UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 11, 2011

Mr. David A. Heacock
President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: NORTH ANNA POWER STATION, UNIT NOS. 1 AND 2 – TECHNICAL EVALUATION OF RESTART READINESS DETERMINATION PLAN (TAC NOS. ME7254 AND ME7255)

Dear Mr. Heacock:

By letter dated September 17, 2011, as supplemented by letters dated September 27, 2011 (two); October 3, 2011 (two), October 10, 2011, October 12, 2011, October 17, 2011, October 18, 2011 (two), October 20, 2011, October 25, 2011, October 28, 2011 (two), and October 31, 2011 (two), November 3, 2011, November 4, 2011, and November 7, 2011, Virginia Electric and Power Company (VEPCO, the licensee), submitted a summary report of the plant response to an earthquake centered near Mineral, Virginia, which occurred on August 23, 2011, for North Anna Power Station (NAPS), Units 1 and 2. The report also included a restart readiness determination plan. In the letter dated September 17, 2011, VEPCO stated that the earthquake exceeded the spectral and peak ground accelerations for the Operating Basis and Design Basis Earthquakes ("OBE" and "DBE", respectively) for NAPS, Units 1 and 2. More specifically, the recorded response spectra at the containment basemat which is founded on rock, in the range of frequencies most damaging to structures (e.g., 2 to 10 Hertz), did not exceed the NAPS DBE in the East-West direction, and only exceeded, on average, the North-South direction by about 12 percent and the vertical direction by about 21 percent.

In that letter, VEPCO also requested the concurrence of the U.S. Nuclear Regulatory Commission (NRC, the Commission) to restart North Anna, Units 1 and 2, upon completion of certain remaining near-term items. This request was made pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 100 Appendix A, Section V(a)(2), which requires a demonstration to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.

By letter dated September 30, 2011, the NRC issued Confirmatory Action Letter (CAL) No. 2-2011-001 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML11273A078), confirming your commitment that NAPS, Units 1 and 2, will not enter Modes 1-4 (as defined in the facility technical specifications), until the Commission has completed its review of the request for restart, performed confirmatory inspections, and completed its safety evaluation review.

The NRC staff has completed its review of the NAPS restart readiness determination plan and VEPCO's plans for the seismic evaluation of future plant modifications, including new and replacement equipment, as documented in its letter dated November 4, 2011. In that letter, VEPCO committed to include the seismic ground acceleration and derived In-structure

Response Spectra from both the existing DBE and the August 23, 2011, earthquake in any future seismic analysis to determine the maximum bounding design values for future modifications. This commitment will be documented in the NAPS Updated Final Safety Analysis Report. In addition, the NRC staff has performed confirmatory inspections and completed its technical evaluation.

The NRC staff has concluded that VEPCO has acceptably demonstrated that no functional damage has occurred to those features necessary for continued operation, and that NAPS can be operated, without undue risk to the health and safety of the public. The NRC also finds VEPCO's commitment for future plant modifications reasonable and acceptable.

Further, VEPCO has provided the information requested by the NRC to support its evaluation, as discussed in CAL 2-2011-001 of September 30, 2011. Therefore, the NRC has concluded that VEPCO has satisfactorily completed all commitments as stated in the September 30, 2011, CAL.

The basis for the NRC's determination is detailed in the enclosed technical evaluation.

Sincerely,

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Docket Nos. 50-338 and 50-339

Enclosure:
As stated

cc w/encl: Listserv

Response Spectra from both the existing DBE and the August 23, 2011, earthquake in any future seismic analysis to determine the maximum bounding design values for future modifications. This commitment will be documented in the NAPS Updated Final Safety Analysis Report. In addition, the NRC staff has performed confirmatory inspections and completed its technical evaluation.

The NRC staff has concluded that VEPCO has acceptably demonstrated that no functional damage has occurred to those features necessary for continued operation, and that NAPS can be operated, without undue risk to the health and safety of the public. The NRC also finds VEPCO's commitment for future plant modifications reasonable and acceptable.

Further, VEPCO has provided the information requested by the NRC to support its evaluation, as discussed in CAL 2-2011-001 of September 30, 2011. Therefore, the NRC has concluded that VEPCO has satisfactorily completed all commitments as stated in the September 30, 2011, CAL.

The basis for the NRC's determination is detailed in the enclosed technical evaluation.

Sincerely,

/RA/
Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Docket Nos. 50-338 and 50-339

Enclosure:
As stated

cc w/encl: Listserv

DISTRIBUTION:

LPL2-1 R/F	RidsNrrDeEvib Resource	RidsNrrLAJBurkhardt Resource
Public	RidsNrrDorlDpr Resource	RidsNrrPmNorthAnna Resource
RidsAcrsAcnw_MailCTR	RidsNrrDorlLpl2-1 Resource	RidsOgcRp Resource
RidsNrrDeEeeb Resource	RidsNrrDraAfpb Resource	RidsRgn2MailCenter Resource
RidsNrrDeEicb Resource	RidsNrrDraApla Resource	MKhanna, NRR
RidsNrrDeEmcb Resource	RidsNrrDssSbpb Resource	BMartin, NRR
RidsNrrDeEpnb Resource	RidsNrrDssScvb Resource	PBoyle, NRR
RidsNrrDeEptb Resource	RidsNrrDssSnpb Resource	CGratton, NRR
RidsNrrDeEsgb Resource	RidsNrrDssSrxb Resource	PLambert, NRR

*via memo; **via email

ADAMS Accession Nos. Package ML11308B404, Letter ML11308B405, SE ML1130B406

OFFICE	NRR/DORL/LPL2-1/PM	NRR/DORL/LPL2-1/PM	NRR/DORL/LPL2-2/LA	NRR/DE/EICB/BC	NRR/DE/EMCB/BC	NRR/DE/EVIB/BC
NAME	RMartin	PBoyle	JBurkhardt	GWilson**	KManoly**	HGonzalez*
DATE	11/11/2011	11/8/2011	11/8/2011	11/1/2011	11/10/2011	11/3/2011
OFFICE	NRR/DE/EEEB/BC	NRR/DE/ESGB/BC	NRR/DR/EPNB/BC	NRR/DE/EPTB/BC	NRR/DRA/AFPB/BC	NRR/DRA/APLA/BC
NAME	JAnderson**	VCusumano**	TLupold**	AMcMurtray**	AKlein*	DHarrison**
DATE	10/27/2011	11/1/2011	11/3/2011	11/1/2011	10/31/2011	10/5/2011
OFFICE	NRR/DSS/SBPB/BC	NRR/DSS/SCVB/BC	NRR/DSS/SNPB/BC	NRR/DSS/SRXB/BC	RII/DRP/PRB5/BC	NRR/DORL/BC
NAME	GCasto**	RDennig*	AMendiola**	AUlses**	GMcCoy**	MKhanna
DATE	11/4/2011	10/21/2011	10/24/2011	10/13/2011	11/11/2011	11/11/2011
OFFICE	NRR/DORL/D	OGC	NRR/D			
NAME	MEvans	EWilliamson**	ELeeds			
DATE	11/11/2011	11/10/2011	11/11/2011			

OFFICIAL RECORD COPY

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

TECHNICAL EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

Related to Plant Restart after the Occurrence of an Earthquake Exceeding the Level of the Operating Basis and Design Basis Earthquakes

Virginia Electric and Power Company
North Anna Power Station, Unit Nos. 1 and 2
Renewed Facility Operating License Nos. NPF-4 and No. NPF-7
Docket Nos. 50-338 and 50-339

November 11, 2011

NORTH ANNA POWER STATION, UNITS 1 AND 2

TECHNICAL EVALUATION RELATED TO PLANT RESTART AFTER THE OCCURRENCE OF AN EARTHQUAKE EXCEEDING THE LEVEL OF THE OPERATING BASIS AND DESIGN BASIS EARTHQUAKES

EXECUTIVE SUMMARY

On August 23, 2011, with the North Anna Power Station (NAPS), Units 1 and 2, operating at 100 percent power, the site experienced ground motion from a seismic event (a Magnitude 5.8 earthquake reported by the U.S. Geological Survey) in Mineral, Virginia, approximately 10 miles from NAPS. Shortly following the earthquake, both the Unit 1 and Unit 2 reactors tripped, and there was a loss of offsite power to the station. Following the earthquake, both units were stabilized, taken to a safe shutdown condition, and offsite power was restored. During the loss of offsite power, the four emergency diesel generators along with the one alternate alternating current (AC) diesel generator were activated to provide onsite AC power.

Subsequent analysis indicated that the spectral and peak ground accelerations for the Operating Basis and Design Basis Earthquakes (OBE and DBE, respectively) for NAPS were exceeded at certain frequencies for a short period of time.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR), Appendix A to Part 100, Section V(a)(2), a nuclear power plant is required to be shut down when the vibratory ground motion exceeds that of the OBE. In addition, the regulations state that "prior to resuming operations, the licensee will be required to demonstrate to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public."

Since the August 23, 2011, earthquake resulted in ground accelerations greater than what was assumed in the design of the NAPS, the regulations, as addressed above, required the NAPS units to be shut down and to remain shut down until the licensee for NAPS demonstrated to the U.S. Nuclear Regulatory Commission (NRC) that no functional damage occurred to those features necessary for continued operation.

