a large steam line break, the main steam isolation valves with associated main steam isolation bypass valves automatically close.	

TABLE 14.3-7R (SHEET 1 OF 2)
RADIOLOGICAL ANALYSIS

DCD Reference	Design Feature	Value
Table 2-1	Plant elevation for maximum flood level (ft)	≤ 100
Section 2.3.4	Atmospheric dispersion factors - X/Q (sec/m^3) • Site Boundary X/Q 0 – 2 hour time interval • Low Population Zone Boundary X/Q 0 – 8 hours 8 – 24 hours 24 – 96 hours 96 – 720 hours	 ≤ 5.1 x 10^{-4} ≤ 2.2 x 10^{-4} ≤ 1.6 x 10^{-4} ≤ 1.0 x 10^{-4} ≤ 8.0 x 10^{-5}
Table 6.2.3-1	Containment penetration isolation features are configured as in Table 6.2.3-1	
Table 6.2.3-1	Maximum closure time for remotely operated containment purge valves (seconds)	≤ 10
Table 6.2.3-1	Maximum closure time for all other remotely operated containment isolation valves (seconds)	≤ 60
Section 6.4.2.3	The minimum storage capacity of all storage tanks in the VES (scf)	≥ 327,574
PTN DEP 6.4-2 Deleted		
Section 6.4.4	The maximum temperature in the instrumentation and control rooms and dc equipment rooms following a loss of the nuclear island nonradioactive ventilation system remains over a 72-hour period (°F).	≤ 120
Section 6.4.4	The main control emergency habitability system nominally provides 65 scfm of ventilation air to the main control room from the compressed air storage tanks.	65 ± 5
Section 6.4.4	Sixty-five ± five scfm of ventilation flow is sufficient to pressurize the control room to 1/8th inch water gauge differential pressure (WIC).	1/8th
PTN DEP 6.4-2 Section 6.4.5.1	The maximum temperature in the main control room pressure boundary following a loss of the nuclear island nonradioactive ventilation system over a 72-hour period (°F). (dry bulb temperature)	95
Figure 6.4-2	The main control room emergency habitability system consists of two sets of emergency air storage tanks and an air delivery system to the main control room.	
Section 6.5.3	The passive heat removal process and the limited leakage from the containment result in offsite doses less than the regulatory guideline limits.	

TABLE 14.3-7R (SHEET 2 OF 2)
RADIOLOGICAL ANALYSIS

Reference	Design Feature	Value
Section 8.3.1.1.6	Electrical penetrations through the containment can withstand the maximum short-circuit currents available either continuously without exceeding their thermal limit, or at least longer than the field cables of the circuits so that the fault or overload currents are interrupted by the protective devices prior to a potential failure of a penetration.	
PTN DEP 6.4-1 Section 9.4.1.1.1	The VBS isolates the HVAC ductwork that penetrates the main control room boundary on High-2 particulate or iodine concentrations in the main control room supply air or on extended loss of ac power to support operation of the main control room emergency habitability system.	
Section 12.3.2.2.1	During reactor operation, the shield building protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete shield building wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the shield building to less than 0.25 mrem/hr from sources inside containment. The shield building completely surrounds the reactor components.	
Section 12.3.2.2.2	The reactor vessel is shielded by the concrete primary shield and by the concrete secondary shield which also surrounds other primary loop components. The secondary shield is a structural module filled with concrete surrounding the reactor coolant system equipment, including piping, pumps and steam generators. Extensive shielding is provided for areas surrounding the refueling cavity and the fuel transfer canal to limit the radiation levels.	
Section 12.3.2.2.3	Shielding is provided for the liquid radwaste, gaseous radwaste and spent resin handling systems consistent with the maximum postulated activity. Corridors are generally shielded to allow Zone II access, and operator areas for valve modules are generally Zone II or III for access. Shielding is provided to attenuate radiation from normal residual heat removal equipment during shutdown cooling operations to levels consistent with radiation zoning requirements of adjacent areas.	

Table 14.3-201
ITAAC Screening Summary

PTN SUP 14.3-2

Structure/ System Acronym	Structure/System Description	Selected for ITAAC
DRS	Storm Drain System	XX
MES	Meteorological and Environmental Monitoring System	XX
RWS	Raw Water System	XX
TVS	Closed Circuit TV System	XX
VPS	Pump House Building Ventilation System	NA
YFS	Yard Fire Water System	XX
ZBS	Transmission Switchyard and Offsite Power System	XX
ZRS	Offsite Retail Power System	NA

Legend:
XX = Site-specific system selected for ITAAC — title only, no entry for COLA
XX = Selected for ITAAC
NA = System is not part of Turkey Point Units 6 & 7 design

14.4 COMBINED LICENSE APPLICANT RESPONSIBILITIES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

14.4.1 ORGANIZATION AND STAFFING

STD COL 14.4-1
PTN COL 14.4-1

This COL Item is addressed in Section 14.2.

14.4.2 TEST SPECIFICATIONS AND PROCEDURES

STD COL 14.4-2

Preoperational and startup test specifications and procedures are provided to the NRC in accordance with the requirements of DCD Subsection 14.2.3. The controls for development of test specifications and procedures are also described in Subsection 14.2.3.

A cross reference list is provided between ITAACs and test procedures and/or sections of test procedures.

14.4.3 CONDUCT OF TEST PROGRAM

STD COL 14.4-3

A site-specific startup administration manual (procedure), which contains the administration procedures and requirements that govern the activities associated with the plant initial test program, as described in FSAR Section 14.2, is provided.

14.4.4 REVIEW AND EVALUATION OF TEST RESULTS

STD COL 14.4-4

Review and evaluation of individual test results, as well as final review of overall test results and selected milestones or hold points is addressed in Subsection 14.2.3.2. Test exceptions or results that do not meet acceptance criteria are identified to the affected and responsible design organizations, and corrective actions and retests, as required, are performed.

14.4.5 INTERFACE REQUIREMENTS

STD COL 14.4-5 This COL Item is addressed in Subsections 14.2.9.4.15, 14.2.9.4.22 through 14.2.9.4.27, 14.2.10.4.29 and in the Physical Security Plan.

14.4.6 FIRST-PLANT-ONLY AND THREE-PLANT-ONLY TESTS

STD COL 14.4-6 First-plant-only and first-three-plant-only tests either are performed in accordance with DCD Section 14.2.5 or a justification is provided that the results of the first-plant-only and first-three-plant-only tests are applicable to a subsequent plant. If the tests are not performed, the justification is provided prior to preoperational testing.

APPENDIX 14A DESIGN ACCEPTANCE CRITERIA/ITAAC CLOSURE PROCESS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

CHAPTER 15: ACCIDENT ANALYSES
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CHAPTER 15 ACCIDENT ANALYSES

15.0 ACCIDENT ANALYSES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.0.3.2 Initial Conditions

Add the following paragraph at the end of DCD Subsection 15.0.3.2.

STD COL 15.0-1

The plant operating instrumentation selected for feedwater flow measurement is a Caldon [Cameron] LEFM CheckPlus System (Reference 201), which will be calibrated (in a certified laboratory using a piping configuration representative of the plant piping design) prior to installation and will be tested after installation in the plant in accordance with the LEFM CheckPlus commissioning procedure. This selected plant operating instrumentation has documented instrumentation uncertainties to calculate a power calorimetric uncertainty that confirms the 1% uncertainty assumed for the initial reactor power in the safety analysis bounds the calculated calorimetric power measurement uncertainty values. This calculated calorimetric is done in accordance with a previously accepted Westinghouse methodology (Reference 202). Administrative controls implement maintenance and contingency activities related to the power calorimetric instrumentation.

15.0.11.1 FACTRAN Computer Code

Revise the first bullet of DCD Subsection 15.0.11.1 to read as follows:

PTN DEP 6.4-1

- A sufficiently large number of radial space increments to handle fast transients

---

Add the Subsection 15.0.11.6 following DCD Subsection 15.0.11.5 as follows:

15.0.11.6 ANC Computer Code

PTN DEP 6.4-1

The ANC computer code is used to solve the two-group neutron diffusion equation in three spatial dimensions. ANC can also solve the three-dimensional kinetics equations for six delayed neutron groups.

15.0.13 OPERATOR ACTIONS

Revise the first sentence of the first paragraph of DCD Subsection 15.0.13 as follows:

PTN DEP 3.2-1

For events where the PRHR heat exchanger is actuated, the plant automatically cools down to a safe, stable shutdown condition.

Revise the first sentence of the second paragraph of DCD Subsection 15.0.13 as follows:

PTN DEP 3.2-1

However, for these events, operator actions are not required to maintain the plant in a safe and stable condition for at least 72 hours.

15.0.15 COMBINED LICENSE INFORMATION

Add the following text to the end of DCD Subsection 15.0.15.1.

STD COL 15.0-1

This COL item is addressed in FSAR Subsection 15.0.3.2.

15.0.16 REFERENCES

Add the following text to the end of DCD Subsection 15.0.16.

201. Final Safety Evaluation for Cameron Measurement Systems Engineering Report ER-157P, Rev. 8, *Caldon Ultrasonics Engineering Report ER-157P, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check or CheckplusTM System*, (TAC No. ME1321), NRC ADAMS Accession No. ML102160694. August 16, 2010.

202. Final Safety Evaluation for Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2) – Issuance of Amendment re: 1.4-Percent Power Uprate and Revised BVPS-2 Heatup and Cooldown Curves, NRC ADAMS Accession No. ML012490569, September 24, 2001.

PTN DEP 6.4-1

TABLE 15.0-2R
SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.4	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant	NA	NA	–	NA	0 and 3415
	Inadvertent loading and operation of a fuel assembly in an improper position	ANC	NA	–	NA	3415
	Spectrum of RCCA ejection accidents	ANC, VIPRE	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8
15.5	Increase in reactor coolant inventory					
	Inadvertent operation of the emergency core cooling system during power operation	LOFTRAN	0.0	–	Upper curve of Figure 15.04-1	3483.3 (a)
	Chemical and volume control system malfunction that increases reactor coolant inventory	LOFTRAN	0.0	–	Upper curve of Figure 15.04-1	3483.3 (a)

15.1 INCREASE IN HEAT REMOVAL FROM THE PRIMARY SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.1.5.4.1 Source Term

Revise the fourth paragraph of DCD Subsection 15.1.5.4.1 to read as follows:

PTN DEP 6.4-1 The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The reactor coolant alkali metal concentrations are based on those associated with the design basis fuel defect level.

Revise the last paragraph of DCD Subsection 15.1.5.4.1 to read as follows:

PTN DEP 6.4-1 The secondary coolant is assumed to have an iodine source term of 0.01 µCi/g dose equivalent I-131. This is 1 percent of the maximum primary coolant activity at equilibrium operating conditions. The secondary coolant alkali metal concentration is also assumed to be 1 percent of the primary concentration.

15.1.5.4.6 Doses

Revise the text of DCD Subsection 15.1.5.4.6 to read as follows:

PTN DEP 6.4-1 Using the assumptions from Table 15.1.5-1, the calculated total effective dose equivalent (TEDE) doses for the case with accident-initiated iodine spike are determined to be less than 0.6 rem at the site boundary for the limiting 2-hour interval (4.8 to 6.8 hours) and 1.1 rem at the low population zone outer boundary. These doses are small fractions of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A "small fraction" is defined, consistent with the Standard Review Plan, as being 10 percent or less. The TEDE doses for the case with pre-existing iodine spike are determined to be less than 0.5 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 0.4 rem at the low population

zone outer boundary. These doses are within the dose guidelines of 10 CFR Part 50.34.

At the time the main steam line break occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. The 30-day contribution to the dose at the site boundary and the low population zone boundary is less than 0.01 rem TEDE. When this is added to the dose calculated for the main steam line break, the resulting total dose remains less than the values reported above.

PTN DEP 6.4-1

TABLE 15.1.5-1R
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A MAIN STEAM LINE BREAK

Reactor coolant iodine activity	
- Accident-initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 µCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Appendix 15A). Duration of spike is 5 hours.
- Preaccident spike	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 µCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 µCi/g dose equivalent Xe-133.
Reactor coolant alkali metal activity	Design basis activity (see DCD Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	1% of reactor coolant concentrations at maximum equilibrium conditions
Duration of accident (hr)	72
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in DCD Appendix 15A
Steam generator in faulted loop	
- Initial water mass (lb)	3.32 E+05
- Primary to secondary leak rate (lb/hr)	52.25[a]
- Iodine partition coefficient	1.0
- Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.321E+05 3.66 E+03
Steam generator in intact loop	
- Primary to secondary leak rate (lb/hr)	52.25[a]
- Iodine partition coefficient	1.0
- Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.321E+05 3.66 E+03
Nuclide data	See DCD Table 15A-4

Note: a. Equivalent to 150 gpd cooled liquid at 62.4 lb/ft^3.

15.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

Insert the following as a new third paragraph of DCD Section 15.2:

PTN DEP 3.2-1

For events in this section where PRHR HX actuation occurs, transients are presented until the PRHR HX heat removal matches decay heat generation. After that point in time, PRHR HX performance is driven by the performance of the passive containment cooling systems to control containment pressure and the ability of the condensate collection features to return condensate to the in-containment refueling water storage tank. The performance of these systems, for extended decay heat removal, is described in Subsection 6.3.1.1.1.

15.2.6.1 Identification of Causes and Accident Description

Revise the seventh sentence of the fourth paragraph of DCD Subsection 15.2.6.1 as follows:

PTN DEP 6.3-1

The PRHR heat exchanger, in conjunction with the passive containment cooling system, provides core cooling and maintains reactor coolant system conditions to satisfy the evaluation criteria.

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.3.3.3.1 Source Term

Revise the last paragraph of DCD Subsection 15.3.3.3.1 to read as follows:

PTN DEP 6.4-1 The initial secondary coolant activity is assumed to be 1 percent of the maximum equilibrium primary coolant activity for iodines and alkali metals.

PTN DEP 6.4-1

TABLE 15.3-3R
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 µCi/gm of dose equivalent I-131 (see Appendix 15A)[a)]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 µCi/gm dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	1% of design basis reactor coolant concentrations at maximum equilibrium conditions
Fraction of fuel rods assumed to fail	0.10
Core activity	See Table 15A-3
Radial peaking factor (for determination of activity in failed fuel rods)	1.75
Fission product gap fractions	
I-131	0.08
Kr-85	0.10
Other iodines and noble gases	0.05
Alkali metals	0.12
Reactor coolant mass (lb)	3.7 E+05
Secondary coolant mass (lb)	6.04 E+05
Condenser	Not available
Atmospheric dispersion factors	See Table 15A-5
Primary to secondary leak rate (lb/hr)	104.5[(b)]
Partition coefficient in steam generators	
iodine	0.01
alkali metals	0.0035
Accident scenario in which startup feedwater is not available	
Duration of accident (hr)	1.5 hr
Steam released (lb)	
0-1.5 hours[(c)]	6.48 E+05
Leak flashing fraction[(d)]	
0-60 minutes	0.04
> 60 minutes	0

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.4.8.1.1.3 Reactor Protection

Revise DCD Subsection 15.4.8.1.1.3 to read as follows:

PTN DEP 6.4-1 The reactor protection in the event of a rod ejection accident is described in WCAP-15806-P-A (Reference 4). The protection for this accident is provided by the high neutron flux trip (high and low setting) and the high rate of neutron flux increase trip. These protection functions are described in DCD Section 7.2.

15.4.8.1.2 Limiting Criteria

Revise DCD Subsection 15.4.8.1.2 to read as follows:

PTN DEP 6.4-1 This event is a Condition IV incident (ANSI N18.2). See DCD Subsection 15.0.1 for a discussion of ANS classification. Because of the extremely low probability of an RCCA ejection accident, some fuel damage is considered an acceptable consequence.

NUREG-0800 Standard Review Plan (SRP) 4.2, Revision 3 (Reference 24), interim criteria applicable to new plant design certification are applied to provide confidence that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are the following:

- The pellet clad mechanical interaction (PCMI) failure criteria is a change in radial average fuel enthalpy greater than the corrosion-dependent limit depicted in Figure B-1 of SRP 4.2, Revision 3, Appendix B.
- The high cladding temperature failure criteria for zero-power conditions is a peak radial average fuel enthalpy greater than 170 cal/g for fuel rods with an

internal rod pressure at or below system pressure and 150 cal/g for fuel rods with an internal rod pressure exceeding system pressure.

- For intermediate (greater than 5-percent rated thermal power) and full-power conditions, fuel cladding is presumed to fail if local heat flux exceeds thermal design limits (e.g., DNBR).
- For core coolability, it is conservatively assumed that the average fuel pellet enthalpy at the hot spot remains below 200 cal/g (360 Btu/lb) for irradiated fuel. This bounds non-irradiated fuel, which has a slightly higher enthalpy limit.
- For core coolability, the peak fuel temperature must remain below incipient fuel melting conditions.
- Mechanical energy generated as a result of (1) non-molten fuel-to-coolant interaction and (2) fuel rod burst that must be addressed with respect to reactor pressure boundary, reactor internals, and fuel assembly structural integrity.
- No loss of coolable geometry due to (1) fuel pellet and cladding fragmentation and dispersal and (2) fuel rod ballooning.
- Peak reactor coolant system pressure is less than that which could cause stresses to exceed the "Service Limit C" as defined in the ASME code.

15.4.8.2 Analysis of Effects and Consequences

Revise DCD Subsection 15.4.8.2 to read as follows:

PTN DEP 6.4-1

Method of Analysis

The calculation of the RCCA ejection transients is performed in two stages: first, an average core calculation and then, a hot rod calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time, including the various total core feedback effects (Doppler reactivity and moderator reactivity). Enthalpy, fuel temperature, and DNB transients are then determined by performing a conservative fuel rod transient heat transfer calculation.

A discussion of the method of analysis appears in WCAP-15806-P-A (Reference 4).

Average Core Analysis

The three-dimensional nodal code ANC (References 14, 15, 16, 17, 21, 22, and 27) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in three spatial dimensions (rectangular coordinates) for six delayed neutron groups. The core moderator and fuel temperature feedbacks are based on the NRC approved Westinghouse version of the VIPRE-01 code and methods (References 18 and 19).

Hot Rod Analysis

The hot fuel rod models are based on the Westinghouse VIPRE models described in WCAP-15806-P-A (Reference 4). The hot rod model represents the hottest fuel rod from any channel in the core. VIPRE performs the hot rod transients for fuel enthalpy, temperature, and DNBR using as input the time dependent nuclear core power and power distribution from the core average analysis. A description of the VIPRE code is provided in Reference 18.

System Overpressure Analysis

If the fuel coolability limits are not exceeded, the fuel dispersal into the coolant or a sudden pressure increase from thermal to kinetic energy conversion is not needed to be considered in the overpressure analysis. Therefore, the overpressure condition may be calculated on the basis of conventional fuel rod to coolant heat transfer and the prompt heat generation in the coolant. The system overpressure analysis is conducted by first performing the core power response analysis to obtain the nuclear power transient (versus time) data. The nuclear power data is then used as input to a plant transient computer code to calculate the peak reactor coolant system pressure.