To further support these requirements, the NRC issued Confirmatory Action Letter (CAL) No. 2-2011-001 to the licensee of NAPS confirming the licensee's commitment that the reactors at NAPS, Units 1 and 2, will not be restarted until the NRC has completed its review and authorized continued operation.

To demonstrate that no functional damage occurred as a result of the earthquake and that it was safe to operate the facility without undue risk to the health and safety of the public, the licensee performed a number of inspections, tests, and analyses, consistent with EPRI NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake." In addition, the licensee also performed additional testing and inspections not included in the EPRI guidelines and some of these additional tests and inspections were the result of questions raised by the NRC staff.

The NRC staff's assessment utilized the guidance provided in Regulatory Guide (RG) 1.167, "Restart of a Nuclear Power Plant Shut Down by a Seismic Event," which endorses, with

exceptions, the Electric Power Research Institute's (EPRI's) NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake."

Following the earthquake, the NRC dispatched an Augmented Inspection Team (AIT) to NAPS to better understand the event and the licensee's response. The team's findings included: (1) operators responded to the event in accordance with established procedures and in a manner that protected public health and safety; (2) the ground motion from the earthquake exceeded the plant's licensed design basis; (3) no significant damage to the plant was identified; (4) safety system functions were maintained; and (5) some equipment issues were experienced. Overall, the team concluded that the event did not adversely impact the health and safety of the public. Safety limits were not approached and there was no measurable release of radioactivity associated with the event. A report summarizing the AIT findings was published on October 31, 2011.

The NRC also sent a team of inspectors to the NAPS to provide an assessment of the licensee's inspection and testing program and the licensee's readiness for restart. Overall, this team concluded that the licensee performed adequate inspections, walkdowns, and testing to ensure that safety-related structures, systems, and components have not been adversely affected by the August 23, 2011, earthquake. The NRC's independent inspections of plant equipment, observation of surveillance testing, and review of completed test data, calculations, root cause evaluations, and documents associated with the station's corrective action and work order programs confirmed the operability and functionality of plant structures, systems, and components.

In addition to the on-site inspection activities, the NRC performed an independent technical review of the information submitted by the licensee to demonstrate that no functional damage occurred at NAPS as a result of the August 23, 2011, earthquake. The NRC's evaluation included reviews of the actions taken by the licensee to demonstrate that no functional damage has occurred, as a result of the earthquake, to those features necessary for continued operation, in accordance with 10 CFR Part 100, Appendix A.

There was some earthquake-related damage to non-safety-related equipment observed at NAPS; however, this damage was considered minor (i.e., it was not functional damage that would preclude safe operation of the facility). In addition, there were some non-earthquake-related issues identified as a result of the inspections performed. These issues are being addressed through established licensee and NRC processes to ensure they are adequately addressed without undue risk to the health and safety of the public.

In summary, the NRC concludes that the licensee acceptably demonstrated that no functional damage occurred at NAPS to those features necessary for continued operation, and that NAPS, Units 1 and 2, can be operated without undue risk to the health and safety of the public.

Although the NRC staff concludes that NAPS can be safely restarted, the licensee identified several activities (inspections and tests) that will be performed as part of the restart process. The NRC will monitor the startup of NAPS to confirm that the plant can be safely operated.

In addition to these start-up activities, several long-term action items were identified by the licensee. These long-term action items include those identified in Section 6.3 of EPRI NP-6695 and changes to the NAPS Updated Final Safety Analysis Report. These long-term commitments will be documented in CAL No. NRR-2011-002, and are unrelated to the NRC's conclusion that the licensee has demonstrated that no functional damage occurred to the NAPS and that it may be safely restarted.

NORTH ANNA POWER STATION, UNIT NOS. 1 AND 2

TECHNICAL EVALUATION RELATED TO PLANT RESTART AFTER THE OCCURRENCE OF AN EARTHQUAKE EXCEEDING THE LEVEL OF THE OPERATING BASIS AND DESIGN BASIS EARTHQUAKES

TABLE OF CONTENTS

1.0 INTRODUCTION 1

1.1 NRC Inspections 2

1.2 Regulatory Evaluation 4

2.0 SEISMOLOGY 5

2.1 August 23, 2011, Mineral VA Earthquake and its Tectonic Background 6

2.2 Seismic Impact to North Anna Nuclear Power Plant 7

2.3 Seismic Instrumentation 14

2.4 Conclusion 18

3.0 DESIGN OF STRUCTURES, SYSTEMS, AND COMPONENTS 18

3.1 Piping and Nondestructive Examination 18

3.1.1 Introduction 18

3.1.2 Piping Inspection and Nondestructive Examination 19

3.1.3 Buried Piping 22

3.1.4 Pressure Testing of Piping 26

3.1.5 Verification of Existing Flaws 28

3.1.6 Pipe Stress Analyses Verification 30

3.1.7 Pipe Support Verification 32

3.1.8 Leak-Before-Break Analysis 33

3.1.9 Conclusion 34

3.2 Mechanical and Civil Engineering 34

3.2.1 Description of Licensee Evaluation/Actions 34

3.2.2 NRC Staff's Evaluation of Licensee Evaluation/Actions 35

3.2.3 Conclusion 51

3.3 Snubbers 51
3.3.1 Description of the Licensee's Evaluation and Actions 51
3.3.2 NRC Staff Evaluation of Licensee Evaluation and Actions 54
3.3.3 Conclusion 56
4.0 NUCLEAR FUEL 56
4.1 Nuclear Fuel Performance 56
4.1.1 Fuel Assembly Damage Resulting from Seismic Event 60
4.1.2 Future Performance of Fuel Currently Used at NAPS 64
4.1.3 Applicability of Unit 2 Fuel Inspections to Unit 1 Fuel Assemblies 65
5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS 67
5.1 Reactor Systems 67
5.1.1 Description of Licensee's Evaluation and Actions 67
5.1.2 NRC Staff Evaluation 69
5.1.3 Conclusion 69
5.2 Steam Generators 70
5.2.1 Description of Licensee's Evaluation and Actions 70
5.2.2 NRC Staff Evaluation 72
5.2.3 Conclusion 73
5.3 Reactor Vessel Internals 73
5.3.1 Description of Licensee Evaluations/Actions 73
5.3.2 NRC Staff Evaluation of RVI Margin Assessment 74
5.3.3 NRC Staff Evaluation of RVI Inspection Efforts 77
5.3.4 Conclusion 81
5.4 Pumps and Valves Inservice Test Program 82
5.4.1 Description of the Licensee Evaluation/Actions 82
5.4.2 NRC Staff Evaluation 84
5.4.3 Conclusion 86

6.0 CONTAINMENT AND HEATING, VENTILATION AND AIR CONDITIONING (HVAC) SYSTEMS 87

6.1 Containment Structure 87

6.2 Containment Isolation Valves 87

6.3 Containment Leakage Integrity 88

6.4 Heating, Ventilation and Air Conditioning (HVAC) 89

6.4.1 Emergency Core Cooling System (ECCS) Pump Room Exhaust Air Cleanup System (PREACS) 89

6.4.2 Control Room 90

7.0 INSTRUMENTATION AND CONTROLS SYSTEMS 90

7.1 Physical Inspections and Tests Conducted to Identify Apparent Damage and Potential Loose Electrical Connections 91

7.2 Resolution of Instrumentation Performance Anomalies Observed During the Seismic Event 92

7.3 Performance of Westinghouse 7300 Series Protection and Control Boards 92

7.4 Performance Tests and Surveillances Conducted to Demonstrate "No Functional Damage" 93

7.5 Evaluation of Key Non-Technical Specification I&C Systems and Components 94

7.6 I&C Equipment Seismic Qualification Margin 95

7.7 NRC Staff Evaluation 98

7.8 Instrumentation and Control Conclusions 98

8.0 ELECTRICAL SYSTEMS 99

8.1 Offsite Power System 99

8.2 Onsite Power System 101

8.3 Electrical Systems Conclusion 106

9.0 AUXILIARY SYSTEMS 106

9.1 Balance of Plant Systems 106

9.1.1 Licensee's Assessment 106

9.1.2 NRC Staff Evaluation 106
9.1.3 Conclusion 107
9.2 Emergency Diesel Support Systems 107
9.2.1 Emergency Diesel Generator Fuel-Oil Storage and Transfer System 108
9.2.2 Emergency Diesel Generator Cooling Water System 109
9.2.3 Emergency Diesel Generator Starting Air System 109
9.2.4 Emergency Diesel Generator Lubrication System 110
9.2.5 Emergency Diesel Generator Ventilation and Combustion Air Intake and Exhaust System 110
9.3 Fire Protection 111
9.3.1 Description of Licensee Evaluation/Actions 111
9.3.2 NRC Staff Evaluation of Licensee Evaluation/Actions 115
9.3.3 Conclusion 115
10.0 RISK INSIGHTS 116
10.1 Description of Licensee Evaluations/Actions 116
10.2 NRC Staff's Evaluation of Licensee Evaluation/Actions 116
11.0 CONCLUSION 116
12.0 REFERENCES 117

TECHNICAL EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO PLANT RESTART AFTER THE OCCURRENCE OF AN EARTHQUAKE

EXCEEDING THE LEVEL OF THE OPERATING BASIS AND DESIGN BASIS EARTHQUAKES

VIRGINIA ELECTRIC AND POWER COMPANY

NORTH ANNA POWER STATION, UNIT NOS. 1 AND 2

RENEWED FACILITY OPERATING LICENSE NOS. NPF-4 AND NO. NPF-7

DOCKET NOS. 50-338 AND 50-339

1.0 INTRODUCTION

By letter dated September 17, 2011 (Reference 1), as supplemented by letters dated September 27, 2011 (two), October 3, 2011 (two), October 10, 2011, October 12, 2011, October 17, 2011, October 18, 2011 (two), October 20, 2011, October 25, 2011, October 28, 2011 (two), October 31, 2011 (two), November 3, 2011, November 4, 2011, and November 7, 2011 (References 2 through 20), Virginia Electric and Power Company (VEPCO, the licensee), submitted a summary report of the plant response to an earthquake centered near Mineral, Virginia, which occurred on August 23, 2011, for North Anna Power Station (NAPS), Units 1 and 2. The report also included a restart readiness determination plan. In the letter dated September 17, 2011, VEPCO indicated that the earthquake resulted in exceeding the spectral and peak ground accelerations for the Operating Basis and Design Basis Earthquakes ("OBE" and "DBE," respectively) for NAPS, Units 1 and 2. In that letter, VEPCO also requested the concurrence of the U.S. Nuclear Regulatory Commission (NRC, the Commission) to restart NAPS, Units 1 and 2, upon completion of the remaining near-term items identified in Enclosure 8 to its letter. This request was made pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 100, "Reactor Site Criteria," Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," Section V(a)(2), "*Determination of Operating Basis Earthquake*," which requires a demonstration to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public. This evaluation does not include a review of the Independent Spent Fuel Storage Installations (Docket Nos. 72-16 and 72-56), as those installations are separate from the plant features necessary for reactor operation.

By letter dated September 30, 2011 (Reference 21), the NRC Region II staff issued Confirmatory Action Letter (CAL) No. 2-2011-001, confirming the NRC's understanding that NAPS, Units 1 and 2, will not enter Modes 1-4 (as defined in the facility technical specifications), until the Commission has completed its review of the request for restart, performed confirmatory inspections, and issued its technical evaluation. The NRC staff has completed its review of the

NAPS restart readiness determination plan, and has concluded that the licensee has acceptably demonstrated that no functional damage has occurred to those features necessary for continued operation, and that NAPS, Units 1 and 2, can be operated, without undue risk to the health and safety of the public. The NRC's evaluation of the licensee's restart request, and the basis for its conclusion, is provided herein.

1.1 NRC Inspections

The NRC dispatched an Augmented Inspection Team (AIT) to NAPS, Units 1 and 2, on August 30, 2011, to evaluate the licensee's response to the seismic event of August 23, 2011, because it was unclear whether the ground motion from the earthquake had exceeded the NAPS licensed design basis, and because of the potential safety ramifications from the failure of the 2H emergency diesel generator and a loss of offsite power. The AIT was established in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program," and implemented using Inspection Procedure 93800, "Augmented Inspection Team."

The objectives of the AIT were to: (1) collect, analyze and document factual information and evidence relating to the event; (2) assess the licensee's actions and plant response during the event; (3) identify any generic issues; (4) conduct an independent extent of condition review; and (5) support a final determination of the risk significance of the event.

The AIT's findings included: (1) operators responded to the event in accordance with established procedures and in a manner that protected public health and safety; (2) the ground motion from the earthquake exceeded the plant's licensed design basis; (3) no significant damage to the plant was identified; (4) safety system functions were maintained; and (5) some equipment issues were experienced.

The team evaluated the event to determine if any issues should be considered on a generic basis for other facilities. The team identified two potential issues in the areas of seismic monitoring instrument location and seismic monitoring equipment performance.

Several specific issues related to equipment performance warranted follow-up. These included: (1) the 2H EDG developed a cooling water leak necessitating its shutdown; (2) operators observed frequency oscillations affecting the 1J EDG that appeared to approach Technical Specification (TS) limits; (3) some functions of the control room seismic alarm panel were lost during the earthquake; (4) seismic instrumentation, data collection and operator training issues were revealed; (5) missing cooling water orifice plates were identified on the 1J and 2J EDGs; (6) an auxiliary feedwater (AFW) pump trouble alarm was unexpected during the event; and (7) some anomalies were observed affecting some safety-related instrumentation during the event. These issues were documented as unresolved items in the AIT report.

A public exit meeting between the licensee and NRC staff was held on October 3, 2011. The inspection report was published on October 31, 2011 (Reference 30).

Overall, the AIT concluded that the event did not adversely impact the health and safety of the public. Safety limits were not approached and there was no measurable release of radioactivity associated with the event.

Following completion of the AIT inspection, the NRC sent another team of inspectors to the NAPS to assess the licensee's inspection program and readiness for restarting NAPS, Units 1 and 2, which commenced on October 5, 2011. The Restart Readiness Inspection followed Inspection Procedure 92702, "Follow-up on Traditional Enforcement Actions Including Violations, Deviations, Confirmatory Action Letters, Confirmatory Orders, and Alternative Dispute Resolution Confirmatory Orders." Supplemental guidance to this inspection procedure was provided by the Electric Power Research Institute (EPRI) Report NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake"; NRC Regulatory Guide (RG) 1.166, "Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Post-Earthquake Actions" (Reference 24); RG 1.167, "Restart of a Nuclear Power Plant Shut Down by a Seismic Event" (Reference 23); the AIT report; and input from NRC subject matter experts.

The objectives of the Restart Readiness Inspection included the following: (1) assess the licensee's inspection process to ensure damage attributable to the event would be identified, (2) ensure the underlying causes of the dual unit reactor trip and failure of the 2H diesel generator were properly identified and the appropriate corrective actions were assigned, (3) review how licensee-identified issues were evaluated and dispositioned, (4) observe and review licensee testing of plant systems and selected surveillance test data packages completed since the seismic event, (5) review the tracking and completion of the licensee's committed actions, and (6) support a final determination as to the overall condition of the plant to support restart.

Following the completion of the onsite inspection activities on October 14, 2011, several issues related to equipment performance were addressed through continued dialogue with the licensee. These issues included: (1) ensuring that any movement of the reactor vessel supports of both units was within design limits, (2) determining if material conditions identified by the inspection team were seismic-related and properly addressed based on their safety significance and potential impact on system operation, (3) assessing the thoroughness of the licensee's selected initial inspections, and (4) evaluating the significance of the lack of a Unit 1 pipe tunnel penetration seal between the main steam valve house and the turbine-driven auxiliary feedwater (TDAFW) pump room.

Although the resolution of these issues will be published in the forthcoming Restart Readiness Inspection Team's inspection report, the Restart Readiness Team concluded that the licensee performed adequate inspections, walkdowns and testing to ensure that safety-related structures, systems, and components (SSCs) had not been adversely affected by the August 23, 2011, earthquake. The NRC's independent inspections of plant equipment, observation of surveillance testing, and review of completed test data, calculations, root cause evaluations and documents associated with the station's corrective action and work order programs confirmed the operability and functionality of plant SSCs. The Restart Readiness Team reviewed the unresolved items from the AIT and determined that corrective actions had been completed such that the systems were operable to support the restart of NAPS, Units 1 and 2.

An exit meeting between the licensee and NRC staff was held on November 7, 2011. The final results of the Restart Readiness Inspection Team will be documented in an inspection report, which will be made publicly available in the Agencywide Documents Access and Management System (ADAMS).

1.2 Regulatory Evaluation

The following regulatory requirements and guidance were used in the evaluation of the licensee's restart readiness determination.

Appendix A to 10 CFR Part 100, Section V(a)(2) states, in part, that:

> If vibratory ground motion exceeding that of the Operating Basis Earthquake occurs, shutdown of the nuclear power plant will be required. Prior to resuming operations, the licensee will be required to demonstrate to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.

The NAPS Updated Final Safety Analysis Report (UFSAR), Section 3.7.4.6, "Use of Data from Seismic Instrumentation," has similar words, as it requires the licensee to demonstrate to the NRC that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.

NRC Regulatory Guide (RG) 1.167, "Restart of a Nuclear Power Plant Shut Down by a Seismic Event," March 1997 (Reference 23), endorses Electric Power Research Institute (EPRI) report NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake," December 1989, with exceptions. This report provides a methodology for conducting inspections and tests of nuclear power plant equipment and structures at a nuclear power plant that has been shut down in response to a seismic event. As described previously, 10 CFR Part 100 requires a plant shutdown if vibratory ground motion in excess of the OBE has occurred. Since the DBE levels are anchored at higher ground motion magnitudes than the OBE, it follows, that if the DBE has been exceeded the OBE has also been exceeded and the plant must shut down. EPRI report NP-6695, as endorsed by RG 1.167, provides actions based on a damage assessment scale to be taken once it has been determined that the OBE was exceeded. This scale is independent of the OBE/DBE classification. Further, EPRI NP-6695 discusses actions to be taken in the event that DBE floor response spectra have been exceeded. Thus, in accordance with RG 1.167, EPRI NP-6695 provides guidance acceptable to the NRC staff for exceedances of both OBE and DBE, with the exceptions noted in the RG. The licensee stated in its letter dated September 17, 2011, that the proposed restart readiness assessment plan is based, in part, on the guidance contained in RG 1.167.