This code calculates the pressure transient, taking into account fluid transport in the reactor coolant system and heat transfer to the steam generators. For conservatism, no credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

15.4.8.2.1 Calculation of Basic Parameters

Revise DCD Subsection 15.4.8.2.1 to read as follows:

PTN DEP 6.4-1 Input parameters for the analysis are conservatively selected as described in Reference 4. DCD Table 15.4-3 is deleted and not used.

15.4.8.2.1.1 Ejected Rod Worths and Hot Channel Factors

Revise DCD Subsection 15.4.8.2.1.1 to read as follows:

PTN DEP 6.4-1 The values for ejected rod worths and hot channel factors are calculated using three-dimensional static methods. Standard nuclear design codes are used in the analysis. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate safety analysis allowances are added to the ejected rod worth and hot channel factors to account for calculational uncertainties, including an allowance for nuclear peaking due to densification as discussed in Reference 4.

15.4.8.2.1.2 Reactivity Feedback Weighting Factors

Revise DCD Subsection 15.4.8.2.1.2 to read as follows:

PTN DEP 6.4-1 15.4.8.2.1.2 Not Used

15.4.8.2.1.3 Moderator and Doppler Coefficients

Revise DCD Subsection 15.4.8.2.1.3 to read as follows:

PTN DEP 6.4-1 The critical boron concentration is adjusted in the nuclear code to obtain a moderator temperature coefficient that is conservative compared to actual design conditions for the plant consistent with Reference 4. The fuel temperature feedback in the neutronics code is reduced consistent with Reference 4 requirements.

15.4.8.2.1.4 Delayed Neutron Fraction, β_{eff}

Revise DCD Subsection 15.4.8.2.1.4 to read as follows:

PTN DEP 6.4-1 Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.50 percent at end of cycle. The accident is sensitive to β_{eff} if the ejected rod worth is equal to or greater than β_{eff}. To allow for future cycles, a pessimistic estimate of β_{eff} of 0.44 percent is used in the analysis.

15.4.8.2.1.5 Trip Reactivity Insertion

Revise the first paragraph of DCD Subsection 15.4.8.2.1.5 to read as follows:

PTN DEP 6.4-1 The trip reactivity insertion accounts for the effect of the ejected rod and one adjacent stuck rod. The trip reactivity is simulated by dropping a limited set of rods of the required worth into the core. The start of rod motion occurs 0.9 second after the high neutron flux trip setpoint is reached. This delay is assumed to consist of 0.583 second for the instrument channel to produce a signal, 0.167 second for the trip breakers to open, and 0.15 second for the coil to release the rods. A curve of trip rod insertion versus time is used, which assumes that insertion to the dashpot does not occur until 2.47 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over 1 second after the trip setpoint is reached before significant shutdown reactivity is inserted into the core. This conservatism is important for the hot full power accidents.

15.4.8.2.1.7 Results

Revise DCD Subsection 15.4.8.2.1.7 to read as follows:

PTN DEP 6.4-1 For all cases, the core is preconditioned by assuming a fuel cycle depletion with control rod insertion that is conservative relative to expected baseload operation. All cases assume that the mechanical shim and axial offset control RCCAs are inserted to their insertion limits before the event and xenon is skewed to yield a conservative initial axial power shape. The limiting RCCA ejection cases for a typical cycle are summarized following the criteria outlined in Subsection 15.4.8.1.2.

- PCMI and high cladding temperature (hot zero power)

The resulting maximum fuel average enthalpy rise and maximum fuel average enthalpy are less than the criteria given in Subsection 15.4.8.1.2.

- High cladding temperature (≥ 5% rated thermal power)

  The fraction of the core calculated to have a DNBR less than the safety analysis limit is less than the amount of failed fuel assumed in the dose analysis described in Subsection 15.4.8.3.

- Core coolability

  The resulting maximum fuel average enthalpy is less than the criterion given in Subsection 15.4.8.1.2. Fuel melting is not predicted to occur at the hot spot.

There are no fuel failures due to the fuel enthalpy deposition, i.e., both fuel and cladding enthalpy limits were met. Additionally, the coolability criteria for peak fuel enthalpy and the fuel melting criteria were met. Therefore, the fuel dispersal into the coolant, a sudden pressure increase from thermal to kinetic energy conversion, gross lattice distortion, or severe shock waves are precluded.

The nuclear power and fuel transients for the limiting cases are presented in Figures 15.4.8-1R through 15.4.8-3R.

The calculated sequence of events for the limiting cases is presented in Table 15.4-1R. Reactor trip occurs early in the transients, after which the nuclear power excursion is terminated.

The ejection of an RCCA constitutes a break in the reactor coolant system, located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents (LOCAs) are discussed in DCD Subsection 15.6.5. Following the RCCA ejection, the plant response is the same as a LOCA.

The consequential loss of offsite power described in DCD Subsection 15.0.14 is not limiting for the enthalpy and temperature transients resulting from an RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the peak fuel and cladding temperatures occur before the reactor coolant pumps begin to coast down.

15.4.8.2.1.8 Fission Product Release

Revise the first paragraph of DCD Subsection 15.4.8.2.1.8 to read as follows:

PTN DEP 6.4-1

It is assumed that fission products are released from the gaps of all rods entering DNB. In the cases considered, less than 10 percent of the rods are assumed to enter DNB based on a detailed three-dimensional kinetics and hot rod analysis. The maximum fuel average enthalpy rise of rods predicted to enter DNB will be less than 60 cal/g. Fuel melting does not occur at the hot spot.

15.4.8.2.1.9 Peak Reactor Coolant System Pressure

Revise first paragraph DCD Subsection 15.4.8.2.1.9 to read as follows:

PTN DEP 6.4-1

Calculations of the peak reactor coolant system pressure demonstrate that the peak pressure does not exceed that which would cause the stress to exceed the Service Level C Limit as described in the ASME Code, Section III. Therefore, the accident for this plant does not result in an excessive pressure rise or further damage to the reactor coolant system.

15.4.8.3 Radiological Consequences

Revise the first two paragraphs of DCD Subsection 15.4.8.3 to read as follows:

PTN DEP 6.4-1

The evaluation of the radiological consequences of a postulated rod ejection accident assumes that the reactor is operating with a limited number of fuel rods containing cladding defects and that leaking steam generator tubes result in a buildup of activity in the secondary coolant. See Subsection 15.4.8.3.1 and Table 15.4-4R.

As a result of the accident, 10 percent of the fuel rods are assumed to be damaged (see Subsection 15.4.8.2.1.8) such that the activity contained in the fuel cladding gap is released to the reactor coolant. No fuel melt is calculated to occur as a result of the rod ejection (see Subsection 15.4.8.2.1.8).

15.4.8.3.1 Source Term

Revise DCD Subsection 15.4.8.3.1 to read as follows:

PTN DEP 6.4-1

The significant radionuclide releases due to the rod ejection accident are the iodines, alkali metals, and noble gases. The reactor coolant iodine source term assumes a pre-existing iodine spike. The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The initial reactor coolant alkali metal concentrations are assumed to be those associated with the design fuel defect level. These initial reactor coolant activities are of secondary importance compared to the release of fission products from the portion of the core assumed to fail.

Based on NUREG-1465 (Reference 12), the fission product gap fraction is 3 percent of fuel inventory. For this analysis, the gap fractions are modified following the guidance of DG-1199 (Reference 25), which incorporates the effects of enthalpy rise in the fuel following the reactivity insertion, consistent with Appendix B of SRP 4.2, Revision 3 (Reference 24). DG-1199 included expanded guidance for determining nuclide gap fractions available for release following a rod ejection. Reference 26 was issued as a clarification to the gap fraction guidance in DG-1199. An enthalpy rise of 60 cal/gm is used to calculate the gap fractions (see Subsection 15.4.8.2.1.8). Also, to address the fact that the failed fuel rods may have been operating at power levels above the core average, the source term is increased by the lead rod radial peaking factor. No fuel melt is calculated to occur as a result of the rod ejection (see Subsection 15.4.8.2.1.8).

15.4.8.3.5 Identification of Conservatisms

Revise second bullet of DCD Subsection 15.4.8.3.5 to read as follows:

PTN DEP 6.4-1

- The reactor coolant activities are based on conservative assumptions (refer to Table 15.4-4R); whereas, the activities based on the expected fuel defect level are far less (see DCD Section 11.1).

15.4.8.3.6 Doses

Revise the first paragraph of DCD Subsection 15.4.8.3.6 to read as follows:

PTN DEP 6.4-1

Using the assumptions from Table 15.4-4R, the calculated total effective dose equivalent (TEDE) doses are determined to be 4.0 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 5.9 rem at the low population zone outer boundary. These doses are well within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase "well within" is taken as being 25 percent or less.

15.4.10 REFERENCES

Revise DCD Subsection 15.4.10 References 4, 7, 8, 10 and 13, and add new References 14 through 27 as follows:

PTN DEP 6.4-1

4. Beard, C. L. et al., "Westinghouse Control Rod Ejection Accident Analysis Methodology Using Multi-Dimensional Kinetics," WCAP-15806-P-A (Proprietary) and WCAP-15807-NP-A (Nonproprietary), November 2003.

7. Liu, Y. S., et al., "ANC – A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A (Proprietary) and WCAP-10966-A (Nonproprietary), September 1986.

8. Not Used.

10. American National Standards Institute N18.2, "Nuclear Safety Criteria for the Design of Stationary PWR Plants," 1973.

13. Not Used.

14. Nguyen, T. Q., et al., "Qualifications of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A (Proprietary) and WCAP-11597-A (Nonproprietary), June 1988.

15. Ouisloumen, M., et al., "Qualification of the Two-Dimensional Transport Code PARAGON," WCAP-16045-P-A (Proprietary) and WCAP-16045-NP-A (Nonproprietary), August 2004.

16. Liu, Y. S., "ANC – A Westinghouse Advanced Nodal Computer Code; Enhancements to ANC Rod Power Recovery," WCAP-10965-P-A, Addendum 1 (Proprietary) and WCAP-10966-A Addendum 1 (Nonproprietary), April 1989.

17. Letter from Liparulo, N.J. (Westinghouse) to Jones, R. C., (NRC), "Notification to the NRC Regarding Improvements to the Nodal Expansion Method Used in the Westinghouse Advanced Nodal Code (ANC)," NTD-NRC-95-4533, August 22, 1995.

18. Sung, Y. X., Schueren, P., and Meliksetian, A., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), October 1999.

19. Stewart, C. W., et al., "VIPRE-01: A Thermal/Hydraulic Code for Reactor Cores," Volumes 1, 2, 3 (Revision 3, August 1989), and Volume 4 (April 1987), NP-2511-CCM-A, Electric Power Research Institute, Palo Alto, California.

20. Foster, J. P. and Sidener, S., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1 with Errata (Proprietary) and WCAP-15064-NP-A (Nonproprietary), July 2000.

21. Zhang, B., et al., "Qualification of the NEXUS Nuclear Data Methodology," WCAP-16045-P-A, Addendum 1-A (Proprietary) and WCAP-16045-NP-A, Addendum 1-A (Nonproprietary), August 2007.

22. Zhang, B., et al., "Qualification of the New Pin Power Recovery Methodology," WCAP-10965-P-A, Addendum 2-A (Proprietary), September 2010.

23. Smith, L. D, et al., "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," WCAP-15025-P-A (Proprietary) and WCAP-15026-NP-A (Nonproprietary), April 1999.

24. NUREG-0800, Standard Review Plan, Section 4.2, Revision 3, "Fuel System Design," Appendix B, "Interim Acceptance Criteria and Guidance for the Reactivity Initiated Accidents," March 2007.

25. Draft Regulatory Guide DG-1199, "Proposed Revision 1 of Regulatory Guide 1.183; Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," October 2009. NRC ADAMS Accession Number: ML090960464.

26. NRC Memorandum from Anthony Mendiola to Travis Tate, "Technical Basis for Revised Regulatory Guide 1.183 (DG-1199) Fission Product Fuel-to-Cladding Gap Inventory," July 2011. NRC ADAMS Accession Number: ML111890397.

27. Letter from Liparulo, N. J. (Westinghouse) to Jones, R. C. (NRC), "Process Improvement to the Westinghouse Neutronics Code System," NSD-NRC-96-4679, March 29, 1996.

PTN DEP 6.4-1

TABLE 15.4-1R (SHEET 1 OF 2)
TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time (seconds)
Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant		
1. Dilution during startup	Power range – low setpoint reactor trip due to dilution	0.0
	Dilution automatically terminated by demineralized water transfer and storage system isolation	215.0
2. Dilution during full-power Operation		
a. Automatic reactor control	Operator receives low-low rod insertion limit alarm due to dilution	0.0
	Shutdown margin lost	19,680
b. Manual reactor control	Initiate dilution	0.0
	Reactor trip on overtemperature ΔT due to dilution	180.0
	Dilution automatically terminated by demineralized water transfer and storage system isolation	395.0
RCCA ejection accident		
1. PCMI limiting event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.14
	Reactor trip setpoint reached	<0.30
	Peak cladding temperature occurs	0.36
	Peak enthalpy deposition occurs	0.44
	Rods begin to fall into core	1.20

PTN DEP 6.4-1

TABLE 15.4-1R (SHEET 2 OF 2)
TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

2. Peak cladding temperature limiting event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.08
	Minimum DNBR occurs	0.11
	Peak cladding temperature occurs	0.11
	Reactor trip setpoint reached	<0.30
	Rods begin to fall into core	1.20
3. Peak enthalpy/peak fuel centerline temperature event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.06
	Reactor trip setpoint reached	<0.30
	Rods begin to fall into core	1.20
	Peak fuel center temperature occurs	2.50
	Peak cladding temperature occurs	2.80

PTN DEP 6.4-1

TABLE 15.4-3R
NOT USED

PTN DEP 6.4-1

TABLE 15.4-4R (SHEET 1 OF 2)
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A ROD EJECTION ACCIDENT

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 µCi/g (2.22E+06 Bq/g) of dose equivalent I-131 (see Appendix 15A)[a]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 µCi/g (1.036E+07 Bq/g) dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	1% of reactor coolant concentrations at maximum equilibrium conditions
Radial peaking factor (for determination of activity in damaged fuel)	1.75
Fuel cladding failure	
- Fraction of fuel rods assumed to fail	0.1
- Fuel enthalpy increase (cal/g)	60
- Fission product gap fractions	
Iodine 131	0.1238
Iodine 132	0.1338
Krypton 85	0.5120
Other noble gases	0.1238
Other halogens	0.0938
Alkali metals	0.6860
Iodine chemical form (%)	
- Elemental	4.85
- Organic	0.15
- Particulate	95.0
Core Activity	See Table 15A-3
Nuclide data	See Table 15A-4
Reactor coolant mass (lb)	3.7 E+05 (1.68E+05 kg)

Note:
a. The assumption of a pre-existing iodine spike is a conservative assumption for the initial reactor coolant activity. However, compared to the activity assumed to be released from damaged fuel, it is not significant.

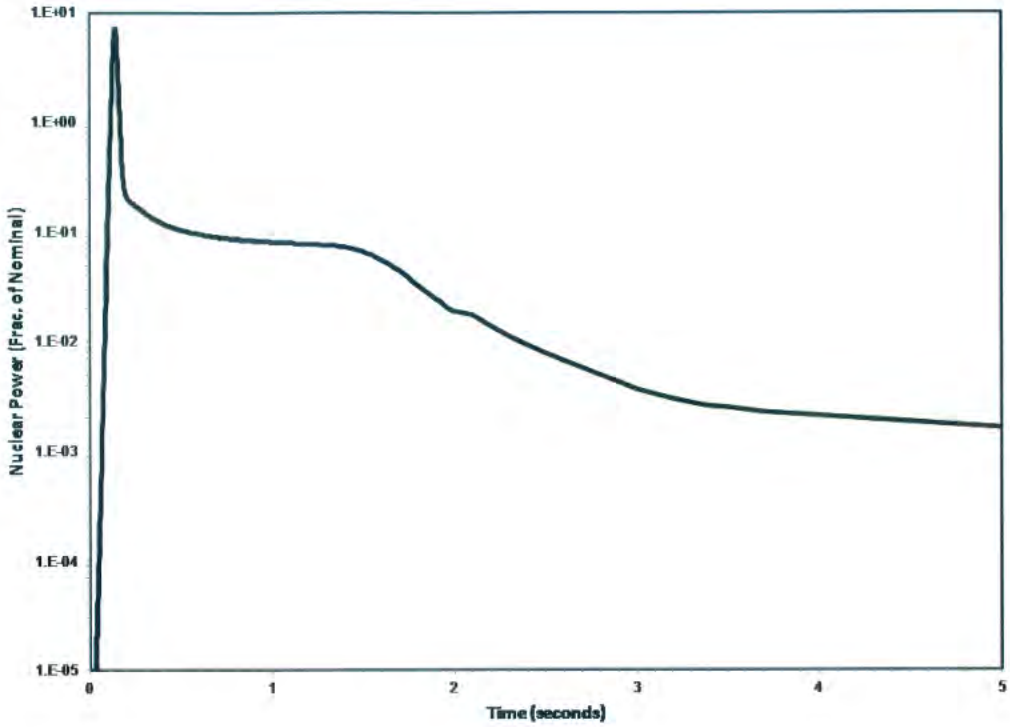
PTN DEP 6.4-1

TABLE 15.4-4R (SHEET 2 OF 2)
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A ROD EJECTION ACCIDENT

Condenser	Not available
Duration of accident (days)	30
Atmospheric dispersion (χ/Q) factors	See Table 15A-5
Secondary system release path	
- Primary to secondary leak rate (lb/hr)	104.5[a] (47.4 kg/hr)
- Leak flashing fraction	0.04[b]
- Secondary coolant mass (lb)	6.06 E+05 (2.75E+05 kg)
- Duration of steam release from secondary system (sec)	1800
- Steam released from secondary system (lb)	1.08 E+05 (4.90E+04 kg)
- Partition coefficient in steam generators	
• Iodine	0.01
• Alkali metals	0.0035
Containment leakage release path	
- Containment leak rate (% per day)	
• 0-24 hr	0.10
• >24 hr	0.05
- Airborne activity removal coefficients (hr^{-1})	
• Elemental iodine	1.9[c]
• Organic iodine	0
• Particulate iodine or alkali metals	0.1
- Decontamination factor limit for elemental iodine removal	200
- Time to reach the decontamination factor limit for elemental iodine (hr)	2.78

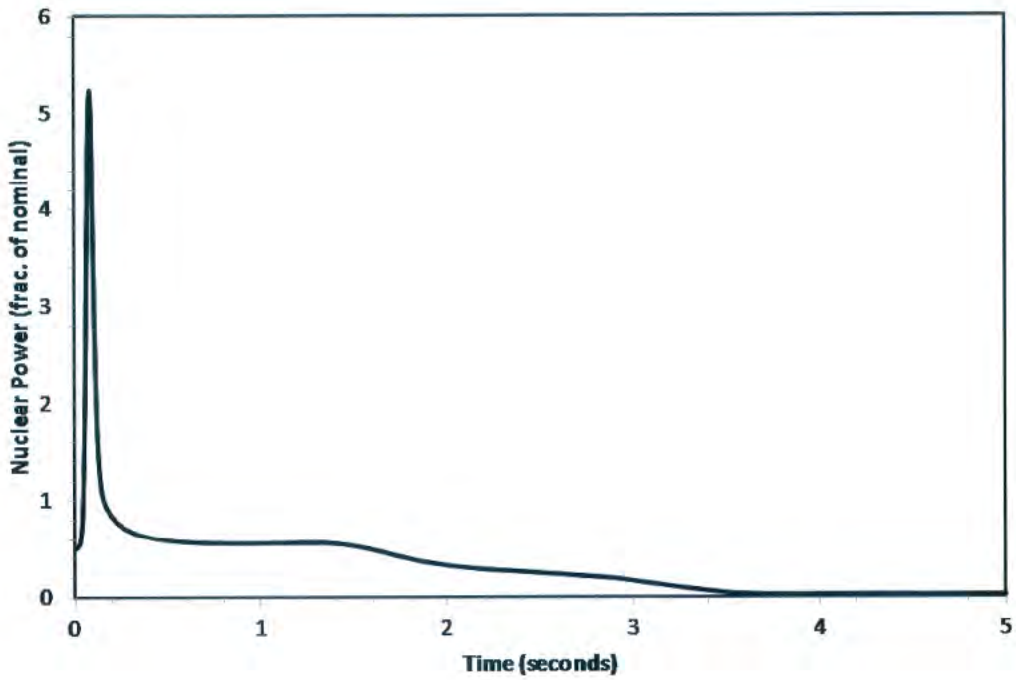
Notes:
a. Equivalent to 300 gpd (1.14 m^3/day) cooled liquid at 62.4 b/ft^3 (999.6 kg/m^3).
b. No credit for iodine partitioning is taken for flashed leakage.
c. From Appendix 15B.

PTN DEP 6.4-1 **Figure 15.4.8-1R Nuclear Power Transient Versus Time for the PCMI Rod Ejection Accident**



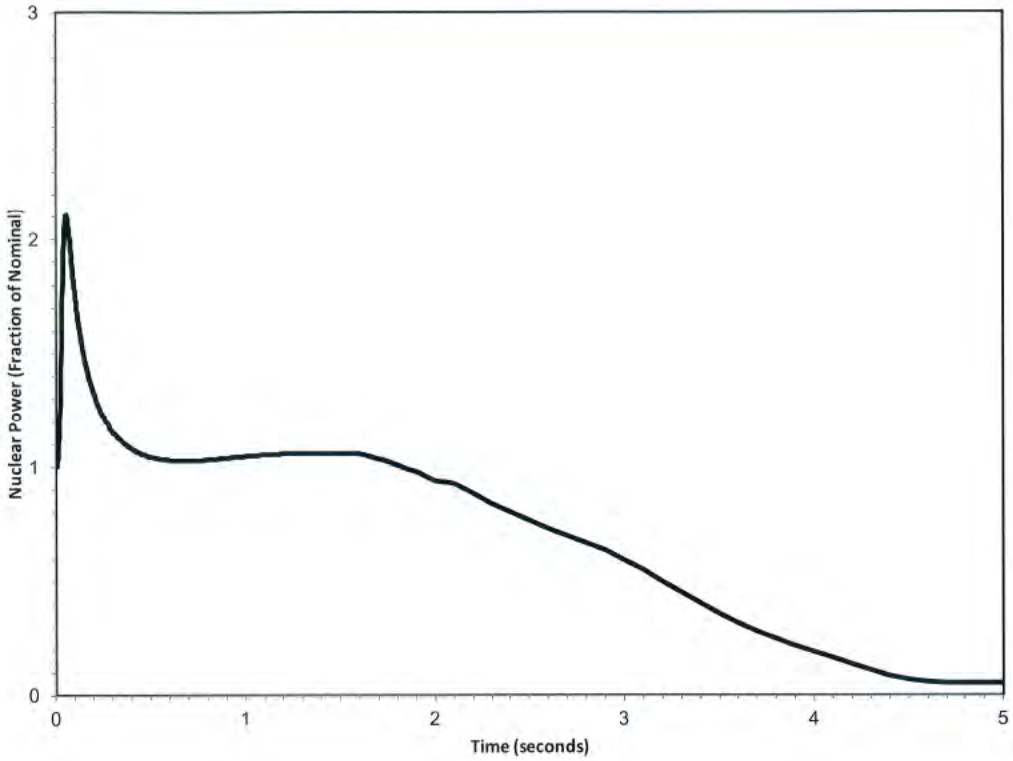
PTN DEP 6.4-1

Figure 15.4.8-2R Nuclear Power Transient Versus Time for the High Cladding Temperature Rod Ejection Accident



PTN DEP 6.4-1

Figure 15.4.8-3R Nuclear Power Transient Versus Time for the Peak Enthalpy and Fuel Centerline Temperature Rod Ejection Accident



PTN DEP 6.4-1

Figure 15.4.8-4R Not Used

15.5 INCREASE IN REACTOR COOLANT INVENTORY

This section of the referenced DCD is incorporated by reference with no departures or supplements.

15.6 DECREASE IN REACTOR COOLANT INVENTORY

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.6.2.6 Doses

Revise the first paragraph of DCD Subsection 15.6.2.6 to read as follows:

PTN DEP 6.4-1 Using the assumptions from Table 15.6.2-1R, the calculated total effective dose equivalent (TEDE) doses are determined to be 1.3 rem at the exclusion area boundary and 0.6 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase "a small fraction" is taken as being ten percent or less.

15.6.3.3.1 Source Term

Revise the last paragraph of DCD Subsection 15.6.3.3.1 to read as follows:

PTN DEP 6.4-1 The secondary coolant iodine and alkali metal activity is assumed to be 1 percent of the maximum equilibrium primary coolant activity.

15.6.3.3.6 Doses

Revise the first two paragraphs of DCD Subsection 15.6.3.3.6 to read as follows:

PTN DEP 6.4-1 Using the assumptions from Table 15.6.3-3R, the calculated TEDE doses for the case in which the iodine spike is assumed to be initiated by the accident are determined to be 0.7 rem at the exclusion area boundary for the limiting 2-hour interval (0-2 hours) and 0.5 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in

10 CFR Part 50.34. A "small fraction" is defined, consistent with the Standard Review Plan, as being ten percent or less.

For the case in which the SGTR is assumed to occur coincident with a pre-existing iodine spike, the TEDE doses are determined to be 1.4 rem at the exclusion area boundary for the limiting 2-hour interval (0 to 2 hours) and 0.7 rem at the low population zone outer boundary. These doses are within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34.

15.6.5.3.2 In-containment Activity Removal Processes

Add the following paragraphs at the end of DCD Subsection 15.6.5.3.2.

PTN DEP 6.4-1 Particulates removed from the containment atmosphere to the containment shell are assumed to be washed off the shell by the flow of water resulting from condensing steam (i.e. condensate flow). The particulates may be either washed into the sump, which is controlled to a pH ≥7 post-accident or into the IRWST, which is not pH controlled post-accident. Due to the conditions in the IRWST, a portion of the particulate iodine washed into the IRWST may chemically convert to an elemental form and re-evolve, subject to partitioning, as airborne. A water-steam partition factor of 10 for elemental iodine is applied. This value bounds the time-dependent partition factors calculated using the NUREG/CR-5950 (Reference 35) models and the calculated IRWST water temperature and pH as a function of time.

The IRWST is a closed tank with weighted louvers, and without boiling, there would be no motive force for the release of re-evolved gaseous iodine from the IRWST gas space to the containment. Thus, the assumption of boiling in the IRWST liquid is imposed to force the release of the re-evolved iodine to the containment atmosphere. A portion (3%) of the re-evolved elemental iodine is assumed to convert to an organic form upon its release to containment.

15.6.5.3.5 Main Control Room Dose Model

Revise the first sentence of the second paragraph of DCD Subsection 15.6.5.3.5 to read as follows:

PTN DEP 6.4-1 Alternatively, if the normal HVAC is inoperable or, if operable, the supplemental filtration train does not function properly resulting in increasing levels of airborne iodine in the main control room, the emergency habitability system (Section 6.4) would be actuated when High-2 iodine or particulate activity is detected.

Revise the second sentence of the fourth paragraph of DCD Subsection 15.6.5.3.5 to read as follows:

PTN DEP 6.4-1 With the VES in operation, airborne activity is removed from the main control room atmosphere via the passive recirculation filtration portion of the VES.

15.6.5.3.7.3 Atmospheric Dispersion Factors

PTN COL 2.3-4 Add the following paragraph at the end of DCD Subsection 15.6.5.3.7.3.

Site-specific X/Q (atmospheric dilution factor) values provided in Subsection 2.3.4 are bounded by the values given in DCD Table 15A-5 and Table 15A-6.

15.6.5.3.8.1 Offsite Doses

Revise the first sentence of the second paragraph of DCD Subsection 15.6.5.3.8.1 to read as follows:

PTN DEP 6.4-1 The reported exclusion area boundary doses are for the time period of 1.3 to 3.3 hours.

15.6.5.3.8.2 Doses to Operators in the Main Control Room

Revise the second and third sentence of the first paragraph of DCD Subsection 15.6.5.3.8.2 to read as follows:

PTN DEP 6.4-1 Also listed on Table 15.6.5-3R are the doses due to direct shine from the activity in the adjacent buildings, shine from radioactivity accumulated on the VES or VBS filters, and sky-shine from the radiation that streams out the top of the containment shield building and is reflected back down by air-scattering. The total of these dose paths is within the dose criteria of 5 rem TEDE as defined in GDC-19.

15.6.6 REFERENCES

Add the following to DCD Subsection 15.6.6.

PTN DEP 6.4-1 35. Beahm, E. C. et al., NUREG/CR-5950, "Iodine Evolution and pH Control," December 1992.

PTN DEP 6.4-1

TABLE 15.6.2-1R
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SMALL LINE BREAK OUTSIDE CONTAINMENT

Reactor coolant iodine activity	Initial activity equal to the design basis reactor coolant activity of 1.0 µCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Table 15A-2 in Appendix 15A)[a]
Reactor coolant noble gas activity	280 µCi/g dose equivalent Xe-133
Break flow rate (gpm)	130[b]
Fraction of reactor coolant flashing	0.47
Duration of accident (hr)	0.5
Atmospheric dispersion (X/Q) factors	See Table 15A-5
Nuclide data	See Table 15A-4

Notes:
a. Use of accident-initiated iodine sp ke is consistent with the guidance in the Standard Review Plan.
b. At density of 62.4 lb/ft^3.

PTN DEP 6.4-1

TABLE 15.6.3-3R
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A STEAM GENERATOR TUBE RUPTURE

Reactor coolant activity	
- Accident initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 µCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 335 (see Appendix 15A). Duration of spike is 8.0 hours.
- Preaccident spike	An assumed iodine spike that results in an increase in the reactor coolant activity to 60 µCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	280 µCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal	1% of reactor coolant concentrations at maximum equilibrium conditions
Reactor coolant mass (lb)	3.7 E+05
Offsite power	Lost on reactor trip
Condenser	Lost on reactor trip
Time of reactor trip	Beginning of the accident
Duration of steam releases (hr)	15.94
Atmospheric dispersion factors	See Appendix 15A
Nuclide data	See Appendix 15A
Steam generator in ruptured loop	
- Initial secondary coolant mass (lb)	1.16 E+05
- Primary-to-secondary break flow	See Figure 15.6.3-5
- Integrated flashed break flow (lb)	See Figure 15.6.3-10
- Steam released (lb)	See Table 15.6.3-2
- Iodine partition coefficient	1.0 E-02[a]
- Alkali metals partition coefficient	3.5 E-03[a]
Steam generator in intact loop	
- Initial secondary coolant mass (lb)	2.30 E+04
- Primary-to-secondary leak rate (lb/hr)	52.16[b]
- Steam released (lb)	See Table 15.6.3-2
- Iodine partition coefficient	1.0 E-02[a]
- Alkali metals partition coefficient	3.5 E-03[a]

Notes:
a. Iodine partition coefficient does not apply to flashed break flow.
b. Equivalent to 150 gpd at psia cooled liquid at 62.4 b/ft^3.

PTN DEP 6.4-1

TABLE 15.6.5-2R (SHEET 1 OF 3)
ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Primary coolant source data	
- Noble gas concentration	280 µCi/g dose equivalent Xe-133
- Iodine concentration	1.0 µCi/g dose equivalent I-131
- Primary coolant mass (lb)	4.39 E+05
Containment purge release data	
- Containment purge flow rate (cfm)	16000
- Time to isolate purge line (seconds)	30
- Time to blow down the primary coolant system (minutes)	10
- Fraction of primary coolant iodine that becomes airborne	1.0
Core source data	
- Core activity at shutdown	See Table 15A-3
- Release of core activity to containment atmosphere (timing and fractions)	See Table 15.6.5-1
- Iodine species distribution (%)	
• Elemental	4.85
• Organic	0.15
• Particulate	95
Containment leakage release data	
- Containment volume (ft^3)	2.06 E+06
- Containment leak rate, 0-24 hr (% per day)	0.10
- Containment leak rate, > 24 hr (% per day)	0.05
- Elemental iodine deposition removal coefficient (hr^{-1})	1.9
- Decontamination factor limit for elemental iodine removal	200
- Removal coefficient for particulates (hr^{-1})	See Appendix 15B
Main control room model	
- Main control room volume (ft^3)	3.89 E+04
- Volume of HVAC, including main control room and control support area (ft^3)	1.2 E+05
- Normal HVAC operation (prior to switchover to an emergency mode)	
• Air intake flow (cfm)	1650
• Filter efficiency	Not applicable
- Atmospheric dispersion factors (sec/m^3)	See Table 15A-6

PTN DEP 6.4-1

TABLE 15.6.5-2R (SHEET 2 OF 3)
ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Main control room model (cont.)	
- Occupancy	
• 0 - 24 hr	1.0
• 24 - 96 hr	0.6
• 96 - 720 hr	0.4
- Breathing rate (m^3/sec)	3.5 E-04
Control room with emergency habitability system credited (VES Credited)	
- Main control room activity level at which the emergency habitability system actuation is actuated (Ci/m^3 of dose equivalent I-131)	2.0 E-07
- Response time to actuate VES based on radiation monitor response time and VBS isolation (sec)	200
- Interval with operation of the emergency habitability system	
• Flow from compressed air bottles of the emergency habitability system (cfm)	60
• Unfiltered inleakage via ingress/egress (scfm)	5
• Unfiltered inleakage from other sources (scfm)	10
• Recirculation flow through filters (scfm)	600
• Filter efficiency (%)	
• Elemental iodine	90
• Organic iodine	90
• Particulates	99
- Time at which the compressed air supply of the emergency habitability system is depleted (hr)	72
- After depletion of emergency habitability system bottled air supply (>72 hr)	
• Air intake flow (cfm)	1900
• Intake flow filter efficiency (%)	Not applicable
• Recirculation flow (cfm)	Not applicable
- Time at which the compressed air supply is restored and emergency habitability system returns to operation (hr)	168

PTN DEP 6.4-1

TABLE 15.6.5-2R (SHEET 3 OF 3)
ASSUMPTIONS AND PARAMETERS USED IN CALCULATING RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Control room with credit for continued operation of HVAC (VBS Supplemental Filtration Mode Credited)	
- Time to switch from normal operation to the supplemental air filtration mode (sec)	265
- Unfiltered air inleakage (cfm)	25
- Filtered air intake flow (cfm)	860
- Filtered air recirculation flow (cfm)	2740
- Filter efficiency (%)	
• Elemental iodine	90
• Organic iodine	90
• Particulates	99
Miscellaneous assumptions and parameters	
- Offsite power	Not applicable
- Atmospheric dispersion factors (offsite)	See Table 15A-5
- Nuclide dose conversion factors	See Table 15A-4
- Nuclide decay constants	See Table 15A-4
- Offsite breathing rate (m^3/sec)	
0 - 8 hr	3.5 E-04
8 - 24 hr	1.8 E-04
24 - 720 hr	2.3 E-04

PTN DEP 6.4-1

TABLE 15.6.5-3R
RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT WITH CORE MELT

	TEDE Dose (rem)
Exclusion zone boundary dose (1.3 - 3.3 hr)[1]	23.5
Low population zone boundary dose (0 - 30 days)	22.2
Main control room dose (emergency habitability system in operation)	
- Airborne activity entering the main control room	3.70
- Direct radiation from adjacent structures, including sky shine	0.30
- Filter shine	0.32
- Spent fuel pooling boiling	0.01
- Total	4.33
Main control room dose (normal HVAC operating in the supplemental filtration mode)	
- Airborne activity entering the main control room	4.50
- Direct radiation from adjacent structures, including sky shine	0.30
- Filter shine	0.03
- Spent fuel pooling boiling	0.01
- Total	4.84

Note:
1. This is the 2-hour period having the highest dose.

15.7 RADIOACTIVE RELEASE FROM A SUBSYSTEM OR COMPONENT

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15.7.4.5 Offsite Doses

Revise the first sentence of the first paragraph of DCD Subsection 15.7.4.5 to read as follows:

PTN DEP 6.4-1 Using the assumptions from Table 15.7-1R, the calculated doses from the initial releases are determined to be 2.8 rem TEDE at the site boundary and 1.2 rem TEDE at the low population zone outer boundary.

15.7.6 COMBINED LICENSE INFORMATION

PTN COL 15.7-1 This COL Item is addressed in Subsection 2.4.13.

PTN DEP 6.4-1

TABLE 15.7-1R
ASSUMPTIONS USED TO DETERMINE FUEL HANDLING ACCIDENT RADIOLOGICAL CONSEQUENCES

Source term assumptions	
- Core power (MWt)	3434[1]
- Decay time (hr)	48
Core source term after 48 hours decay (Ci)	
I-130	1.28 E+05
I-131	8.18 E+07
I-132	9.10 E+07
I-133	4.06 E+07
I-135	1.17 E+06
Kr-85m	1.52 E+04
Kr-85	1.07 E+06
Kr-88	5.45 E+02
Xe-131m	1.02 E+06
Xe-133m	4.47 E+06
Xe-133	1.70 E+08
Xe-135m	1.91 E+05
Xe-135	1.04 E+07
Number of fuel assemblies in core	157
Amount of fuel damage	One assembly
Maximum rod radial peaking factor	1.75
Percentage of fission products in gap	
I-131	8
Other iodines	5
Kr-85	10
Other noble gases	5
Pool decontamination factor for iodine	200
Activity release period (hr)	2
Atmospheric dispersion factors	See Table 15A-5 in Appendix 15A
Breathing rates (m^3/sec)	3.5 E-4
Nuclide data	See Appendix 15A

Note:
1. The main feedwater flow measurement supports a 1-percent power uncertainty.