NRC RG 1.166, "Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Post-Earthquake Actions," dated March 1997 (Reference 24), provides guidance acceptable to the NRC staff for a timely evaluation after an earthquake of the recorded instrumentation data and for determining whether a shutdown is required. It references portions of EPRI report NP-6695, with conditions. The licensee stated in its letter dated September 17, 2011, that the proposed restart readiness assessment plan is based, in part, on the guidance contained in RG 1.166.

NRC Generic Letter (GL) 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE)," dated June 28, 1991 (Reference 25), requested that "each licensee perform an individual plant examination of external events to identify vulnerabilities, if any, to severe accidents and report the results together with any licensee determined improvements and

corrective actions to the Commission." The external events considered in the IPEEE program include seismic events, internal fires, high winds, and floods. The primary goal of the IPEEE program was for each licensee to identify plant-specific vulnerabilities to severe accidents, if any, and to report the results, with any licensee-proposed improvements and corrective actions, to the NRC. In the NAPS IPEEE effort, the plant was evaluated to a median-centered ground response spectrum shape anchored to 0.3 g peak ground acceleration. Calculations were performed to determine the high-confidence-of-low-probability-of-failure (HCLPF) capacities of equipment and structures. A small number of structures and components were found to have HCLPF capacities below 0.3 g. By letter dated June 5, 2000 (Reference 26), the NRC documented its review of the NAPS IPEEE, and concluded that NAPS had met the intent of Supplement 4 to GL 88-20.

International Atomic Energy Agency (IAEA) Safety Reports Series No. 66, "Earthquake Preparedness and Response for Nuclear Power Plants," provides guidance to international operating organizations in the formulation of an earthquake preparedness and response program, including aspects relating to the possibility of hidden damage after a safe shutdown earthquake (SSE) (DBE in the NAPS terminology).

NRC Inspection Manual Part 9900, "Operability Determinations and Functionality Assessments for Resolution of Degraded or Non Conforming Conditions Adverse to Quality or Safety," provides more detailed guidance for determinations of operability and resolution of degraded or nonconforming conditions. Licensees were alerted to the latest revision to this guidance through the issuance of NRC Regulatory Issue Summary (RIS) 2005-20, Revision 1, "Revision to NRC Inspection Manual Part 9900 Technical Guidance, "Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," dated April 16, 2008 (Reference 27).

The NAPS UFSAR, including but not limited to, Sections 3.7, "Seismic Design," 3.8, "Design of Seismic Class 1 Structures," and 3.10, "Seismic Design of Class 1 Instrumentation and Electrical Equipment," provides site-specific seismic design requirements for safety-related SSCs.

2.0 SEISMOLOGY

The design basis of safety features for each nuclear power plant must take into account the potential effects of two levels of earthquake motion. The greater earthquake motion is based on an evaluation of the maximum earthquake potential considering regional and local geology and seismology and the specific characteristics of local subsurface material. This earthquake motion is designated as the SSE or, in the case of NAPS, the DBE. It is the DBE for which certain SSCs necessary for safe shutdown are designed to remain functional. The lesser earthquake motion represents an earthquake event that has a reasonable chance of occurring during the life of the plant and is designated as the OBE. It is the OBE that produces the ground motion for which those features of the nuclear power plant necessary for continued operation are designed to remain functional. Appendix A to 10 CFR Part 100 requires that the design bases for earthquakes be determined through evaluation of the geologic and seismic history of the site and surrounding region. A determination is also required of the influences that result from human activities and from local site soil conditions. The largest earthquakes occurring in the site region must be assessed. An evaluation is required to determine whether faults in the site

region are active and could generate earthquakes large enough to be of significance to the earthquake design bases.

According to NAPS Updated Final Safety Analysis Report (UFSAR), Section 2.5, “Geology and Seismology,” the most significant earthquakes in the region of the station affecting its design occurred near the Richmond Basin in 1774 and near the Arvonia Syncline in 1875. These shocks and related zones of earthquake activity are both located within 50 miles of the site and are believed to be associated with faulting in their respective basin-like structures. For the purpose of establishing a DBE, it was assumed that an earthquake equal to the largest shock associated with the Arvonia Syncline might occur close to the site area. With the epicenter of a shock similar to the 1875 Arvonia earthquake shifted to the vicinity of the site, it was estimated that the maximum horizontal ground acceleration at the rock surface would be less than 0.12 g. Accordingly, the DBE for structures founded on rock was taken at 0.12 g for horizontal ground motion and two-thirds that value (0.08 g) for vertical ground motion. For structures founded on soil, the DBE was taken at 0.18 g for horizontal motion and 0.12 g for vertical motion. Seismic design for SSCs is described in NAPS UFSAR Section 3.7, “Seismic Design.”

2.1 August 23, 2011, Mineral VA Earthquake and its Tectonic Background

On August 23, 2011, a 5.8 moment magnitude scale (Mw) magnitude earthquake occurred near Mineral, Virginia. According to the U.S. Geological Survey (USGS), the earthquake occurred at a relatively shallow depth about 6 kilometers from the surface and was felt in the entire United States eastern coast area. Some chimney and structural damage to residential buildings was observed around the epicenter area. A number of aftershocks have occurred since the main shock, with the largest magnitude being a 4.5 Mw. There is no known fault source associated with the earthquake and aftershocks, but the USGS focal mechanism solution of the earthquake indicates that the earthquake was possibly associated with a reverse fault. Since there is no report on any existing fault in the area and no surface ruptures reported during the earthquake, the fault is assumed to be a blind reverse fault.

The earthquake and its aftershocks actually occurred inside an area seismic source zone called the Central Virginia Seismic Zone (CVSZ). The CVSZ has produced small and moderate earthquakes since at least the 18th century and magnitudes for some significant events since 1984 ranged from 4.0 to 4.6 with the depth between 5 and 8 km. The largest earthquake known to have occurred in the CVSZ before 2011 is a magnitude 5.0 mb (body wave magnitude) Goochland County event in 1875. CVSZ is determined in USGS Quaternary fault database as an “A” class seismic source, meaning that the CVSZ demonstrated Quaternary faulting of tectonic origin.

According to the USGS, the earthquake epicenter was located at 37.936° N, 77.933° W, approximately 18 km (11 miles) from the NAPS. The USGS’s estimate of Modified Mercalli Intensity is VI at the NAPS site. The USGS estimated that the August 23, 2011, earthquake produced a peak ground acceleration of 0.26 g at the NAPS site using ground motion prediction equations modified by intensity information obtained by the USGS. Since the fault is assumed to strike north or northeast, that places the seismogenic fault closer to the NAPS (< 18 km).

In the tectonic summary, the USGS indicates that the earthquake could not be causally associated with a currently mapped fault, but that it is originated from a reverse or compression fault with a north or northeast striking plane. Earthquake magnitude estimates for the August 23, 2011, event, range from 5.7 to 5.8 (Mw), which is dependent upon the calculation methodology used. According to the USGS, accurate estimates of the probable fault rupture geometry will not be understood until longer term studies have been completed. The recurrence interval for this event cannot be stated with any degree of certainty at this time.

The licensee indicated that the scientific community has not yet completed a full evaluation of the August 23, 2011, earthquake as of this time. VEPCO has been consulting with the Department of Geosciences at Virginia Polytechnic Institute and State University on this issue and will provide an update regarding any special ground motion effects by March 31, 2012. The NRC staff agrees that understanding the special ground motion effect is closely related to the knowledge on the seismic source fault, and concurs with the licensee's initiative in this regard.

2.2 Seismic Impact to North Anna Nuclear Power Plant

The operating licenses for these two units were issued in 1971. The licensee identified that the largest earthquake occurred along the Arvonia Syncline is the largest historical event and assumed it occurred near the site. Therefore, Modified Mercalli Intensity (MMI) VII associated with the earthquake was used in the original seismic design for both units. Based on that, two DBE ground motions were established. One is for SSCs located on top of rock, which is anchored at 0.12 g (horizontal), and 0.09 g (vertical), and the other is for SSCs located on top of soil, which is anchored at 0.18 g (horizontal) and 0.12 g (vertical). The vibration from the earthquake tripped both Units 1 and 2 at the site.

The North Anna nuclear power plant has seismometers located in Unit 1 Containment and Auxiliary buildings at different elevation levels, respectively. A comparison of seismic recordings inside the Unit 1 building at two elevation levels is listed in Table 1 and referred to in corresponding figures. However, all the seismometers are located on structures or systems, and none are located in the free surface in the free field, from which seismic recording can be exactly compared with SSEs. Since Unit 1 foundation is located directly on relatively hard rock with a shear wave velocity of 5000-6000 ft/second and the foundation basemat is relatively rigid, the recordings are considered approximate to the rock input motion from a damage assessment point of view. In comparing response spectrum calculated from the acceleration recordings, the licensee determined that both DBEs are exceeded and so are the DBEs at different elevation levels (see attached figures and table). However, acceleration time history recorded at the foundation level also indicates that the earthquake duration is quite short at about 3 seconds for the strongest component.