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

APPENDIX 15A EVALUATION MODELS AND PARAMETERS FOR ANALYSIS OF RADIOLOGICAL CONSEQUENCES OF ACCIDENTS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15A.3.1.2 Secondary Coolant Source Term

Revise the first sentence of the first paragraph of DCD Subsection 15A.3.1.2 to read as follows:

PTN DEP 6.4-1 The secondary coolant source term used in the radiological consequences analyses is conservatively assumed to be 1 percent of the primary coolant equilibrium source term.

15A.3.3 ATMOSPHERIC DISPERSION FACTORS

Replace the third paragraph in DCD Subsection 15A.3.3 with the following:

PTN COL 2.3-4 Site-specific X/Q values provided in Subsection 2.3.4 are bounded by the values given in DCD Table 15A-5 and Table 15A-6.

APPENDIX 15B REMOVAL OF AIRBORNE ACTIVITY FROM THE CONTAINMENT ATMOSPHERE FOLLOWING A LOCA

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

15B.1 ELEMENTAL IODINE REMOVAL

Revise the second full paragraph of DCD Subsection 15B.1 to read as follows:

PTN DEP 6.4-1 The available deposition surface is 251,000 ft^2, and the containment building net free volume is 2.06×10^6 ft^3. From these inputs, the elemental iodine removal coefficient is 1.9 hr^{-1}.

CHAPTER 16: TECHNICAL SPECIFICATIONS
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CHAPTER 16 TECHNICAL SPECIFICATIONS

16.1 TECHNICAL SPECIFICATIONS

Subsections 16.1.1 and 16.1.2 of the DCD are incorporated by reference with no departures or supplements. The generic technical specifications and bases in Chapter 16 of the DCD are not considered Tier 2 information; therefore they are not incorporated by reference within this FSAR. However, the generic technical specifications and bases provided with Chapter 16 of the DCD are incorporated by reference into the plant-specific technical specifications provided in Part 4 of this COL Application. In addition, a full information set of the plant-specific technical specifications and bases are provided in Part 4 of this COL Application.

16.1.1 INTRODUCTION TO TECHNICAL SPECIFICATIONS

Combined License Information

PTN COL 16.1-1 This COL Item (i.e., information addressing each of the remaining brackets [ ] in the AP1000 generic technical specifications) is addressed in Part 4 of the COL Application.

16.2 DESIGN RELIABILITY ASSURANCE PROGRAM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

16.3 INVESTMENT PROTECTION

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

16.3.1 INVESTMENT PROTECTION SHORT-TERM AVAILABILITY CONTROLS

Add the following paragraph after the bulleted items at the end of the second paragraph of DCD Subsection 16.3.1:

STD COL 16.3-1 Station procedures govern and control the operability of investment protection systems, structures, and components, in accordance with Table 16.3-2 of the DCD, and provide the operating staff with instruction for implementing required actions when operability requirements are not met. Procedure development is addressed in FSAR Section 13.5.

16.3.2 COMBINED LICENSE INFORMATION

STD COL 16.3-1 This COL Item is addressed in Subsection 16.3.1.

CHAPTER 17: QUALITY ASSURANCE
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CHAPTER 17 QUALITY ASSURANCE

17.1 QUALITY ASSURANCE DURING THE DESIGN AND CONSTRUCTION PHASES

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

PTN COL 17.5-1 FPL is responsible for the establishment and execution of quality assurance program requirements during the design, construction, and operations phases of Turkey Point Units 6 & 7. FPL may delegate the work of establishing and executing the quality assurance program, or any parts thereof, but retains responsibility for the quality assurance program.

The COL Application development through and including COL issuance was conducted in accordance with the requirements of an FPL-approved quality assurance program, which meets the requirements of 10 CFR Part 50 Appendix B and complies with the applicable criteria of ASME NQA-1, 1994. The application of these requirements to the COL Application development activities is defined in the FPL Fleet QA Topical Report, FPL-1.

COL Application development and site characterization services were procured in accordance with the existing FPL Quality Assurance Program requirements from Bechtel Power Corporation. Bechtel Power Corporation performed their assigned tasks in accordance with the requirements of their own quality assurance program that was reviewed and approved by FPL for conduct of safety-related work. The process of collection, review, and analysis of specific data for site characterization was performed under the Bechtel Nuclear Quality Assurance Manual (NQAM) as described in the Bechtel Turkey Point COL Project Quality Assurance Program Plan (QAPP).

FPL maintains oversight of the contractor activities performed in support of the COL Application development contract in accordance with its existing 10 CFR Part 50 Appendix B program as described in the FPL Quality Assurance Topical Report, FPL-1. FPL oversight of the COL development activities is provided through conducting quality assurance audits and surveillances of the contractor activities and processes, and by direct participation in COL development activities. FPL provided site-specific applicant input and review of COL Application content.

Upon issuance of a COL, the FPL New Nuclear Projects Quality Assurance Program Description FPL-2 (QAPD) described in Section 17.5 will be used for activities related to the remaining portion of the design, construction, and operational phases of the new nuclear facilities.

The Turkey Point Units 6 & 7 safety-related design activities conducted under the program described in Section 17.1 are performed in conformance with RG 1.28, Revision 3. This is the only identified applicable quality assurance related Regulatory Guide for the program in place prior to COL receipt.

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

This section of the referenced DCD is incorporated by reference with no departures or supplements.

17.3 QUALITY ASSURANCE DURING DESIGN, PROCUREMENT, FABRICATION, INSPECTION, AND/OR TESTING OF NUCLEAR POWER PLANT ITEMS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

17.4 DESIGN RELIABILITY ASSURANCE PROGRAM

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

STD SUP 17.4-1 The quality assurance requirements for non-safety related SSCs within the scope of D-RAP is in accordance with the Quality Assurance Program Description (QAPD), Part III.

STD DEP 1.1-1

17.5 QUALITY ASSURANCE PROGRAM DESCRIPTION — NEW LICENSE APPLICANTS

PTN COL 17.5-1
STD COL 17.5-2
STD COL 17.5-4
STD COL 17.5-8

The quality assurance program in place during the design, construction, and operations phases is described in the QAPD, which is maintained as a separate document. The QAPD is incorporated by reference (see Table 1.6-201). This QAPD is based on NEI 06-14A, “Quality Assurance Program Description” (Reference 203).

Conformance statements for QA-related Regulatory Guides (including Regulatory Guides 1.28, 1.30, 1.33, 1.38, 1.39, 1.94, and 1.116) are provided in Appendix 1AA. While many Regulatory Guide positions can be identified as applicable to the scope of work identified and addressed by the DCD and others can be identified as applicable to the scope of work identified and addressed by the COLA, some QA guidance related positions could be accomplished by either scope of work and thus be addressed in either the DCD or the COLA. These positions are primarily dependent on who performs the work. The DCD conformance statement indicates an exception to apply NQA-1. The COLA identifies an exception to apply NQA-1. Per DCD Section 17.3, WEC work performed up to March 15, 2007 applied a 1991 version of the standard. A 1994 version of the standard is applied for work performed after that date by WEC. If the work is performed under the applicant’s COL program, the 1994 version of NQA-1 identified in the COLA QAPD is applied. Thus, DCD scope (identified in DCD Appendix 1A) and “remaining scope” differentiate the application of the guidance identified in these Regulatory Guides.

PTN COL 17.5-1

The QAPD is the Units 6 & 7 Quality Assurance Program Description.

PTN COL 17.5-1
STD COL 17.5-2
STD COL 17.5-4
STD COL 17.5-8

Table 13.4-201 provides milestones for operational quality assurance program implementation.

PTN COL 17.5-1

The quality assurance program in place before implementation of the QAPD is described in Section 17.1.

STD DEP 1.1-1

17.6 MAINTENANCE RULE PROGRAM

STD SUP 17.6-1
STD COL 3.8-5

This section incorporates by reference NEI 07-02A, “Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52,” (Reference 205) with the following supplemental information. See Table 1.6-201.

Table 13.4-201 provides milestones for maintenance rule program implementation.

The text of the template provided in NEI 07-02A is generically numbered as “17.X.” When the template is incorporated by reference into this FSAR, section numbering is changed from “17.X” to “17.6.”

STD SUP 17.6-1

Descriptions of the programs listed in Subsection 17.6.3 of NEI 07-02A are provided in the following FSAR chapters/sections:

The maintenance rule program (Section 17.6)

The quality assurance program (Section 17.5)

Inservice inspection program (Sections 5.2 and 6.6)

Inservice testing program (Section 3.9)

The technical specifications surveillance test program (Chapter 16)

STD SUP 17.6-2

Condition monitoring of underground or inaccessible cables is incorporated into the maintenance rule program. The cable condition monitoring program incorporates lessons learned from industry operating experience, addresses regulatory guidance, and utilizes information from detailed design and procurement documents to determine the appropriate inspections, tests and monitoring criteria for underground and inaccessible cables within the scope of the maintenance rule (i.e., 10 CFR 50.65). The program takes into consideration Generic Letter 2007-01.

STD DEP 1.1-1

17.7 COMBINED LICENSE INFORMATION ITEMS

Section 17.5 of the referenced DCD is incorporated by reference with the following departures and/or supplements.

PTN COL 17.5-1 This COL Item is addressed in Sections 17.1 and 17.5.

STD COL 17.5-2 This COL Item is addressed in Section 17.5.

STD COL 17.5-4 This COL Item is addressed in Section 17.5.

STD COL 17.5-8 This COL Item is addressed in Section 17.5.

STD DEP 1.1-1

17.8 REFERENCES

Section 17.6 of the referenced DCD is incorporated by reference with the following departures and/or supplements.

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201. Not Used.

202. Not Used.

203. Nuclear Energy Institute, *Quality Assurance Program Description*, NEI 06-14A, Rev. 7, August 10, 2010.

204. Not Used.

205. Nuclear Energy Institute, *Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52*, NEI 07-02A, Rev. 0 (Corrected), November 2010.

CHAPTER 18: HUMAN FACTORS ENGINEERING
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CHAPTER 18 HUMAN FACTORS ENGINEERING

18.1 OVERVIEW

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.2 HUMAN FACTORS ENGINEERING PROGRAM MANAGEMENT

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

18.2.1.3 Applicable Facilities

Add the following information at the end of DCD Subsection 18.2.1.3.

PTN COL 18.2-2 The EOF and TSC communication strategies, as well as the EOF and TSC Human Factors attributes, are described in the Emergency Plan.

18.2.6 COMBINED LICENSE INFORMATION

18.2.6.2 Emergency Operations Facility

PTN COL 18.2-2 This COL item is addressed in Subsection 18.2.1.3.

18.3 OPERATING EXPERIENCE REVIEW

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.4 FUNCTIONAL REQUIREMENTS ANALYSIS AND ALLOCATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.5 AP1000 TASK ANALYSIS IMPLEMENTATION PLAN

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.6 STAFFING

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

STD COL 18.6-1 Replace the DCD paragraph in Section 18.6 with the following information.

Table 13.1-201 contains the estimated staffing levels for those categories of personnel that are addressed by the Human Factors Engineering program per NUREG-0711, “Human Factors Engineering Program Review Model” (Reference 201), as follows:

- Licensed operators
- Shift Supervisors
- Non-licensed operators
- Shift technical advisors
- Instrumentation and control technicians
- Mechanical maintenance technicians
- Electrical maintenance technicians
- Radiation protection technicians
- Chemistry technicians
- Engineering support

The minimum level of staffing for control room personnel who directly monitor and control the plant is stated in Table 13.1-202 and meets the requirements of 10 CFR 50.54(m). Information about the staffing levels of security personnel is contained in the separately submitted physical security plan.

Qualification requirements of plant personnel listed above are discussed in Subsections 13.1.1.4, Qualifications of Technical Support Personnel, and 13.1.3, Qualification Requirements of Nuclear Plant Personnel, and, for security personnel, in the physical security plan.

The baseline level of staffing for the categories of personnel discussed above is derived from experience in current operating nuclear power plants. The number of personnel in operating plants has evolved over many years to a level that is safe and efficient and provides adequate personnel to operate the plant under all conditions, including abnormal and emergency, meets regulatory requirements, and supports individual training and personal needs.

Iterative adjustments are implemented to the level of staffing, as necessary, based on findings and input from periodic reviews and staffing analysis. Input to this analysis includes information derived from the other elements of the human factors engineering program, particularly operating experience review, functional requirements analysis and function allocation, task analysis, human reliability analysis, human-system interface design, procedure development, and training program development.

In addition to the regulatory requirements referenced, input to the analyses and the level of staffing is provided by WCAP-14694, “Designer’s Input to Determination of the AP600 Main Control Room Staffing Level” (DCD Section 18.6, Reference 1), AP1000 Combined License Technical Report APP-GW-GLR-010, “AP1000 Main Control Room Staff Roles and Responsibilities” (Reference 202), and EPRI Technical Report 1011717, “Program on Technology Innovation: Staff Optimization Scoping Study for New Nuclear Power Plants” (Reference 203).

18.6.1 COMBINED LICENSE INFORMATION ITEM

STD COL 18.6-1 This COL Item is addressed in Section 18.6.

18.6.2 REFERENCES

201. U.S. Nuclear Regulatory Commission, *Human Factors Engineering Program Review Model*, NUREG-0711, Rev. 2, February 2004.

202. Westinghouse, *AP1000 Main Control Room Staff Roles and Responsibilities*, APP-GW-GLR-010, Rev. 2, June 2007.

203. Electric Power Research Institute, *Program on Technology Innovation: Staff Optimization Scoping Study for New Nuclear Power Plants*, EPRI Report TR-1011717, Final Report, August 2005.

18.7 INTEGRATION OF HUMAN RELIABILITY ANALYSIS WITH HUMAN FACTORS ENGINEERING

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.8 HUMAN SYSTEM INTERFACE DESIGN

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

18.8.3.5 Technical Support Center Mission and Major Tasks

Replace the last sentence of the first paragraph with the following:

PTN DEP 18.8-2 The Technical Support Center (TSC) location is described in the Emergency Plan.

18.8.3.6 Operations Support Center Mission and Major Tasks

Replace the last sentence of the first paragraph with the following:

PTN DEP 18.8-1 The Operations Support Center (OSC) location is described in the Emergency Plan.

18.9 PROCEDURE DEVELOPMENT

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.10 TRAINING PROGRAM DEVELOPMENT

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

Add the following paragraphs at the end of DCD Subsection 18.10:

STD COL 18.10-1 Information regarding training program development is located in Section 13.2, Training. The training organization and roles and responsibilities of training personnel are discussed in Section 13.1, Organizational Structure of Applicant.

18.10.1 COMBINED LICENSE INFORMATION

STD COL 18.10-1 This COL Item is addressed in Section 18.10, 13.1, and 13.2.

18.11 HUMAN FACTORS ENGINEERING VERIFICATION AND VALIDATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.12 INVENTORY

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.13 DESIGN IMPLEMENTATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

18.14 HUMAN PERFORMANCE MONITORING

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

Replace the DCD paragraph with the following text.

STD COL 18.14-1 Human performance monitoring applies after the plant is placed in operation. The human performance monitoring process implements the guidance and methods as described in DCD Section 18.14 Reference 1.

The human performance monitoring process provides reasonable assurance that:

- The design can be effectively used by personnel, including within the control room and between the control room and local control stations and support centers.
- Changes made to the human system interface(s), procedures, and training do not have adverse effects on personnel performance, (e.g., a change does not interfere with previously trained skills).
- Human actions can be accomplished within time and performance criteria.
- The acceptable level of performance established during the design integrated system validation is maintained.

The human performance monitoring process is structured such that:

- Human actions are monitored commensurate with their safety importance.
- Feedback of information and corrective actions are accomplished in a timely manner.
- Degradation in performance can be detected and corrected before plant safety is compromised (e.g., by use of the plant simulator during training exercises).

The human performance monitoring process for risk-informed changes is integrated into the corrective action program, training program and other programs as appropriate. Identified human performance conditions/issues are evaluated for human factors engineering applicability.

Human factors engineering conditions are assigned specific human factors cause determination codes, trended for indications of degraded performance or potential human performance failures and have specific corrective actions identified.

The cause investigation:

- Identifies the cause of the failure or degraded performance to the extent that corrective action can be taken consistent with the corrective action program requirements.
- Addresses failure significance which includes the circumstances surrounding the failure or degraded performance, the characteristics of the failure, and whether the failure is isolated or has generic or common cause implications.
- Identifies and establishes corrective actions necessary to preclude the recurrence of unacceptable failures or degraded performance in the case of a significant condition adverse to quality.

When appropriate, design changes are integrated into training exercises to monitor for degradation in performance and allow for early detection and corrective actions before plant safety is challenged (e.g., by use of the plant simulator during training exercises).

Plant or personnel performance under actual design conditions may not be readily measurable. When actual conditions cannot be simulated, monitored, or measured, the available information that most closely approximates performance data in actual conditions should be used.

Monitoring strategies for human performance trending after the implementation of design changes are capable of demonstrating that performance is consistent with that assumed in the various analyses conducted to justify the change.

Risk-informed changes are screened commensurate with their safety importance to determine if the change requires monitoring of actions. For changes which require monitoring, the appropriate monitoring requirements are determined and implemented in the training program or other program as appropriate.

CHAPTER 19: PROBABILISTIC RISK ASSESSMENT
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CHAPTER 19 PROBABILISTIC RISK ASSESSMENT

19.1 INTRODUCTION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.2 INTERNAL INITIATING EVENTS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.3 MODELING OF SPECIAL INITIATORS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.4 EVENT TREE MODELS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.5 SUPPORT SYSTEMS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.6 SUCCESS CRITERIA ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.7 FAULT TREE GUIDELINES

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.8 PASSIVE CORE COOLING SYSTEM — PASSIVE RESIDUAL HEAT REMOVAL

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.9 PASSIVE CORE COOLING SYSTEM — CORE MAKEUP TANKS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.10 PASSIVE CORE COOLING SYSTEM — ACCUMULATOR

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.11 PASSIVE CORE COOLING SYSTEM — AUTOMATIC DEPRESSURIZATION SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.12 PASSIVE CORE COOLING SYSTEM — IN-CONTAINMENT REFUELING WATER STORAGE TANK

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.13 PASSIVE CONTAINMENT COOLING

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.14 MAIN AND STARTUP FEEDWATER SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.15 CHEMICAL AND VOLUME CONTROL SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.16 CONTAINMENT HYDROGEN CONTROL SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.17 NORMAL RESIDUAL HEAT REMOVAL SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.18 COMPONENT COOLING WATER SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.19 SERVICE WATER SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.20 CENTRAL CHILLED WATER SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.21 AC POWER SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.22 CLASS 1E DC & UPS SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.23 NON-CLASS 1E DC & UPS SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.24 CONTAINMENT ISOLATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.25 COMPRESSED AND INSTRUMENT AIR SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.26 PROTECTION AND SAFETY MONITORING SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.27 DIVERSE ACTUATION SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.28 PLANT CONTROL SYSTEM

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.29 COMMON CAUSE ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.30 HUMAN RELIABILITY ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.31 OTHER EVENT TREE NODE PROBABILITIES

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.32 DATA ANALYSIS AND MASTER DATA BANK

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.33 FAULT TREE AND CORE DAMAGE QUANTIFICATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.34 SEVERE ACCIDENT PHENOMENA TREATMENT

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.35 CONTAINMENT EVENT TREE ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.36 REACTOR COOLANT SYSTEM DEPRESSURIZATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.37 CONTAINMENT ISOLATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.38 REACTOR VESSEL REFLOODING

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.39 IN-VESSEL RETENTION OF MOLTEN CORE DEBRIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.40 PASSIVE CONTAINMENT COOLING

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.41 HYDROGEN MIXING AND COMBUSTION ANALYSIS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

19.41.7 DIFFUSION FLAME ANALYSIS

Revise the last two paragraphs of DCD Subsection 19.41.7 to read as follows:

PTN DEP 6.2-1 In the event that ADS stage 4 fails to adequately direct hydrogen away from confined compartments, the compartment vents are designed to release the hydrogen at locations where it burns, but does not challenge the containment shell integrity.

Vents from the PXS and CVS compartments to the CMT room are located away from the containment shell and containment penetrations. Access hatches to the subcompartments that are near the containment shell are covered and secured closed such that they will not open as a result of a pipe break inside the compartment. Therefore, hydrogen releases to the CMT room from the subcompartments have been shown to not challenge the containment integrity.

19.42 CONDITIONAL CONTAINMENT FAILURE PROBABILITY DISTRIBUTION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.43 RELEASE FREQUENCY QUANTIFICATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.44 MAAP4.0 CODE DESCRIPTION AND AP1000 MODELING

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.45 FISSION PRODUCT SOURCE TERMS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.46 NOT USED

This section was not required for DCD and is not used by DCD and FSAR.

19.47 NOT USED

This section was not required for DCD and is not used by DCD and FSAR.

19.48 NOT USED

This section was not required for DCD and is not used by DCD and FSAR.

19.49 OFFSITE DOSE EVALUATION

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.50 IMPORTANCE AND SENSITIVITY ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.51 UNCERTAINTY ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.52 NOT USED

This section was not required for DCD and is not used by DCD and FSAR.

19.53 NOT USED

This section was not required for DCD and is not used by DCD and FSAR.

19.54 LOW POWER AND SHUTDOWN PRA ASSESSMENT

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.55 SEISMIC MARGIN ANALYSIS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

19.55.6.3 Site Specific Seismic Margin Analysis

The Seismic Margin Assessment outlined in this section is in accordance with the Interim Staff Guidance DC/COL-ISG-020.

The Seismic Margin Assessment conducted for Turkey Point Units 6 & 7 follows the DC/COL-ISG-020 category where site-specific updates on the DC PRA-based seismic margin evaluation are considered for the COL application.

PTN COL 19.59.10-6

The Turkey Point site seismic demand, based on the site Ground Motion Response Spectra (GMRS), as described in Subsection 3.7.1.1, is enveloped by the AP1000 CSDRS as defined by Tier 1 criteria for SSE.

For site-specific conditions relating to soil- or rock-related failure modes (i.e., slope stability, liquefaction, and dynamic bearing capacity), the recommended seismic margin in accordance with DC/COL-ISG-020 is 1.67 x GMRS. The GMRS PGA is 0.0579g (Table 2.5.2-228), corresponding to a recommended seismic margin of 0.0967g.

As discussed in Subsection 2.5.5.5, the permanent slopes are directed away from the power block and have a maximum grade of 0.5 percent. Thus, significant movement or failure of these slopes would not adversely affect the safety of the nuclear power plant facilities. The mechanically stabilized earth (MSE) walls on the perimeter of the plant area are further than 500 feet away from the Seismic Category I structures, and their failure would not impact the safety-related structures. Therefore, the Seismic Margin Assessment is not conducted for these walls or any slopes.

The seismic input to the liquefaction and dynamic bearing pressures is 0.1g, which is a scaled up value which corresponds to the minimum PGA required for the safe shutdown earthquake (SSE) per 10 CFR Part 50 Appendix S.

The results of the liquefaction analyses are provided in Figures 2.5.4-238, 2.5.4-250, and 2.5.4-251.

As discussed in Subsection 2.5.4.8.4, almost all (99.8 percent) of the factors of safety against liquefaction calculated based on shear wave velocity are above 1.4. Two locations have an intermediate factor of safety (1.1 < FOS < 1.4). There is one location at which the calculated factor of safety is low (FOS < 1.1). If the FOS is calculated as an average over adjacent measured points, it is equal to 2.40 (among the central point and one adjacent point on each side [top and bottom] for a total of 3 points), 2.93 (5 points), and 3.16 (7 points); this shows that the low value of 1.07 is a localized exception, and does not represent a weak zone.

As discussed in Subsection 2.5.4.8.2, the SPT liquefaction analysis is based on the summation of the 2nd and 3rd blow counts (SPT N) and the summation of the 3rd and 4th blow counts from the supplemental investigation. For the more likely conditions of the soil in situ, represented by the summation of the 3rd and 4th blow counts, 70 points out of 79 points are directly classified as non-liquefiable. There is only one location at which the calculated factor of safety is low (FOS < 1.1), which corresponds to the transition between the Fort Thompson and Upper Tamiami formations.

As discussed in Subsection 2.5.4.8.3, the factor of safety against liquefaction calculated based on CPT is consistently higher than 1.1 across the full depth of testing at the site.

Based on shear wave velocity, SPT, and CPT data, there is no potential for liquefaction for the Turkey Point Units 6 & 7 power block area with the input PGA of 0.1g.

In addition, corrections for the effects of aging are ignored. Reference 2.5.4-219 states that sediments deposited within the past few thousand years are generally much more susceptible to liquefaction than older Holocene sediments; it states that Pleistocene sediments are even more resistant, and regards pre-Pleistocene sediments as generally immune to liquefaction. The Upper Tamiami and Lower Tamiami are Pliocene formations, and the Peace River is a Miocene-Pliocene formation (Subsection 2.5.1.1.1.2.1.1). These deposits are thus substantially older than the range of ages considered in Reference 2.5.4-219 as being susceptible to liquefaction.

The results of the dynamic bearing capacity analysis are provided in Table 2.5.4-217. The minimum allowable dynamic bearing capacity is 41 ksf; this is acceptable according to the 35 ksf bearing demand required by the DCD.

The PGA used in the liquefaction and dynamic bearing capacity analyses, 0.1g, is greater than the GMRS (0.0579g) by a ratio of 1.73 (greater than 1.67). In accordance with DC/COL-ISG-020, the recommended seismic margin is 0.0967g and the analysis indicates the available seismic margin for the liquefaction and dynamic bearing capacity is greater than 0.1g. Therefore, the site-specific soil effects on the seismic fragility of the pertinent SSC and the plant-level high confidence low probability of failure (HCLPF) are deemed not to be controlling and are screened out.

Since the criteria in DC/COL-ISG-020 are met, the Seismic Margin Assessment analysis documented in DCD Section 19.55 is applicable to the Turkey Point Units 6 & 7 site.

The nuclear island for Turkey Point Units 6 & 7 is founded on approximately 20 feet of concrete fill underlain by about 80 feet of bedrock. For seismic stability of the nuclear island, it was demonstrated that the Turkey Point Units 6 & 7 nuclear island margins against sliding and overturning were greater than the limiting nuclear island margins calculated for the standard AP1000 design cases. For seismic stability, the Seismic Margin Assessment analysis documented in DCD Section 19.55 is applicable to the Turkey Point Units 6 & 7 site.

19.56 PRA INTERNAL FLOODING ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.57 INTERNAL FIRE ANALYSIS

This section of the referenced DCD is incorporated by reference with no departures or supplements.

19.58 WINDS, FLOODS, AND OTHER EXTERNAL EVENTS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

19.58.1 INTRODUCTION

Add the following text to the end of DCD Subsection 19.58.1:

PTN COL 19.59.10-2

A summary of the risk evaluations of the various external events is provided in Table 19.58-202.

19.58.2.1 Severe Winds and Tornadoes

Replace the text of DCD Subsection 19.58.2.1 with the following:

PTN DEP 19.58-1

The overall methodology recommended by NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities" for analyzing plant risk due to high winds and tornadoes is a progressive screening approach. This approach is modified to consider hazards occurrence, likelihood and risk.

High winds (including tornadoes) can affect plant structures in at least two ways: (1) If wind forces exceed the load capacity of a building or other external facility, the walls or framing might collapse or the structure might overturn from the excessive loading; and (2) If the wind is strong enough, as in a tornado or hurricane, it may be capable of lifting materials and thrusting them as missiles against the plant structures that house safety related equipment. Critical components or other contents of plant structures not designed to resist missile penetration might be damaged and lose their ability to function.

NUREG-1407, Section 2.3, High Winds and Tornados, states that "For plants designed against NRC's current criteria, these events pose no significant threat of a severe accident because the current design criteria for wind are dominated by tornadoes having an annual frequency of exceedance of about 10^{-7}." This is interpreted to mean that external events with an annual frequency less than about 1.0E–07 may be screened from further consideration and events with an annual

frequency greater than 1.0E–07 may require further evaluation. However, the NUREG-1407 screening criterion was developed for current operating plants.

If the external event category cannot be screened out on the basis of its annual frequency, a second screening criterion based on the annual core damage frequency (CDF) associated with that external event category can be used. If the CDF can be demonstrated to not exceed 1.0E–08, the external event category can be screened out.

The AP1000 design basis wind speed is 300 mph, as described in DCD Chapter 2. This value is assumed to be the maximum wind speed that will not challenge the safety related structures. The AP1000 operating basis wind speed is 145 mph, also described in DCD Chapter 2. This value is assumed to be the maximum wind speed that will not challenge the non-safety related structures.

The structures protecting safety related features of the AP1000 are designed for extreme winds and missiles associated with these winds. As long as the external event wind speeds are less than the design basis value, the safety features of the AP1000 will be unaffected. If the winds exceed the design values, then the integrity of the safety related structures may be compromised.

The structures protecting non-safety related features of the AP1000 are designed according to the Uniform Building Code that provides some level of protection against seismic and high wind events. As long as the external event winds are less than the operating basis wind speed, the non-safety features of the AP1000 will be unaffected. If the winds exceed the operating basis values, then the integrity of the non-safety related structures may be compromised.

Per the Enhanced Fujita (EF) Scale for Tornadoes, no tornadoes are expected to have wind speeds that exceed 300 mph; however, EF3, EF4, and EF5 tornado wind speeds do exceed the operating basis wind speed. Per the Saffir-Simpson Scale for Hurricanes, no hurricanes are expected to reach 300 mph winds; however, Category 3, Category 4, and Category 5 hurricane winds may exceed the operating basis wind speed.

The evaluation of the high winds hazard uses the two screening criteria established from the previous description. The first criterion is that if the high wind event category annual frequency does not exceed 1.0E–07, the event category can be screened out from the requirement to perform further analysis. If the first criterion is not met, the second criterion is that if the annual CDF for the event category is assessed to not exceed 1.0E–08, the event category can be screened

out. As can be seen from Table 19.58-202, the annual frequency of tornado and hurricane events exceeds 1.0E–07 per year. Therefore, the screening CDF is calculated for high winds to determine if detailed analysis is required.

Risk assessment studies for nuclear power plants typically assume that high wind events cause a Loss of Offsite Power (LOSP) because the site switchyard is not designed to withstand hurricane and tornado wind speeds. For wind speeds greater than the operating basis wind speed, additional structures, systems and components (SSC) may also be damaged. Two analyses were performed to calculate the conditional core damage probability (CCDP) for two plant states resulting from high wind events and are presented in Reference 201. One analysis considered only a LOSP with all plant systems available and the other analysis considered a LOSP along with failure of all standby non-safety systems. These two plant states are defined by the maximum wind speed experienced during the event being either (1) less than or equal to the plant operating basis wind speed or (2) greater than the plant operating basis wind speed. The CCDP for the case of maximum wind speed less than or equal to the operating basis wind speed is 9.81E–09 and the CCDP for the case of maximum wind speed greater than the operating basis wind speed is 5.85E–08.

Risk (CDF) due to the event can then be estimated using the equation:

$$CDF = IEF * CCDP$$

where IEF is the initiating event frequency. If this evaluation indicates an acceptably small contribution to risk (e.g., CDF not greater than about 1.0E–08 events/yr) then the progressive screening is complete and a detailed PRA is not required.

Three studies (Case 1, Case 2, and Case 3) are presented to evaluate CDF for the high wind events for Units 6 & 7. These studies utilize the process described in Reference 201 along with event frequencies specifically for Units 6 & 7.

In the Case 1 study, plant response is a LOSP induced by high wind, with all plant equipment available. All tornados and hurricanes are considered in this Case 1 as they may challenge the switchyard. Extratropical cyclones are normal storms and thunderstorms that typically have wind speeds below the operating basis, but they can, however, regain winds of hurricane or tropical storm force and are also included in the Case 1 analysis, assuming that they cause a LOSP. In Case 1, the CCDP of 9.81E–09 is applied to all storms.

The Case 2 study was performed by modifying Case 1 to apply the CCDP of 5.85E–08 to events that could expose the plant to wind speed greater than the operating basis wind speed.

Category 2 and lower hurricanes and EF0, EF1, and EF2 tornadoes have a CCDP of 9.81E–09 applied.

The range of sustained wind speed for Category 3 hurricanes is 111 mph to 130 mph. Although this range of wind speed is less than the operating basis wind speed, Category 3 hurricanes can have wind gusts that do exceed the operating basis wind speed. Hurricanes labeled as “Category 3" had a maximum wind speed that was within the Category 3 range but some storms were below the Category 3 level for some of the time. To more appropriately represent the effect of Category 3 hurricanes in this Case 2 study, the Category 3 hurricane data for Units 6 & 7 was subdivided on the basis of the fraction of time, while within the 100 nautical mile radius of the site, that the storms were at or below Category 3. If the storm intensity decayed below the Category 3 level, then even wind gusts from the storm would not generate wind speeds that exceed operating basis wind speed and for this fraction of the time that Category 3 hurricanes resided in the 100 nautical mile radius of interest, they would not pose a threat to AP1000 non-safety systems. For the 13 documented Category 3 hurricanes, there are a total of 42 data points reported. Of these 42 data points, 13 indicate that the storm was below Category 3 hurricane intensity. On this basis, 13/42, or 31 percent of the Category 3 event frequency will have a CCDP of 9.81E–09 applied and 69 percent of the Category 3 event frequency will have a CCDP of 5.85E–08 applied.

Category 4 and higher hurricanes and EF3, EF4, and EF5 tornados have a CCDP of 5.85E–08 applied.

Case 3 is a conservative study where all high wind events are evaluated as a LOSP with failure of all non-safety systems. The CCDP of 5.85E–08 was applied to all events. This case was created to represent the risk to the plant if the non-safety structures were not designed to any code. This is a very conservative sensitivity study because all of the structures are designed to the Uniform Building Code.

Results of the calculation of CDF, using the appropriate value of CCDP and the tornado and hurricane occurrence frequencies for Units 6 & 7, are shown in Table 19.58-202. As can be seen from Table 19.58-201, both Cases 1 and 2 have CDF not greater than 1.0E–08 per year. Case 3 has a CDF slightly higher than 1.0E–08 per year.

Case 2 is the "base case" and is considered to be the representative conservative model for high winds, with Case 1 and Case 3 being treated as sensitivity studies. Case 3 is very conservative in that it assumes total failure of the standby non-safety systems (CVS, RNS, SFW, automatic DAS, and Diesel Generators) for all high wind events. Non-safety structures are designed to the Uniform Building Code that offers a degree of robustness such that the above failures are considered extreme and conservative. Therefore, while the total Case 3 CDF does fall slightly above the 1.0E–08 per year CDF screening criterion, the results are considered very conservative for the above reasons. The CDF for Case 2 is 1.0E–08 and, consequently, further detailed PRA is not necessary for the Units 6 & 7 High Winds and Tornados analysis.

19.58.2.3.1 Aviation Accidents

Replace the text of DCD Subsection 19.58.2.3.1 with the following:

PTN COL 19.59.10-2 A conservative analysis was performed to evaluate the risk to Turkey Point Units 6 & 7 due to aviation accidents. The aviation accident hazard evaluation considered airport operations and airway operations for both large and small aircraft. The approach to evaluating aviation accident hazards is similar to that discussed in Subsection 19.58.2.1 for severe winds and tornados. Two screening criteria are used to determine whether a detailed analysis is required: (1) event frequency is less than 1.0E-07 events/year, and (2) CDF associated with aviation accidents is less than 1.0E-08 events/year.

As can be seen from Table 19.58-203, which uses the methodology described in Subsection 2.2.2.7.2 for determining the event frequency, the total annual aircraft accident frequency, considering all types of aircraft, is 3.86E-06, and thus exceeds the first screening criteria. Therefore, an evaluation of CDF associated with aviation accidents was performed.

Risk (CDF) due to aircraft accident hazards can be estimated using the following equation:

$$CDF = IEF * CCDP$$

where IEF is the initiating event frequency and CCDP is the conditional core damage probability.

DCD Appendix 19F includes an assessment of the effects on the plant from the beyond design basis impact of a large commercial aircraft accident. The evaluation of plant damage caused by the impact of a commercial aircraft involves phenomena associated with structural impact, shock-induced vibration and fire effects. The assessment of the aircraft impact also considers structural damage that is caused by impact/penetration of hardened components such as engine rotors and landing gear. DCD Subsection 19F.4.1 concludes that safety-related components inside containment, including the reactor pressure vessel and passive core cooling system, would remain intact and maintain their intended function following the shock-induced vibrations resulting from the impact of a large commercial aircraft.

Accordingly, to establish appropriate CCDPs for the aircraft accidents, it was conservatively assumed that the crash of any aircraft causes an LOSP along with the failure of standby non-safety systems, which are not protected by the reactor containment structures. A CCDP value of 5.85E-08 (Reference 201) represents an LOSP along with the additional failure of standby non-safety systems and was applied to all aviation accidents in the base case. Application of this CCDP to small aircraft accidents is conservative, as it is highly unlikely that a small aircraft would be capable of causing such extensive failures for an AP1000 plant. However, large aircraft crashes would be expected to result in more severe consequences than small aircraft crashes and it is more reasonable to assume that the crash of a large aircraft causes LOSP along with failure of the standby non-safety systems.

To make this distinction between small and large aircraft crashes in the aircraft crash hazard evaluation for Turkey Point Units 6 & 7, a sensitivity evaluation was performed where the CCDP associated with large aircraft accidents was conservatively increased by two orders of magnitude.