The licensee's calculated Cumulative Absolute Velocity (CAV) value 0.175 g-second indicates that the damage threshold 0.16 g-second specified in RG 1.166 was slightly exceeded. In addition, the licensee also calculated pseudo CAV values from the original design time histories, which are three component synthetic time histories. The licensee further noted that the CAV comparison was corroborated by the extensive walkdowns following EPRI NP-5966 guidelines, which did not identify significant damage to safety-related SSCs at the North Anna plant facility. Based on observations from inspections and examinations, the license conservatively

concluded that the earthquake intensity level is “1,” although all the evidence indicates that the level is actually “0.”

The NRC staff requested that the licensee provide the basis for VEPCO's use of the CAV criterion to explain the level of damage given that there was no seismic recording from instrumentation located on free surface in the free field since the CAV threshold is in general based on seismic recordings from free surface in the free field.

In response to the NRC staff’s question, the licensee responded that the North Anna Power Station is essentially situated on a rock site. It is a common practice for many US nuclear plants on rock sites to locate their seismic recorders at the top of the containment basemat, consistent with the commitments in the North Anna UFSAR Section 3.7.4.5. It is recognized that due to incoherency, there can be a reduction in the spectral values at the top of the containment basemat and the time-histories recorded at the basemat from an earthquake could be slightly lower than the free-field time-histories. However, the spectral reductions in large basemats due to incoherency effects are in the higher frequency range and are in the order of about 15 percent. Since recorded time-histories at the containment basemat from the August 23, 2011, earthquake contain significant low frequency content, the calculated CAV values would be expected to be at most 10 percent lower than the values that could be calculated from a free-field recorder.

The licensee concluded that the containment basemat at the North Anna site is a reasonable representation of the hard rock free-field data from the August 23, 2011, earthquake, and the CAV values calculated from the time-histories at the Containment basemat are considered reasonably accurate. The licensees further pointed out that this view was also shared by several industry experts who were peer reviewers of the licensee’s technical evaluation of the characterization of the August 23, 2011, earthquake.

The NRC staff agrees that for Unit 1, where most seismometers are installed, the foundation is situated on a relatively rigid hard rock, and therefore, the interaction between the structure and surrounding materials is much less than those structures locating on lower shear wave velocity soil. In addition, the design spectra at the top of the basemat are very close to the free-field SSE spectra in each of the three directions. Considering that incoherent and other potential reduction effects are relatively small, the NRC staff considers that the calculated CAV value from the structure founded seismometers to be a reasonable approximation from the standpoint of damage evaluation.

Table 1. NRC staff comparison between the observed ground motions recorded at Unit 1 and design motions at the same locations.

Structures (seismometers)	Elevation and Orientation	General Description	Key frequency exceedance of DBE	Largest difference between observed and DBE	Other seismometers
Unit 1 (Kinemetrics SMA-3) Figure 1	Basemat 216 ft in the N-S	Seismometer will record if exceeded design basis motion (5% damping)	Exceeded from 2.5 Hz and above, except at 8 Hz	100% at approximately 40 Hz and above	Engdahl scratch plate recordings exist; no exceedance at all recorded frequencies but no readings at 10.1 and 25.4 Hz, and conflict with Kinemetrics SMA-3 recordings
Unit 1 (Kinemetrics) Figure 1	Basemat 216 ft in the E-W	Seismometer will record if exceeded design basis motion (5% damping)	Exceeded at several frequency bands centered at 12, 16 and 30 Hz	24% at about 30 Hz	Engdahl scratch plates recordings exist with minor exceedance at 2,8, 12.7 , 16 and 25.4 Hz only
Unit 1 (Kinemetrics) Figure 2	Basemat 216 ft in the Vertical	Seismometer will record if exceeded design basis motion (5% damping)	Exceeded from 3 Hz and above	88% at 29 Hz	Engdahl scratch plates recordings exist with exceedance at 10.1 and 25.4 Hz only
Unit 1 (Kinemetrics) Figure 3	Containment elevation 291 ft in the N-S	Seismometer will record if exceeded design basis motion (5% damping)	Exceedance almost continuously from 1 to 3 Hz and 7.8 Hz and above	86% at 3 Hz	No Engdahl scratch plates readings
Unit 1 (Kinemetrics) Figure 3	Containment elevation 291 ft in the E-W	No exceedance at all the frequencies			No Engdahl scratch plates readings
Unit 1 (Kinemetrics) Figure 4	Containment elevation 291 ft in the vertical	Seismometer will record if exceeded design basis motion (5% damping)	Exceeded at 3-4 Hz, 5-10 Hz and 26 Hz and above	176 % at about 40 Hz	No Engdahl scratch plates readings

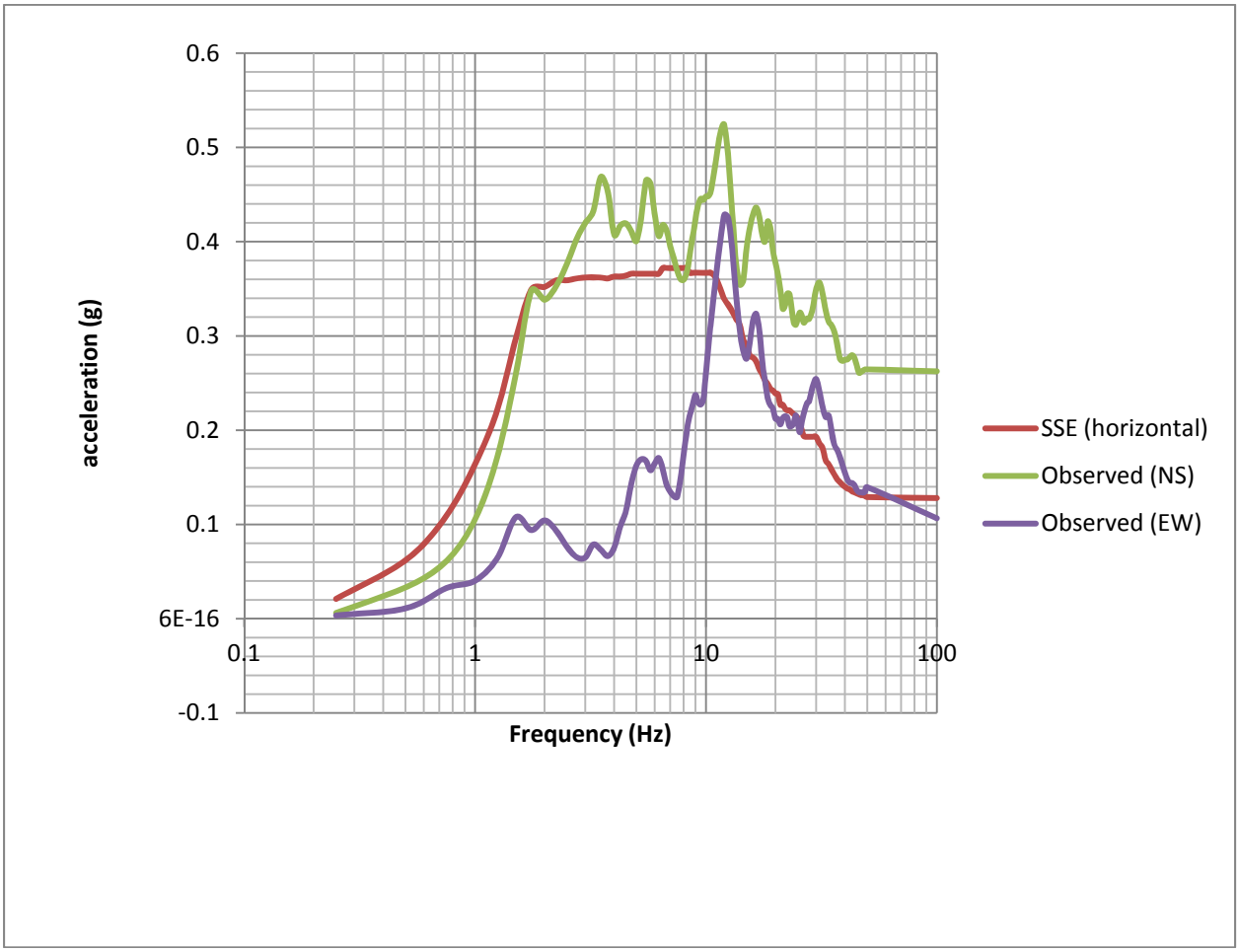
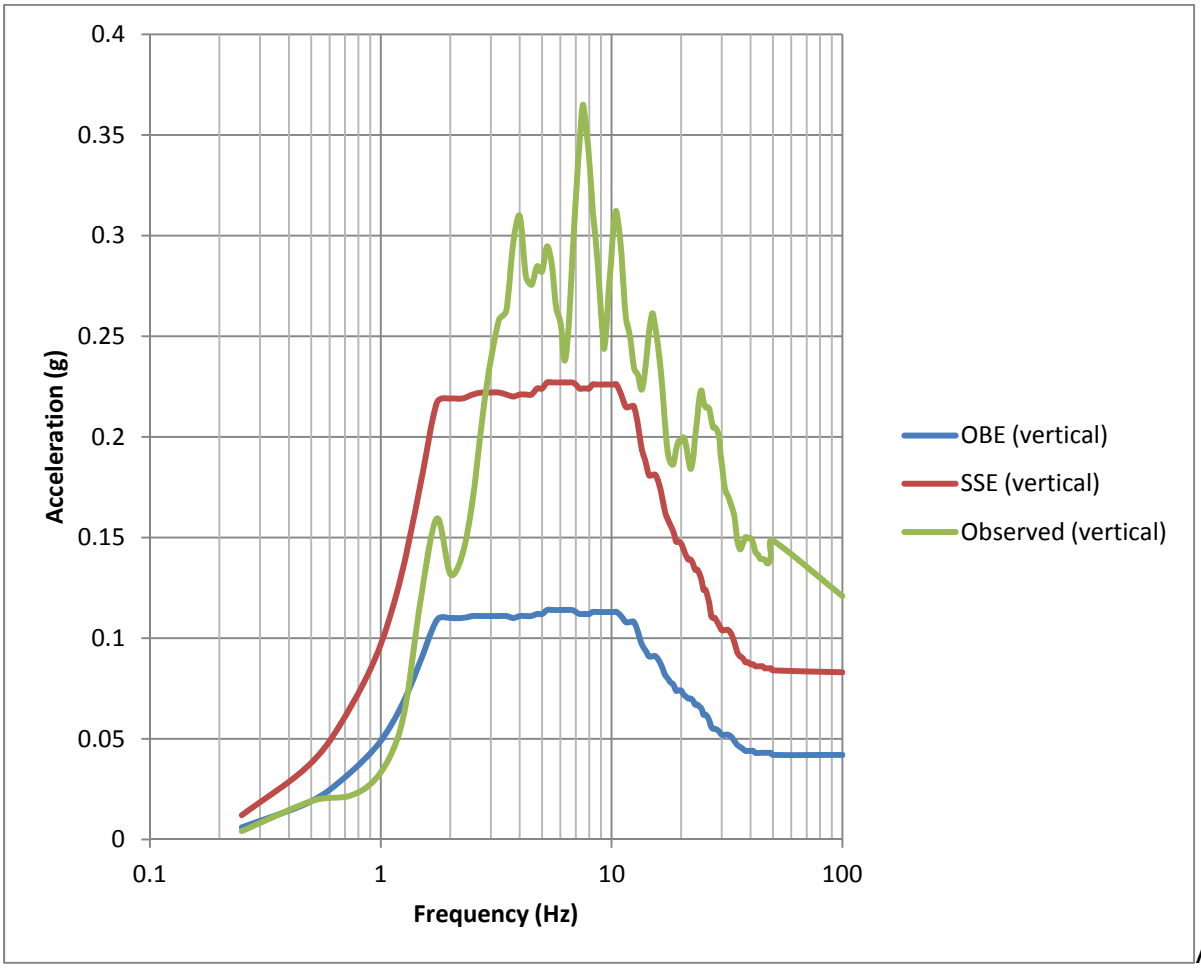


Figure 1. NRC staff comparison of horizontal ground motion at basemat floor level (216 ft elevation)



As

Figure 2. NRC staff comparison of vertical ground motion at basemat floor level (216 ft elevation)

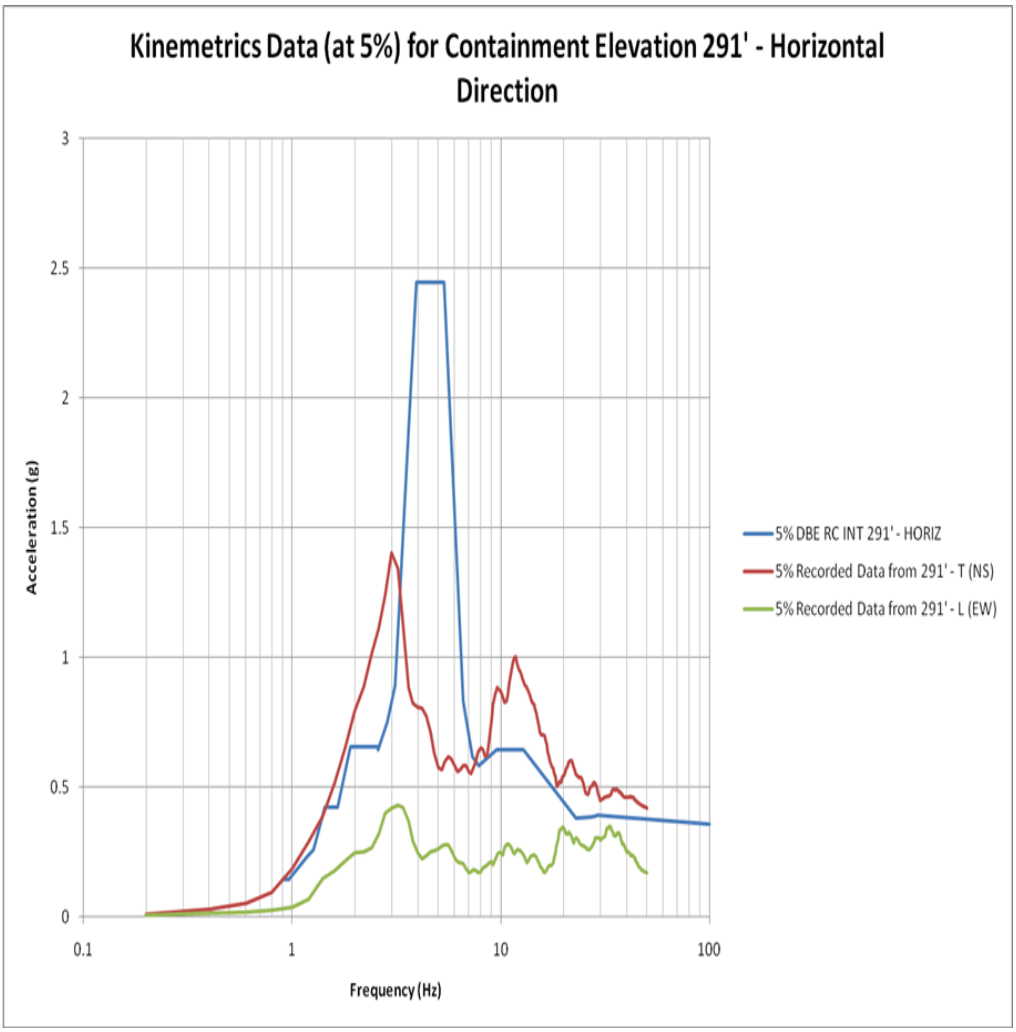


Figure 3. VEPCO's comparison of horizontal ground motion at operating deck (291 ft elevation)

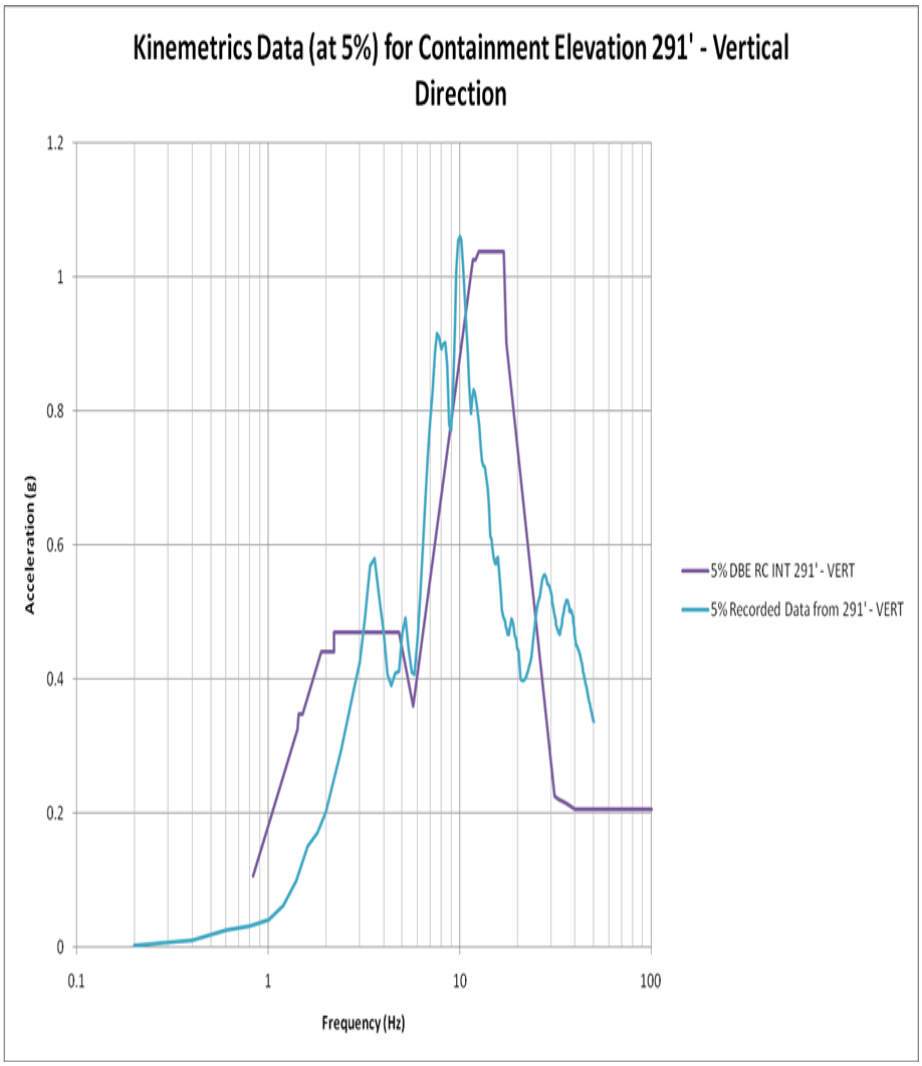


Figure 4. VEPCO's comparison of vertical ground motion at operating deck (291 ft elevation level)