The results of the base and sensitivity cases are provided in Table 19.58-203. The resulting CDFs associated with the base case (2.26E-13 events/year) and sensitivity case (1.19E-12 events/year) are both below the screening criterion of 1.0E-08 events/year, and further analysis is not required.

19.58.4 REFERENCES

201. APP-GW-GLR-101, *AP1000 Probabilistic Risk Assessment Site-Specific Considerations*, Rev. 1.

PTN DEP 19.58-1

Table 19.58-201
High Winds and Tornadoes Results for Units 6 & 7

Category	Event	Limiting Initiating Event Frequency (events/yr)	CDF (events/yr)		
			LOSP (Case 1) (events/yr)	LOSP with Non-Safety Systems Unavailable for Select Events (Case 2) (events/yr)	LOSP with Non-Safety Systems Unavailable for All Events (Case 3) (events/yr)
High Winds	EF0 Tornado	2.39E-05	2.34E-13	2.34E-13	1.40E-12
	EF1 Tornado	1.81E-05	1.78E-13	1.78E-13	1.06E-12
	EF2 Tornado	4.30E-05	4.22E-13	4.22E-13	2.52E-12
	EF3 Tornado	1.64E-05	1.61E-13	9.59E-13	9.59E-13
	EF4 Tornado	1.64E-05	1.61E-13	9.59E-13	9.59E-13
	EF5 Tornado	1.64E-05	1.61E-13	9.59E-13	9.59E-13
	Cat. 1 Hurricane	1.02E-01	1.00E-09	1.00E-09	5.97E-09
	Cat. 2 Hurricane	5.10E-02	5.00E-10	5.00E-10	2.98E-09
	Cat. 3A Hurricane	2.57E-02	2.52E-10	2.52E-10	1.50E-09
	Cat. 3B Hurricane	5.73E-02	5.62E-10	3.35E-10	3.35E-09
	Cat. 4 Hurricane	6.40E-02	6.28E-10	3.74E-09	3.74E-09
	Cat. 5 Hurricane	1.90E-02	1.86E-10	1.11E-09	1.11E-09
	Extratropical Cyclones	1.90E-02	1.86E-10	1.86E-10	1.11E-09
Totals			3.3E-09	1.0E-08	2.0E-08

Table 19.58-202 (Sheet 1 of 5)
External Event Frequencies for Turkey Point Units 6 & 7

Category	Event	Evaluation Criteria (See Notes)	Applicable to Site? (Y/N)[1]	Explanation of Applicability Evaluation	Event Frequency (Events/yr)
High Winds	EF0 Tornado	A, C	Y	Turkey Point tornado activity is provided in Subsection 2.3.1.3.2. The event frequency was determined for the 2-degree square area including all or portions of six counties (Broward, Collier, Hendry, Miami-Dade, Monroe, and Palm Beach). There were 297 tornadoes from the six counties that occurred in the 2-degree square in the 58.58 years (1/1/1950 to 7/31/2008) of data examined. Average areas were calculated for each EF scale tornado and assigned to all storms, even if damage path data was not included in a record. Area was normalized by the land area of the 2-degree square. There being no EF Category 4 or 5 events in the 2-degree area during the period of record, the event frequency was es imated to be the same as for an EF3 tornado. The tornado event frequency for each category is bounded by the associated limiting initiating event frequency given in Table 3.0-1 of APP-GW-GLR-101. However, because event frequencies related to hurricanes are not bounded by Table 3.0-1 of APP-GW-GLR-101 a screening CDF evaluation for high winds was performed (FSAR Subsection 19.58.2.1), and the results documented in Table 19.58-201. Based on this analysis, a more detailed PRA is not necessary for Turkey Points Units 6 & 7.	2.39E-05
	EF1 Tornado	A, C	Y		1.81E-05
	EF2 Tornado	A, C	Y		4.30E-05
	EF3 Tornado	A, C	Y		1.64E-05
	EF4 Tornado	A, C	Y		1.64E-05
	EF5 Tornado	A, C	Y		1.64E-05
	Cat. 1 Hurricane	C	Y	The National Oceanic and Atmospheric Administration's Coastal Services Center provides a comprehensive historical database, extending from 1851 through 2007, of tropical cyclone tracks based on information compiled by the National Hurricane Center. Subsection 2.3.1.3.3 summarizes the occurrence of the various categories of hurricanes that have tracked within 100-nautical miles from the Turkey Point Units 6 & 7. This data was used to analyze the event frequency of 12 hurricane activity. The event frequency is determined by dividing the number of occurrences of tropical weather by the period of record (157 years). In each of the hurricane categories, wi h the exception of he extratropical storms, the event frequency exceeds the limi ing initiating event frequency given in Table 3 0-1 of the APP-GW-GLR-101. As documented in FSAR Table 2.0-201 the Turkey Point Units 6 & 7 site characteristic tornado wind loadings (200 mph) are less than the AP1000 DCD site characteristic tornado wind loadings (300 mph). However, he Turkey Point Units 6 & 7 site characteristic operating basis wind speed (150 mph-3 second gust, 50 year return) exceeds the DCD site characteristic operating wind speed of 145 mph (PTN DEP 2.0-1). Based on the screening CDF evaluation presented in FSAR Subsection 19.58.2.1 and the results documented in Table 19.58-202, a more detailed PRA is not necessary for Turkey Points Units 6 & 7.	1.02E-01
	Cat. 2 Hurricane	C	Y		5.10E-02
	Cat. 3 Hurricane	C	Y		8.30E-02
	Cat. 4 Hurricane	C	Y		6.40E-02
	Cat. 5 Hurricane	C	Y		1.90E-02
	Extratropical Cyclones	A, C	Y		1.90E-02

Table 19.58-202 (Sheet 2 of 5)
External Event Frequencies for Turkey Point Units 6 & 7

Category	Event	Evaluation Criteria (See Notes)	Applicable to Site? (Y/N)[1]	Explanation of Applicability Evaluation	Event Frequency (Events/yr)
External Flood	External Flood	D	N	Potential flooding events and the determination of the design basis flood elevation that may affect Turkey Point Units 6 & 7 safety-related facilities are described in Subsection 2.4.2. The design basis flooding elevation for Turkey Point Units 6 & 7 is determined by considering a number of different flooding scenarios. The potential flooding scenarios applicable and investigated for Turkey Point Units 6 & 7 include the following: probable maximum flood (PMF) on streams and rivers, potential dam failures, probable maximum surge and seiche flooding, probable maximum tsunami, flooding due to ice effects, and potential flooding caused by channel diversions. The flooding scenarios were investigated in conjunction with other flooding and meteorological events, such as wind-generated waves and tidal levels, as recommended in the guidelines presented in ANSI/ANS-2.8-1992. PMF on streams and rivers: Flooding due to the PMF on streams and rivers is assessed and described in Subsection 2.4.3. The PMF on streams and rivers is defined by the probable maximum precipitation (PMP) storm event over the stream or river watershed. As addressed in Subsection 2.4.3, flood levels at Turkey Point Units 6 & 7 during severe storms, such as the PMP event, would be controlled by storm tides in the Biscayne Bay because Turkey Point Units 6 & 7 are located on the Biscayne Bay shoreline and there are no major streams or rivers nearby. As a result, a detailed modeling analysis to determine the flood levels from PMF on streams and rivers was not performed for Turkey Point Units 6 & 7. Potential dam failures: There are no dams located upstream or downstream of Turkey Point Units 6 & 7. The makeup water reservoir, located south of the power block, is constructed of a concrete basin with a top of basin wall at 24 feet NAVD 88, which is 2 feet below the design grade of 26 feet NAVD 88 for the safety-related structures. It is concluded in Subsection 2.4.4 that a postulated breach of the reservoir wall would not pose a flooding risk to the safety-related facilities of the plant. Probable maximum surge and seiche flooding: Probable maximum surge and seiche flooding as a result of the probable maximum hurricane (PMH) is presented in Subsection 2.4.5. The maximum water surface elevation including wave run-up at the plant area during the postulated passage of the PMH is estimated to be 24.8 feet NAVD 88. This flood level also constitutes the design basis flood eleva ion for the site, and is below the design grade including the elevation of floor entrances and openings of all safety-related facilities at 26 feet NAVD 88. Thus, the safety functions of the plant are not impacted by the PMH-induced flooding.	N/A

Table 19.58-202 (Sheet 3 of 5)
External Event Frequencies for Turkey Point Units 6 & 7

Category	Event	Evaluation Criteria (See Notes)	Applicable to Site? (Y/N)[1]	Explanation of Applicability Evaluation	Event Frequency (Events/yr)
External Flood (Continued)				Probable maximum tsunami: Subsection 2.4.6 describes the estimation of flood levels associated with the probable maximum tsunami (PMT). The maximum water level associated with the PMT at Units 6 & 7 is conservatively estimated to be 16.7 feet NAVD 88. Therefore, the PMT does not pose a flood risk to the safety-related facilities for Units 6 & 7. Flooding due to ice effects: Based on the historical data assessed in Subsection 2.4.7, it is unlikely that ice effects would pose any flood risk to Units 6 & 7. Potential flooding caused by channel diversions: Subsection 2.4.9 describes the effects of channel diversions, and it is determined that channel diversion would not pose any flood risk to Turkey Point Units 6 & 7. The maximum water level at Turkey Point Units 6 & 7 due to a local PMP storm event is estimated and described in Subsection 2.4.2.3. Because the design plant grade (26.0 feet NAVD 88), including the elevation of the openings and entrances to he Turkey Point Units 6 & 7 safety-related buildings, is located above the design basis flood elevation (24.8 feet NAVD 88), as described in Subsection 2.4.2, the safety-related functions of the plant will not be adversely impacted by flooding events. Subsection 2.4.10 describes he flooding protection requirements for Turkey Point Units 6 & 7.	
Transportation and Nearby Facility Accidents	Aviation (commercial/ general/military)	C	Y	As discussed in Subsec ion 2.2.2.7.2, a calculation to determine the probability of an aircraft accident into he plant and its impact frequency was performed following NUREG-0800 and DOE-STD-3014-96 methodology to determine whether the accident probability rate (external event frequency) is less than an order of magnitude of 1.0E-07 events per year. This assessment led to a total impact frequency of 3.86E-06 per year when considering both the airport and non-airport operations, which is an order of magnitude greater than 1.0E-07 per year. Because the total impact frequency (external event frequency) is greater than 1.0E-07 events per year, a determination was made to ascertain whe her the external event frequencies are bounded by he limiting event frequency criterion given in APP-GW-GLR-101. The event frequency numbers were compared to the limiting event frequency numbers, 1.21E-06 and 1.0E-07, for small and large aircraft, respectively, given in APP-GW-GLR-101. (Note, commercial air carrier aircraft, commercial air taxi aircraft, military small aircraft, and military large aircraft are included in the large aircraft category.) The determined impact frequency also exceeded the limiting event frequency of 1.21E-06 events per year for small aircraft in APP-GW-GLR-101. However, based on the screening CDF evaluation presented in Subsection 19.58.2.3.1 and the results documented in Table 19.58-203, the second criterion, the CDF is not greater than about 1.0E-08, is met and the further detailed PRA is not necessary for Turkey Point Units 6 & 7.	General Aviation: 3.70E-06 Commercial Aviation Carrier: 1.72E-08 Commercial Aviation Air Taxi: 3.86E-08 Military Aviation-Large: 2.38E-08 Military Avia ion-Small: 8.66E-08 Total: 3.86E-06

Table 19.58-202 (Sheet 4 of 5)
External Event Frequencies for Turkey Point Units 6 & 7

Category	Event	Evaluation Criteria (See Notes)	Applicable to Site? (Y/N)[1]	Explanation of Applicability Evaluation	Event Frequency (Events/yr)
Transportation and Nearby Facility Accidents (Continued)	Marine (ship/barge)	D	N	As described in Subsection 2.2.2.4, Turkey Point Units 6 & 7 are located on the western shore of south Biscayne Bay. Biscayne Bay is a shallow coastal lagoon located on the lower southeast coast of Florida. The Biscayne Bay contains the Miami to Key West, Florida Intracoastal Waterway. The only commodity transported on the Miami to Key West, Florida Intracoastal Waterway is residual fuel oil. In 2005, there were 611,000 short tons of residual fuel oil transported, and the en irety of this commodity was delivered to the Turkey Point Units 1-5 site. Because the storage of residual fuel oil at the Turkey Point Units 1-5 site exceeds the quantity transported by a barge, the storage tanks present a greater hazard and, as such, the analysis of residual fuel oil located in the storage tanks is bounding and no further analysis of the residual fuel oil transported by the barge is warranted.	N/A
	Pipeline (gas/oil)	D	N	As described in Subsection 2.2.2 3, there are two natural gas transmission pipelines operated by Florida Gas Transmission Company within 5 miles of the plant. The Florida Gas Transmission Company owns and operates a high-pressure natural gas pipeline system that serves FPL and other customers in sou h Florida. Two of the pipelines, the Turkey Point Lateral and the Homestead Lateral, are located within 5 miles of Turkey Point Units 6 & 7. As discussed in Subsections 2.2.3.1.1.7, 2.2.3.1.2.7, and 2.2.3.1.3.5, the postulated scenarios resulting from a release of the bounding natural gas pipeline within 5 miles of the Turkey Point Unit 6 & 7 site do not pose a credible hazard to the site.	N/A
	Railroad	D	N	As discussed in Subsec ion 2.2.2.6, there are no railroads in the vicinity (5 miles) of Turkey Point Units 6 & 7. Thus, the safety functions of the plant are not impacted by the hazards from this source.	N/A
	Truck	D	N	A description of the highways in the vicinity of Turkey Point Units 6 & 7 is presented in Subsection 2.2.2.5. The only identified chemicals whose transportation route may approach closer han 5 miles to Turkey Point Units 6 & 7 are those chemicals transported onto the Turkey Point plant property. Of these chemicals, gasoline was the only identified roadway transportation event that is not bounded. As discussed in Subsections 2 2.3.1.1.6, 2.2.3.1.2.6, and 2.2.3.1.3.4, the potential hazards resulting from the truck transport of gasoline concluded that there were no adverse impacts to the site.	N/A
	Nearby Facility Accidents	D	N	As detailed in Subsections 2.2.2.2.1, and 2.2.2.2.2, two nearby facilities were evaluated, Turkey Point Units 1-5, and the Homestead Air Reserve Base. Based on he discussions in Subsections 2.2.3.1.1.3, 2.2.3.1.2.3, and 2.2.3.1.3.1 (Turkey Point Units 1-5) and Subsections 2.2.3.1.1.5, 2.2.3.1.2.5, and 2.2.3.1.3 3 (Homestead Air Reserve), the effects of explosions, flammable vapor clouds and toxic chemicals at Turkey Point Units 1-5 and the Homestead Air Reserve Base were evaluated and determined to meet the safe distance requirements and toxicity limits of Regulatory Guides 1.91 and 1.78. Therefore, because no significant consequences were identified for hese events, the potential safety effect from nearby facilities to the site is insignificant.	N/A

Table 19.58-202 (Sheet 5 of 5)
External Event Frequencies for Turkey Point Units 6 & 7

Category	Event	Evaluation Criteria (See Notes)	Applicable to Site? (Y/N)[1]	Explanation of Applicability Evaluation	Event Frequency (Events/yr)
Other Events	External Fires	D	N	External fires in the vicinity of the Turkey Point Units 6 & 7 site that could lead to high heat fluxes or smoke and nonflammable gas or chemical-bearing clouds from he release of materials as a consequence of fires have been addressed in Subsec ion 2.2.3.1.4. Fires in adjacent industrial plants and storage facilities–chemical, oil and gas pipelines; brush and forest fires; and fires from transportation accidents–were evaluated as events that could lead to high heat fluxes or to the formation of such clouds. Based on the above, it is demonstrated that there are no external fire events that adversely affect Turkey Point Units 6 & 7. Therefore, no further consideration of external fires is required in the PRA analysis. This event is not specifically addressed in DCD Section 19.58 or in APP-GW-GLR-101, though DCD Section 19.58 does state that the COL applicant should reevaluate and include external fires in the site specific PRA if any site specific susceptibilities are found. As discussed above, no site specific susceptibilities have been identified for the Turkey Point Units 6 & 7 site, therefore the evaluations presented in DCD Section 19.58 and APP-GW-GLR-101 are bounding to the Turkey Point Units 6 & 7 site.	N/A
	On-Site Chemical Storage	D	N	Potential hazards from on-site storage tanks are addressed in Subsections 2.2.3.1.1.4, Subsections 2.2.3.1.2.4, and 2.2.3.1.3.2. Chemicals not screened from further considera ion on the basis of chemical properties such as low toxicity or volatility have been specifically evaluated. Chemicals with potential explosion or flammable vapor cloud hazards have been evaluated in accordance wi h Regulatory Guide 1.91 as described in Subsections 2.2.3.1.1 and 2.2.3.1.2. Chemicals with potential hazards to control room personnel have been evaluated using the methodology of Regulatory Guide 1.78 as described in Subsection 2.2.3.1.3. Based upon the quantitative evalua ions performed, it is concluded that these evaluations demonstrate through bounding analyses that these hazards do not adversely affect Turkey Point Units 6 & 7. Therefore, the hazard can be excluded from further consideration in the PRA analysis. This event is not specifically addressed in DCD Section 19.58 or in APP-GW-GLR-101. As discussed, the event screens out from further PRA considerations, therefore the evaluations presented in DCD Section 19.58 and APP-GW-GLR-101 are bounding to the Turkey Point Units 6 & 7 site.	N/A

Notes:

1. An event is applicable (Y) to the Turkey Point Units 6 & 7 site if the external event frequency is greater than 1.0E-07, or if a quantita ive consequence evaluation has demonstrated that there are site specific parameters that exceed the parameters used in APP-GW-GLR-101 (Reference 201). An event is not applicable (N) to the Turkey Point Units 6 & 7 site if the external event frequency is less than 1.0E-07 or if the quantitative consequence evaluation performed in the FSAR has demonstrated hat the event will not adversely impact he safe operation of the Turkey Point Units 6 & 7.

Evaluation Criteria:

A: The initiating event frequency (IEF) is less than the IEF in DCD Tier 2 Section 19.58 or Table 19.58-3 for the event.
B: External Event Frequency is less than 1.0E-07.
C: Core Damage frequency (CDF) is less than 1.0E-08.
D: A specific event frequency for this event has not been determined. A deterministic quantitative consequence evaluation has been performed that has demonstrated that the event does not adversely impact the safe operation of Turkey Point Units 6 & 7. Additional details are provided in the "Explanation of Applicability Evaluation" with references to the applicable FSAR Subsections.

Table 19.58-203
Aircraft Impact Frequency and Resulting Core Damage Frequency (CDF)

Aircraft Type	Impact Frequency (Events/Year)	Conditional Core Damage Probability		CDF (Events/Year)	
		Base	Sensitivity	Base	Sensitivity
General Aviation	3.70E-06	5.85E-08	5.85E-08	2.16E-13	2.16E-13
Commercial Carrier	1.72E-08	5.85E-08	5.85E-06	1.01E-15	1.01E-13
Commercial Air Taxi	3.86E-08	5.85E-08	5.85E-06	2.26E-15	2.26E-13
Military – Large	2.38E-08	5.85E-08	5.85E-06	1.39E-15	1.39E-13
Military – Small	8.66E-08	5.85E-08	5.85E-06	5.07E-15	5.07E-13
Total[(a)]	3.86E-06	—	—	2.26E-13	1.19E-12

(a) The totals are slightly different than the sum of the individual frequencies shown due to rounding.

19.59 PRA RESULTS AND INSIGHTS

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

19.59.10.5 Combined License Information

STD COL 19.59.10-1
STD COL 19.59.10-6

A review of the differences between the as-built plant and the design used as the basis for the AP1000 seismic margins analysis will be completed prior to fuel load. A verification walkdown will be performed with the purpose of identifying differences between the as-built plant and the design. Any differences will be evaluated and the seismic margins analysis modified as necessary to account for the plant-specific design, and any design changes or departures from the certified design. A comparison of the as-built SSC high confidence, low probability of failures (HCLPFs) to those assumed in the AP1000 seismic margin evaluation will be performed prior to fuel load. Deviations from the HCLPF values or assumptions in the seismic margin evaluation due to the as-built configuration and final analysis will be evaluated to determine if vulnerabilities have been introduced. The requirements to which the equipment is to be purchased are included in the equipment specifications. Specifically, the equipment specifications include:

1. Specific minimum seismic requirements consistent with those used to define the AP1000 DCD Table 19.55-1 HCLPF values.

   This includes the known frequency range used to define the HCLPF by comparing the required response spectrum (RRS) and test response spectrum (TRS). The test response spectra are chosen so as to demonstrate that no more than one percent rate of failure is expected when the equipment is subjected to the applicable seismic margin ground motion for the equipment identified to be applicable in the seismic margin insights of the site-specific PRA. The range of frequency response that is required for the equipment with its structural support is defined.

2. Hardware enhancements that were determined in previous test programs and/or analysis programs will be implemented.

STD COL 19.59.10-2 A review of the differences between the as-built plant and the design used as the basis for the AP1000 PRA and DCD Table 19.59-18 will be completed prior to fuel load. The plant specific PRA-based insight differences will be evaluated and the plant specific PRA model modified as necessary to account for plant-specific design and any design changes or departures from the design certification PRA.

As discussed in Section 19.58.2.1, it has been confirmed that the Winds, Floods, and Other External Events analysis documented in DCD Section 19.58 is applicable to the site. The site-specific design has been evaluated and is consistent with the AP1000 PRA assumptions. Therefore, Section 19.58 of the AP1000 DCD is applicable to this design.

STD COL 19.59.10-3 A review of the differences between the as-built plant and the design used as the basis for the AP1000 internal fire and internal flood analyses will be completed prior to fuel load. Plant specific internal fire and internal flood analyses will be evaluated and the analyses modified as necessary to account for the plant-specific design, and any design changes or departures from the certified design.

STD COL 19.59.10-4 The AP1000 Severe Accident Management Guidance (SAMG) from APP-GW-GLR-070, Reference 1 of DCD Section 19.59, is implemented on a site-specific basis. Key elements of the implementation include:

- SAMG based on APP-GW-GLR-070 is provided to Emergency Response Organization (ERO) personnel in assessing plant damage, planning and prioritizing response actions and implementing strategies that delineate actions inside and outside the control room.
- Severe accident management strategies and guidance are interfaced with the Emergency Operating Procedures (EOP's) and Emergency Plan.
- Responsibilities for authorizing and implementing accident management strategies are delineated as part of the Emergency Plan.
- SAMG training is provided for ERO personnel commensurate with their responsibilities defined in the Emergency Plan.

STD COL 19.59.10-5 A thermal lag assessment of the as-built equipment required to mitigate severe accidents (hydrogen igniters and containment penetrations) will be performed to provide additional assurance that this equipment can perform its severe accident functions during environmental conditions resulting from hydrogen burns associated with severe accidents. This assessment will be performed prior to fuel load and is required only for equipment used for severe accident mitigation that has not been tested at severe accident conditions. The ability of the as-built equipment to perform during severe accident hydrogen burns will be assessed using the Environment Enveloping method or the Test Based Thermal Analysis method discussed in EPRI NP-4354 (DCD Section 19.59 Reference 3).

STD COL 19.59.10-6
PTN COL 19.59.10-6 As discussed in Subsection 19.55.6.3, it has been confirmed that the Seismic Margin Analysis (SMA) documented in DCD Section 19.55 is applicable to the site. The site-specific effects (i.e., soil-related failure modes, etc.) have been evaluated and it was concluded that the plant-specific plant level HCLPF value is equal to or greater than 1.67 times the site-specific GMRS peak ground acceleration.

Add the following new information after DCD Subsection 19.59.10.5:

STD SUP 19.59-1

19.59.10.6 PRA Configuration Controls

PRA configuration controls contain the following key elements:

- A process for monitoring PRA inputs and collecting new information.
- A process that maintains and updates the PRA to be reasonably consistent with the as-built, as operated plant.
- A process that considers the cumulative impact of pending changes when applying the PRA.
- A process that evaluates the impact of changes on currently implemented risk-informed decisions that have used the PRA.
- A process that maintains configuration control of computer codes used to support PRA quantification.

- A process for upgrading the PRA to meet PRA standards that the NRC has endorsed.

- Documentation of the PRA.

PRA configuration controls are consistent with the regulatory positions on maintenance and upgrades in Regulatory Guide 1.200.

Schedule for Maintenance and Upgrades of the PRA

The PRA update process is a means to reasonably reflect the as designed and as operated plant configurations in the PRA models. The PRA upgrade process includes an update of the PRA plus a general review of the entire PRA model, and as applicable the application of new software that implements a different methodology, implementation of new modeling techniques, as well as a comprehensive documentation effort.

- During construction, the PRA is upgraded prior to fuel load to cover those initiating events and modes of operation contained in NRC-endorsed consensus standards on PRA in effect one year prior to the scheduled date of the initial fuel load for a Level 1 and Level 2 PRA.

- Prior to license renewal the PRA is upgraded to include all modes of operation.

- During operation, PRA updates are completed as part of the upgrade process at least once every four years.

- A screening process is used to determine whether a PRA update should be performed more frequently based upon the nature of the changes in design or procedures. The screening process considers whether the changes affect the PRA insights. Changes that do not meet the threshold for immediate update are tracked for the next regulatory scheduled update. If the screening process determines that the changes do warrant a PRA update, the update is made as soon as practicable consistent with the required change importance and the applications being used.

PRA upgrades are performed in accordance with 10 CFR 50.71(h).

Process for Maintenance and Upgrades of the PRA

Various information sources are monitored to determine changes or new information that affects the model assumptions or quantification. Plant specific design, procedure, and operational changes are reviewed for risk impact. Information sources include applicable operating experience, plant modifications, engineering calculation revisions, procedure changes, industry studies, and NRC information.

The PRA upgrade includes initiating events and modes of operation contained in NRC-endorsed consensus standards on PRA in effect one year prior to each required upgrade.

This PRA maintenance and update incorporates the appropriate new information including significant modeling errors discovered during routine use of the PRA.

Once the PRA model elements requiring change are identified, the PRA computer models are modified and appropriate documents revised. Documentation of modifications to the PRA model include the changes as well as the upgraded portions clearly indicating what has been changed. The impact on the risk insights is clearly indicated.

PRA Quality Assurance

Maintenance and upgrades of the PRA are subject to the following quality assurance provisions:

Procedures identify the qualifications of personnel who perform the maintenance and upgrade of the PRA.

Procedures provide for the control of PRA documentation, including revisions.

For updates of the PRA, procedures provide for independent review, or checking of the calculations and information.

Procedures provide for an independent review of the model after an upgrade is completed. Additionally, after the PRA is upgraded, the PRA is reviewed by outside PRA experts such as industry peer review teams and the comments incorporated to maintain the PRA current with industry practices. Peer review findings are entered into a tracking system. PRA upgrades receive a peer review for those aspects of the PRA that are upgraded.

PRA models and applications are documented in a manner that facilitates peer review as well as future updates and applications of the PRA by describing the processes that were used, and provide details of the assumptions made and their bases. PRA documentation is developed such that traceability and reproducibility is maintained. PRA documentation is maintained in accordance with Regulatory Position 1.3 of Regulatory Guide 1.200.

Procedures provide for appropriate attention or corrective actions if assumptions, analyses, or information used previously are changed or determined to be in error. Potential impacts to the PRA model (i.e., design change notices, calculations, and procedure changes) are tracked. Errors found in the PRA model between periodic updates are tracked using the site tracking system.

PRA-Related Input to Other Programs and Processes

The PRA provides input to various programs and processes, such as the Maintenance Rule implementation, reactor oversight process, the RAP, and the RTNSS program. The use of the PRA in these programs is discussed below, or cross-references to the appropriate FSAR sections are provided.

PRA Input to Design Programs and Processes

The PRA insights identified during the design development are discussed in DCD Subsection 19.59.10.4 and summarized in DCD Table 19.59-18. DCD Section 14.3 summarizes the design material contained in AP1000 that has been incorporated into the Tier 1 information from the PRA. A discussion of the plant features important to reducing risk is provided in DCD Subsection 19.59.9.

PRA Input to the Maintenance Rule Implementation

The PRA is used as an input in determining the safety significance classification and bases of in-scope SSCs. SSCs identified as risk-significant via the Reliability Assurance Program for the design phase (DRAP, Section 17.4) are included within the initial Maintenance Rule scope as high safety significance SSCs.

For risk-significant SSCs identified via DRAP, performance criteria are established, by the Maintenance Rule expert panel using input from the reliability and availability assumptions used in the PRA, to monitor the effectiveness of the maintenance performed on the SSCs.

The Maintenance Rule implementation is discussed in Section 17.6.

PRA Input to the Reactor Oversight Process

The mitigating systems performance indicators (MSPI) are evaluated based on the indicators and methodologies defined in NEI 99-02 (Reference 201).

The Significance Determination Process (SDP) uses risk insights, where appropriate, to determine the safety significance of inspection findings.

PRA Input to the Reliability Assurance Program

The PRA input to the Reliability Assurance Program is discussed in DCD Subsection 19.59.10.1.

PRA Input to the Regulatory Treatment of Nonsafety-Related Systems Programs

The importance of nonsafety-related SSCs in the AP1000 has been evaluated using PRA insights to identify SSCs that are important in protecting the utility's investment and for preventing and mitigating severe accidents. These investment protection systems, structures and components are included in the D-RAP/MR Program (refer to Subsection 17.4), which provides confidence that availability and reliability are designed into the plant and that availability and reliability are maintained throughout plant life through the maintenance rule. Technical Specifications are not required for these SSCs because they do not meet the selection criteria applied to the AP1000 (refer to Subsection 16.1.1).

MOV Program

The MOV Program includes provisions to accommodate the use of risk-informed inservice testing of MOVs (Subsection 3.9.6).

19.59.11 REFERENCES

Add the following text to the end of DCD Subsection 19.59.11:

201. Nuclear Energy Institute, *Regulatory Assessment Performance Indicator Guideline*, Technical Report NEI 99-02, Rev. 5, July 2007.

PTN DEP 6.3-1

TABLE 19.59-18R
AP1000 PRA-BASED INSIGHTS

Insight	Disposition
1e. (cont.)	
Long-term cooling of PRHR will result in steaming to the containment. The steam will normally condense on the containment shell and return to the IRWST by safety-related features. Connections are provided to IRWST from the spent fuel system (SFS) and chemical and volume control system (CVS) to extend PRHR operation. A safety-related makeup connection is also provided from outside the containment through the normal residual heat removal system (RNS) to the IRWST.	6.3.1 & system drawings
Capability exists and guidance is provided for the control room operator to identify a leak in the PRHR HX of 500 gpd. This limit is based on the assumption that a single crack leaking this amount would not lead to a PRHR HX tube rupture under the stress conditions involving the pressure and temperature gradients expected during design basis accidents, which the PRHR HX is designed to mitigate.	6.3.3 & 16.1
The positions of the inlet and outlet PRHR valves are indicated and alarmed in the control room.	6.3.7
PRHR air-operated valves are stroke-tested quarterly. The PRHR HX is tested to detect system performance degradation every 10 years.	3.9.6
PRHR is required by Technical Specifications to be available from Modes 1 through 5 with RCS pressure boundary intact.	16.1
The PRHR HX, in conjunction with the IRWST, the condensate return features and the PCS, can provide core cooling for greater than 14 days. After the IRWST water reaches its saturation temperature, the process of steaming to the containment initiates. Condensation occurs on the steel containment vessel, and the condensate is collected in a safety-related gutter arrangement, which returns the condensate to the IRWST. The gutter normally drains to the containment sump, but when the PRHR HX actuates, safety-related isolation valves in the gutter drain line shut and the gutter overflow returns directly to the IRWST. The following design features provide proper re-alignment for the gutter system valves to direct water to the IRWST:	6.3.2.1.1 & 6.3.7.6
- IRWST gutter and its drain isolation valves are safety-related	
- These isolation valves are designed to fail closed on loss of compressed air, loss of Class 1E dc power, or loss of the PMS signal	
- These isolation valves are actuated automatically by PMS and DAS.	7.3.1.2.7
The PRHR subsystem provides a safety-related means of removing decay heat following loss of RNS cooling during shutdown conditions with the RCS intact.	16.1

APPENDIX 19A THERMAL HYDRAULIC ANALYSIS TO SUPPORT SUCCESS CRITERIA

This section of the referenced DCD is incorporated by reference with no departures or supplements.

APPENDIX 19B EX-VESSEL SEVERE ACCIDENT PHENOMENA

This section of the referenced DCD is incorporated by reference with no departures or supplements.

APPENDIX 19C ADDITIONAL ASSESSMENT OF AP1000 DESIGN FEATURES

This section of the referenced DCD is incorporated by reference with no departures or supplements.

APPENDIX 19D EQUIPMENT SURVIVABILITY ASSESSMENT

This section of the referenced DCD is incorporated by reference with no departures or supplements.

APPENDIX 19E SHUTDOWN EVALUATION

This section of the referenced DCD is incorporated by reference with the following departures and/or supplements.

19E.2.3.2.6 Discussion of Safe Shutdown for AP1000

Replace the DCD Subsection 19E.2.3.2.6 with the following information:

PTN DEP 3.2-1

The functional requirements for the PXS specify that the plant be brought to a safe, stable condition using the PRHR HX for events not involving a loss of coolant. As stated in Subsection 6.3.1.1.1, the PRHR HX in conjunction with the passive containment cooling system (PCS) provides sufficient heat removal to satisfy the post-accident safety evaluation criteria for at least 72 hours. Additionally, the PXS, in conjunction with the passive containment cooling system and the automatic depressurization system (ADS), has the capability to establish long-term safe shutdown conditions in the reactor coolant system as identified in Subsection 7.4.1.1.

The CMTs automatically provide injection to the RCS after they are actuated on low reactor coolant temperature or low pressurizer pressure or level. The PXS can maintain stable plant conditions for a long time in this mode of operation, depending on the reactor coolant leakage and the availability of ac power sources. For example, with a technical specification leak rate of 10 gpm, stable plant conditions can be maintained for at least 10 hours. With a smaller leak a longer time is available.

In scenarios when ac power sources are unavailable for approximately 22 hours, the automatic depressurization system automatically actuates. However, after the initial plant cooldown following a non-LOCA event, operators assess plant conditions and have the option to perform recovery actions to further cool and depressurize the reactor coolant system in a closed-loop mode of operation, i.e., without actuation of the automatic depressurization system. After verifying the reactor coolant system is in an acceptable, stable condition, such that automatic depressurization is not needed, the operators may take action to extend passive residual heat removal heat exchanger operation by de-energizing the loads on the Class 1E dc batteries powering the protection and monitoring system actuation

cabinets. After operators have taken action to extend its operation, the PRHR HX, in conjunction with the passive containment cooling system, has the capability to maintain safe, stable shutdown conditions. The automatic depressurization system remains available to maintain safe shutdown conditions at a later time.

In most sequences the operators would return the plant to normal system operations and terminate passive system operation within several hours in accordance with the plant emergency operating procedures. For LOCAs and other postulated events, when the core makeup tank level reaches the automatic depressurization actuation setpoint, and other postulated events where the PRHR HX operation is not extended or is exhausted, ADS may be initiated. This results in injection from the accumulators and subsequently from the in-containment refueling water storage tank, once the RCS is nearly depressurized. For these conditions, the RCS depressurizes to saturated conditions at about 250°F within 24 hours. The PXS can maintain this safe shutdown condition as identified in Subsection 7.4.1.1.

The primary function of the PXS during a safe shutdown using only safety-related equipment is to provide a means for boration, injection, and core cooling. Analysis is provided in Subsection 19E.4.10.2 of this appendix that verifies the ability of the AP1000 passive safety systems to meet the safe shutdown requirements.

19E.2.7.2 Design Features to Address Shutdown Safety

Revise the third paragraph of DCD Subsection 19E.2.7.2 as follows:

PTN DEP 7.3-1

The safety analysis of boron dilution accidents is provided in DCD Chapter 15 and is discussed in DCD Subsection 19E.4.5 of this appendix. For dilution events that occur during shutdown, the source-range flux-doubling signal closes the safety-related remotely operated CVS makeup line isolation valves to terminate the event. In addition, the signal is used to isolate the line from the demineralized water system to the makeup pump suction by closing the two safety-related remotely operated valves. The three-way pump suction control valve aligns the makeup pumps to take suction from the boric acid tank and, therefore, stops the dilution.

19E.4.10.2 Shutdown Temperature Evaluation

Replace DCD Subsection 19E.4.10.2 with the following information.

PTN DEP 3.2-1

As discussed in DCD Subsection 6.3.1.1.4, the passive residual heat removal heat exchanger is required to be able to cool the reactor coolant system to a safe, stable condition after shutdown following a non-LOCA event. The following summarizes a non-bounding, conservative analysis, which demonstrates the passive residual heat removal heat exchanger can meet this criterion and cool the RCS to the specified, safe shutdown condition of 420°F within 36 hours. This analysis demonstrates that the passive systems can bring the plant to a safe, stable condition and maintain this condition so that no transients will result in the specified acceptable fuel design limit and pressure boundary design limit being violated and that no high-energy piping failure being initiated from this condition results in 10 CFR 50.46 (DCD Reference 15) criteria.