2.3 Seismic Instrumentation

There are two types of seismometers, Engdahl and Kinemetrics, located at different elevation levels of Unit 1 Containment (Figure 5) and Auxiliary Buildings. The seismic monitors for both types of equipment at the Unit 1 basemat were connected to the seismic instrumentation panel located in the control room with indications of OBE and SSE exceedance (see Figure 5). During the earthquake, the annunciation panel lost power for about 8 seconds. Therefore, the plant operators were not informed about the panel annunciator. Based on the Augmented Investigation Team (AIT) Report, several issues regarding the seismometers and annunciation panel in the Main Control Room led the NRC staff to ask the following questions.

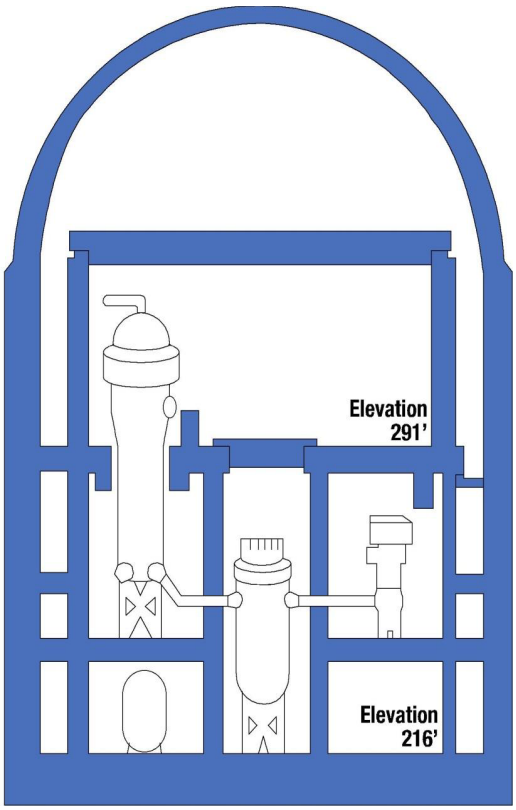


Figure 5. Locations of seismometers inside Unit 1 containment building as provided by VEPCO

According to RG 1.166, the nuclear power plant should have operable seismic instrumentation, including the computer equipment and software required to process the data within 4 hours after an earthquake. As stated in September 8, 2011, public meeting, however, there were no on-site resources at NAPS to interpret the instrumentation data and the time required for data interpretation using an outside vendor significantly exceeded 4 hours. Also, during the earthquake, there was no annunciation in the NAPS main control room that the design basis SSE was exceeded. Considering this operating experience, the NRC staff requested the licensee to discuss VEPCO's plan for modernization of the seismic instrumentation at both

NAPS Units 1 and 2, for both rock and soil supported structures, to provide a reliable system and to accommodate on-site data interpretation:

The licensee responded that the plan for modernization of the seismic instrumentation at North Anna Units 1 and 2 consists of completed and scheduled work. First, an uninterruptible power source (UPS) was seismically qualified and installed in the control room in September 2011. This UPS provides backup power to the Kinemetrics equipment and Engdahl peak shock alarms in the control room. The seismic switch event alarm and peak shock alarms provide control room operators with immediate feedback regarding whether the operating basis earthquake has been exceeded. Second, an autonomous, temporary free-field seismic monitor was installed inside the North Anna Owner Controlled Area, east of the Training Building, in September 2011. This location was chosen because the soil composition is known, as a result of recent soil borings for the Unit 3 site separation project. In addition, the Station Abnormal Procedure for seismic events was updated to include reference and use of the free-field monitor. Also, a procedure is in place for obtaining and evaluating free-field seismic data as it relates to Cumulative Average Velocity (CAV) and an OBE or DBE exceedance determination. Although the station has not formally adopted RG 1.166 into its licensing basis, both of these actions facilitate the station's ability to assess earthquake data within 4 hours of an earthquake as described in RG 1.166.

The licensee further indicated that a project has been initiated to replace the existing seismic equipment and main control room indication with more modern equipment. Permanent, free-field seismic equipment will be installed to facilitate the performance of CAV calculations. The upgrade will also include installation of seismic recording instrumentation at the station Independent Spent Fuel Storage Installation (ISFSI) pad. The project is currently scheduled to begin equipment installation during the spring 2012 refueling outage.

After its review of above response, the NRC staff asked the licensee during a telephone discussion to describe how plant seismic instrumentation will provide the necessary earthquake information for determining whether an OBE is exceeded. In addition, the NRC staff asked the licensee to provide the free field OBE response settings for the temporary seismic monitoring instrumentation and explain whether this equipment will be used for making plant shutdown recommendations for OBE exceedance.

In its response, the licensee indicated that, in the station's Abnormal Procedure 0-AP-36, *Seismic Event*, the OBE is based on the containment foundation rock spectra and the readings from the Kinemetrics and Engdahl seismic instrumentation. The OBE settings for this instrumentation are:

Vertical	0.04 g
Horizontal	0.06 g

In the station's General Engineering Procedure 0-GEP-30.1, *Free-Field Seismic Instrumentation Data Retrieval and Analysis*, the OBE is based on soil spectra and the readings from the temporary, free-field seismic instrumentation. The OBE settings for this instrumentation are:

Vertical	0.06 g
Horizontal	0.09 g

Following confirmation of a seismic event, the Main Control Room (MCR) operator will follow 0-AP-36 which directs the operator to the control room indication for determination of whether the OBE has been exceeded. As required by procedure, within 4 hours, the Shift Manager or Station Emergency Manager will be provided with the free-field monitor seismic event data. Indication from any of the seismic instrumentation (i.e., Kinemetrics, Engdahl, or temporary free field seismic equipment) that the OBE has been exceeded requires both Units 1 and 2 to be shut down.

As described in the AIT report, the NRC staff found that Engdahl seismometers at the North Anna plant are less reliable than Kinemetrics. The licensee installed the free surface-free field seismometer with temporary settings, while this does not have the direct connection to the MCR instrumental panel to alert plant operator immediately during an earthquake event, the plant operator can still make a decision within the 4-hour limit. Therefore, with the combination of Kinemetrics and free field seismometer, the NRC staff considers the licensee response acceptable. In addition, the licensee has connected the MCR instrumental panel with a non-interruptive seismic qualified backup power, and therefore, power disruption would not be expected in the future earthquake event.

VEPCO indicated that Engdahl seismometers are less reliable than Kinemetrics seismometers (i.e., inconsistent with Kinemetrics in readings and also missing frequency readings). However, the Kinemetrics seismometers at the plant also did not have accurate timing for the recorded time history because the start time of seismic data is estimated. The NRC staff asked the licensee to address how this potential uncertainty impacts the use of the seismic time history when matching it to other recorded events (e.g., the nuclear instrumentation (NI) signal changes) for the reactor shutdown root cause analysis. Considering this issue, the licensee was requested to discuss any plans to update seismic instrumentation at the plant to provide better ground motion recordings for any future earthquake events.

The licensee stated that potential uncertainty regarding accurate start time for recorded seismic time-history associated with the Kinemetrics is merely an inconvenience when making comparisons with other recorded events. Use of an estimated start time is adequate for most other recorded events. For the case of matching the time-history with the NI changes for the reactor shutdown root cause, it was simply a matter of overlaying the time-history and NI signal and matching accelerations with the variations in NI indication. While this is not ideal, it does not present a problem regarding the use of the seismic data. As noted in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee plans to upgrade the seismic instrumentation equipment at North Anna Power Station, which will resolve this issue. In addition, as discussed in the licensee's letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), temporary free-field seismic instrumentation has been installed at the plant that will be used to provide additional, corroborating, seismic response information pending the completion of the permanent modifications.

The NRC staff requested the licensee to confirm the operability and reliability of the seismic instrumentation (specifically, channel orientation, sensor calibration, sensitivity test implementation) and alarming systems to ensure they accurately record earthquake ground motion and provide real-time alarm notifications to the plant operators during any earthquake events.