As discussed in DCD Subsection 6.3.3 and DCD Subsection 7.4.1.1, the PRHR HX operates to reduce the RCS temperature to the safe shutdown condition following a non-LOCA event. An analysis of the loss of main feedwater with a loss of ac power event demonstrates that the passive systems can bring the plant to a stable safe condition following postulated transients. A non-bounding, conservative analysis is represented in DCD Figures 19E.4.10-1 through 19E.4.10-4. The progression of this event is outlined in DCD Table 19E.4.10-1. Though some of the assumptions in this evaluation are based on nominal conditions, many of the analysis assumptions are bounding.

The performance of the PRHR HX is affected by the containment pressure. Containment pressure determines the PRHR HX heat sink (the IRWST water) temperature. The WGOTHIC containment response model described in DCD Subsection 6.2.1.1.3 was used to determine the containment pressure response to this transient, which was used as an input to the plant cooldown analysis performed with LOFTRAN. Some changes were made to the WGOTHIC model to ensure the results were conservative for the long-term safe shutdown analysis.

The PRHR HX performance is also affected by the IRWST water level when the level drops below the top of the PRHR HX tubes. The IRWST water level is affected by the heat input from the PRHR HX and by the amount of steam that

leaves the IRWST and does not return to the IRWST through the IRWST gutter arrangement. The principal steam condensate losses include steam that stays in the containment atmosphere, steam that condenses on heat sinks inside containment other than the containment vessel, and dripping or splashing losses due to obstructions on the inner containment vessel wall. The WGOTHIC containment response model also provided the mass balance with respect to the steam lost to the containment atmosphere and to condensation on passive heat sinks other than the containment vessel. The WGOTHIC analysis inputs (including the mass of the heat sinks and heat transfer rates) were biased to increase steam condensate losses. The WGOTHIC model provides the time-dependent condensate return rate which was incorporated into the LOFTRAN computer code described in DCD Subsection 15.0.11.2 to demonstrate that the RCS could be cooled to 420°F within 36 hours.

Summarizing this transient, the loss of normal ac power occurs (offsite and onsite), followed by the reactor trip. The PRHR HX is actuated on the low steam generator narrow range level coincident with low startup feed water flow rate signal. Eventually a safeguards actuation signal is actuated on Low cold leg temperature and the CMTs are actuated.

Once actuated, at about 2,700 seconds, the CMTs operate in recirculation mode, injecting cold borated water into the RCS. In the first part of their operation, due to the injection of cold water, the CMTs operate in conjunction with the PRHR HX to reduce RCS temperature. Due to the primary system cooldown, the PRHR heat transfer capability drops below the decay heat and the RCS cooldown is essentially driven by the CMT cold injection flow. However, at about 6,000 seconds, the CMT cooling effect decreases and the RCS starts heating up again (DCD Figure 19.E.4.10-1). The RCS temperature increases until the PRHR HX can match decay heat. At about 46,700 seconds, the PRHR heat transfer matches decay heat and it continues to operate to reduce the RCS temperature to below 420°F within 36 hours. As seen from DCD Figure 19E.4.10-1, the cold leg temperature in the loop with the PRHR is reduced to 420°F at about 52,900 seconds, while the core average temperature reaches 420°F at about 120,900 seconds (approximately 34 hours).

As discussed in DCD Subsection 7.4.1.1, a timer is used to automatically actuate the automatic depressurization system if offsite and onsite power are lost for about 24 hours. This timer automates putting the open loop cooling features into service prior to draining the Class 1E dc 24-hour batteries that operate the ADS valves. At approximately 22 hours, if the plant conditions indicate that the ADS would not be needed until well after 24 hours, the operators are directed to de-

energize all loads on the 24-hour batteries. This action will block actuation of the ADS and preserves the ability to align open loop cooling at a later time. Operation of the ADS in conjunction with the CMTs, accumulators, and IRWST reduces the RCS pressure and temperature to below 420°F. The ability to actuate ADS and IRWST injection provides a safety-related, backup mode of decay heat removal that is diverse to extended PRHR HX operation.

PTN DEP 6.3-1

As discussed in DCD Subsection 6.3.3.2.1.1, the PRHR HX can operate in this mode for at least 72 hours to maintain RCS conditions within the applicable Chapter 15 safety evaluation criteria. In addition, the analysis supporting this Section shows the PRHR HX is expected to maintain safe shutdown conditions for greater than 14 days. One important consideration with regard to the duration closed-loop cooling can be maintained is the RCS leak rate. This duration of closed-loop cooling can be achieved with expected RCS leak rates. For abnormal leak rates, it may become necessary to initiate open-loop cooling earlier than 14 days.

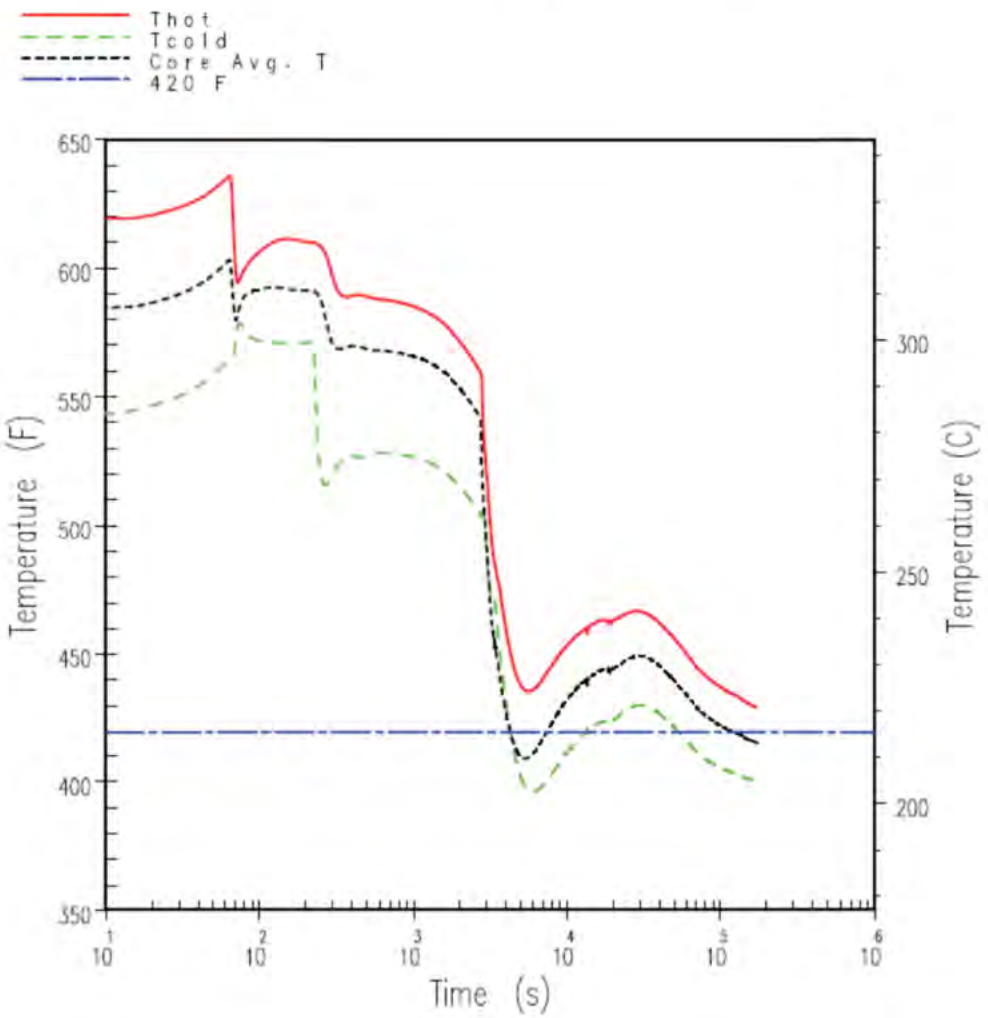
PTN DEP 3.2-1

TABLE 19E.4.10-1R
SEQUENCE OF EVENTS FOLLOWING A LOSS OF AC POWER FLOW WITH CONDENSATE FROM THE CONTAINMENT SHELL BEING RETURNED TO THE IRWST

Event	Time (seconds)
Feedwater is Lost	10.0
Low Steam Generator Water Level (Narrow-Range) Reactor Trip Setpoint Reached	60.6
Rods Begin to Drop	62.6
Low Steam Generator Water Level (Wide-Range) Reached	209.5
PRHR HX Actuation on Low Steam Generator Water Level (Narrow-Range Coincident with Low Startup Feedwater Flow)	221.5
Low T_{cold} Setpoint Reached	2752
Steam Line Isolation on Low T_{cold} Signal	2764
CMTs Actuated on Low T_{cold} Signal	2764
IRWST Reaches Saturation Temperature	15,900
Heat Extracted by PRHR HX Matches Core Decay Heat	46,700
Cold Leg Temperature Reaches 420°F (loop with PRHR)	52,900
Core Average Temperature Reaches 420°F	120,900

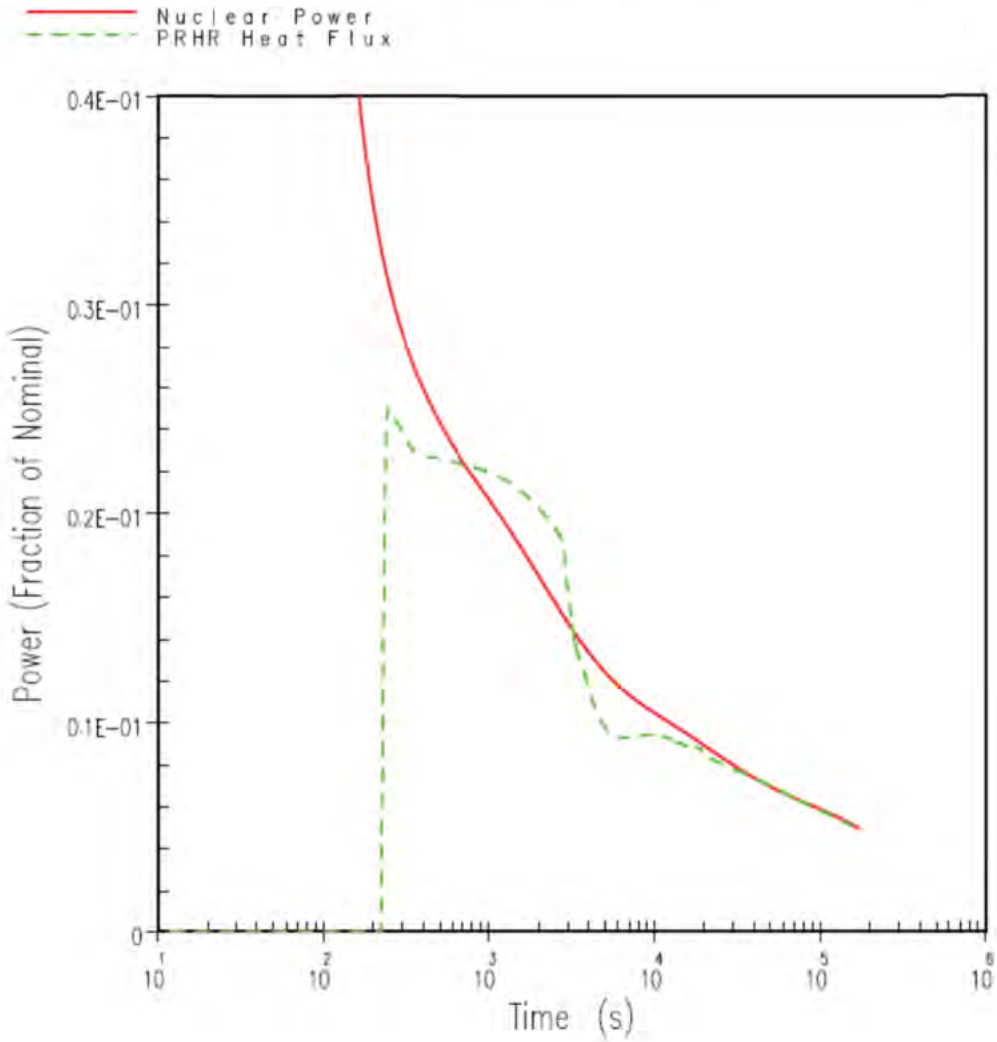
PTN DEP 3.2-1

Figure 19E.4.10-1R Shutdown Temperature Evaluation, RCS Temperature



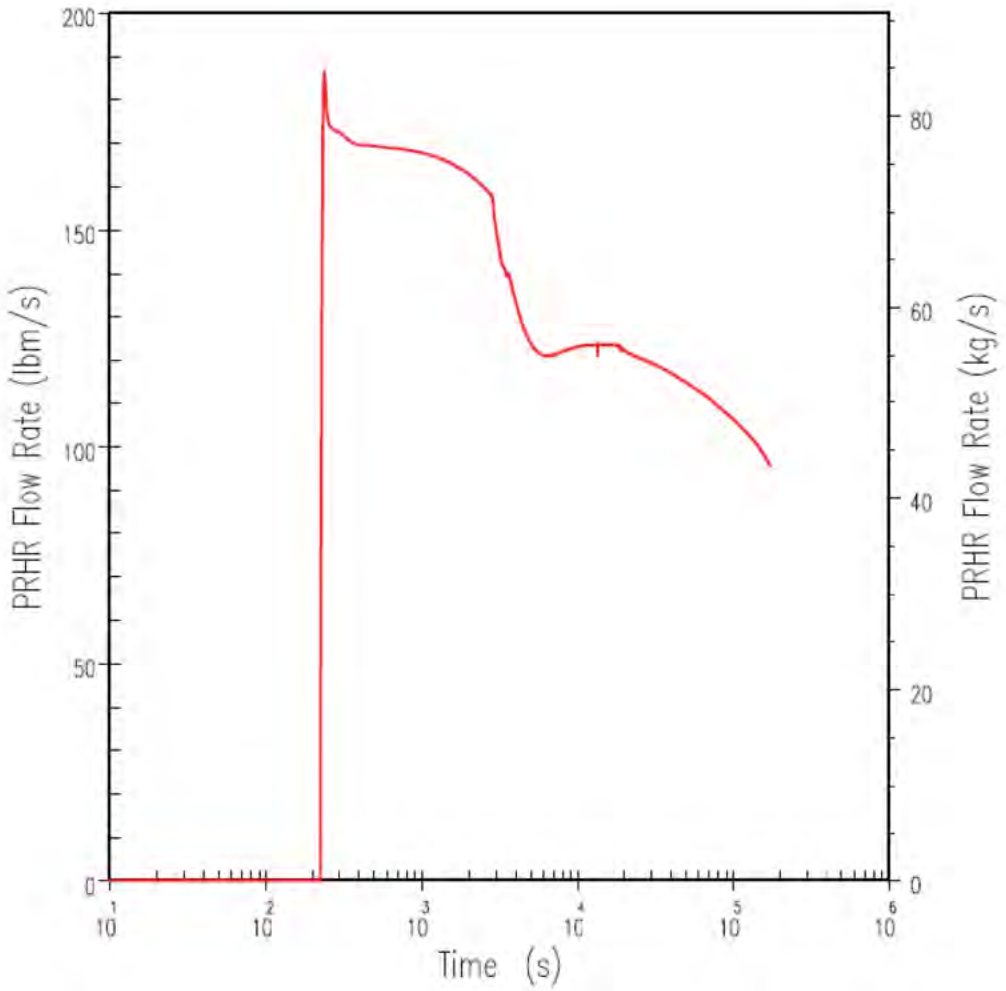
PTN DEP 3.2-1

Figure 19E.4.10-2R Shutdown Temperature Evaluation, PRHR Heat Transfer



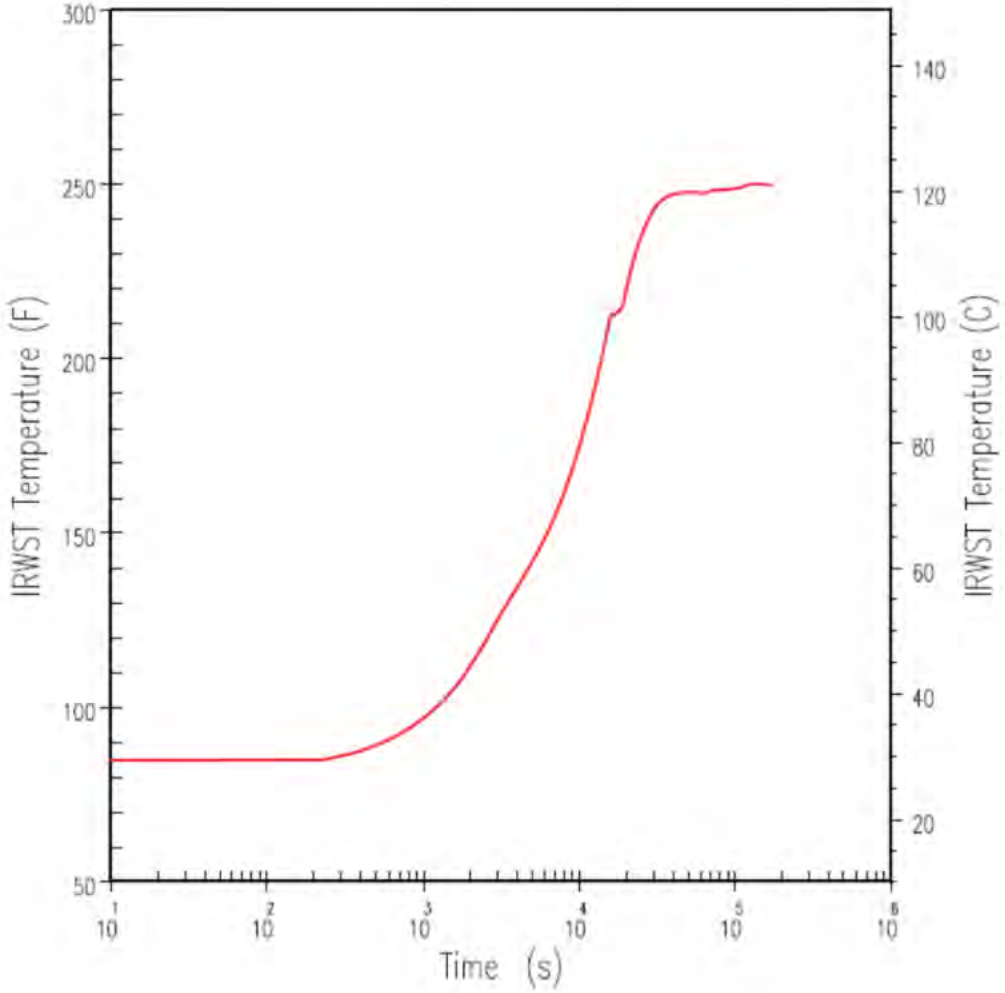
PTN DEP 3.2-1

Figure 19E.4.10-3R Shutdown Temperature Evaluation, PRHR Flow Rate



PTN DEP 3.2-1

Figure 19E.4.10-4R Shutdown Temperature Evaluation, IRWST Heatup



APPENDIX 19F MALEVOLENT AIRCRAFT IMPACT

This section of the referenced DCD is incorporated by reference with no departures or supplements.