The licensee responded that the applicable Technical Requirements Manual (TRM) technical surveillance requirements have been completed satisfactorily for the seismic instrumentation and alarming systems following the earthquake. These include channel functional testing and channel checks of installed instrumentation for functionality. This also included channel calibrations of all peak acceleration and response spectrum recorders and the associated control room alarm indications. Channel calibrations were also completed for the time-history accelerographs and the seismic switch control room alarm indications. A channel orientation issue was identified for the time-history accelerographs whereby the horizontal sensors were 90 degrees off specified orientation. This discrepancy was entered into the Corrective Action Program for resolution; however, there is no issue with either affected channel's functionality or their ability to record an earthquake event. Further investigation found no identifiable issues of a vertical recording channel interchanged for a horizontal recording channel for any of the installed systems.

In addition, the licensee also stated that a seismically qualified backup power supply has been installed in the main control room to the seismic monitoring control panel. This will ensure power is available to the alarm indications in the control room for immediate determination of OBE exceedance prompting a controlled unit shutdown. Based on completed inspections and testing following the August 23, 2011, earthquake, there are presently no concerns with the functionality or reliability of the station's installed seismic instrumentation. In addition, the licensee indicated that, in its response dated October 10, 2011 (Serial No. 11-577), the seismic instrumentation at North Anna will be upgraded to enhance the station's ability to monitor and assess seismic events. The NRC staff agrees with the licensee's short term transitional usage of current seismic instrumentation.

The NRC staff requested the licensee to discuss the sensitivity of spectral acceleration value with respect to the methodology used (for example, sampling rates) and any other alternative calculations because the September 17, 2011, report, Enclosure 1, Attachment 3, page 7 of 7, "Kinemetrics Data for Containment Elevation 291 [feet] - Vertical Direction," shows a peak recorded value at about 10 Hz that is greater than 1 g.

The licensee responded that the figure shown in Enclosure 1, Attachment 3, page 7 of 7 of the licensee's letter dated September 17, 2011 (Serial No. 11-520; Reference 1), plots the vertical response spectrum generated from the time-history of the August 23, 2011, earthquake recorded by the Kinemetrics Instrument located at the North Anna Unit 1 Containment Operating Deck (291 feet elevation). The time-history was recorded to an analog tape that was sent to the vendor, Kinemetrics, for processing and baseline correction. The resulting corrected time-history was input into a finite element program (STARDYNE, Version 5.11) to generate the response spectrum plot spanning from 0.2 Hz to 50 Hz in increments of 0.2 Hz. Two outside consultants used the same input time-history and independently generated nearly identical response spectra. Kinemetrics, in their input to the licensee (which was provided to the NRC in the September 17, 2011 letter), also plotted the vertical time-history for comparison to the design basis OBE and DBE curves. According to Kinemetrics, their software requires consistent input frequencies for all response spectra plotted for comparison. Accordingly, their data analysis program plots the response spectrum generated from the recorded time-histories at only those frequencies at which the design spectra curves were digitized and were sent to them. Thus, the frequencies used by Kinemetrics in plotting the vertical response spectrum lack

the refinement and are not consistent with those frequencies that the licensee and other consultants used for plotting the response spectrum.

Kinemetrics results provided in Enclosure 1 of the September 17, 2011, letter were compared to the calculations performed by the licensee. The comparison shows differences in the peak spectral acceleration for the vertical direction spectra at the 291 feet elevation. The apparent difference in this instance is attributed to the frequency points at which Kinemetrics plotted the vertical spectrum generated from the recorded time-history. The licensee's calculated peak spectral acceleration is 1.06 g at 10 Hz; whereas, Kinemetrics reported peak is only 0.973 g. The licensee explained that the value at 10 Hz provided by Kinemetrics was an interpolated value, which caused a difference of less than 1 percent. Therefore, the apparent error was caused because of interpolations used by Kinemetrics and not due to differences in numerical integration methodology or sampling rates. Plotted at consistent frequencies, the Kinemetrics data and the licensee's data are consistent, as is the case with the spectra developed from recorded motions by two other consultants.

The NRC staff agrees with the licensee's explanation that spectral acceleration difference is due to the fact that Kinemetrics methodology requires consistent frequency input for response spectrum calculation. The NRC staff also calculated response spectrum for the three components at the 291-ft elevation level and the results match with the results provided by the licensee.

2.4 Conclusion

The NRC staff concludes that the licensee's characterization of the ground motion from the August 23, 2011, earthquake and its impact on NAPS, Units 1 and 2, were reasonable and acceptable. The NRC staff concludes that the licensee has reasonably demonstrated the operability of the seismic instrumentation during the seismic event at NAPS, Units 1 and 2.

3.0 DESIGN OF STRUCTURES, SYSTEMS, AND COMPONENTS

3.1 Piping and Nondestructive Examination

3.1.1 Introduction

Virginia Electric Power & Company (VEPCO or the licensee) has chosen to use guidance provided in the Regulatory Guide (RG) 1.167, Restart of a Nuclear Power Plant Shutdown by a Seismic Event (Reference 23). The RG provides guidance acceptable to the NRC for licensees to demonstrate following the exceedance of OBE and SSE that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.

VEPCO, in its letter dated September 17, 2011 (Serial No. 11-520; Reference 1), confirmed that the August 23, 2011, earthquake exceeded the spectral and peak ground accelerations for the OBE and DBE for NAPS, Units 1 and 2. For assessing the effects of this earthquake on the structural integrity of piping and pipe supports that are required to be seismically qualified, the licensee stated that it is following the guidance presented in EPRI report NP-6695, Guidelines for Nuclear Plant Response to an Earthquake, (Reference 23), which is endorsed by RG 1.167,

with exceptions. NP-6695 contains guidance for pre-restart and post-restart actions to be performed in accordance with the level of damage observed. Reference 23 provides guidance for assigning damage intensity levels of 0, 1, 2 and 3. The licensee stated in its letter dated September 17, 2011, that it performed focused inspections and observations in accordance with Reference 23, which determined that the EPRI damage intensity level assigned for this earthquake is damage intensity level 0, the indicator of least damage. Conservatively, though, the licensee decided to perform inspections, tests and evaluations of plant SSCs in accordance with an EPRI Damage Intensity 1 versus the observed 0. The damage intensity level of 0 and evaluations in accordance with damage intensity level of 1 was accepted by the NRC staff because this is a more conservative approach.

The NRC staff evaluated the licensee's assessment of the existing pipe stress analyses and inspection of the piping and associated support systems, including scope, inspection/evaluation methods, acceptance criteria, results, and corrective actions. This evaluation addresses, the functionality of the piping systems in both units in accordance with Section V (a)(2) of Appendix A to 10 CFR Part 100 and EPRI NP-6695.

The licensee has submitted reports, including responses to staff's RAI, to show operability and functionality of plant SSCs which demonstrates plant restart readiness. The NRC staff's review of the licensee's submittals in reference to piping and pipe supports is provided below.

3.1.2 Piping Inspection and Nondestructive Examination

Piping Inspection

EPRI NP-6695 provides guidance on the functionality inspection of the piping systems. The NRC staff asked the licensee to discuss piping system inspection scope, the inspection technique and its effectiveness, specific piping components examined (e.g., welds, nozzles, flanges, attachment lugs, and couplings), whether the pipe insulation was removed prior to inspection, the inspection of inaccessible portions of the pipe, acceptance criteria, inspection results, and corrective actions.

According to its initial submittal dated September 17, 2011 (Serial No. 11-520; Reference 1), the licensee, using guidance provided in EPRI NP-6695, has developed Station Procedure 0-GEP-30, "Post Seismic Event System Engineering Walkdown." According to EPRI NP-6695 Section 5.3.2.2, all safety-related SSCs as well as non-safety-related balance-of-plant SSCs required for normal operation of the plant should be walked down and inspected. The licensee using its Station Procedure 0-GEP-30, walked down and inspected all accessible safety and non-safety-related piping and pipe supports in both units. Over 80 systems for Unit 1 and over 50 systems for Unit 2 were walked down for inspections. These piping system numbers (50 and 80) represent 100 percent of the safety-related ASME Class 1, 2, and 3 and 100 percent of the non-safety-related piping systems in both units. Inaccessible sections of piping and pipe supports that the licensee did not walk down included buried piping (see more on buried piping below) and piping in locked-high-radiation areas. VEPCO estimated that less than one percent of Class 1 piping (not including S/G tubes) was not inspected, less than one percent of the Class 2 piping was not inspected and less than one percent (1 percent) of the non-buried Class 3 piping was not inspected. No damage related to the earthquake was identified during piping and support inspections of Class 1, 2, and 3 seismically qualified piping. The minority of piping

and pipe supports in inaccessible areas that were not inspected were determined to be acceptable on the basis that piping and supports that were inspected, both safety and non-safety-related, had no significant physical or functional earthquake damage. In its submittals, the licensee noted that some of the piping inspected included sections of insulated piping that was not removed for these inspections. For the sections of piping that insulation was not removed, the licensee determined acceptability based on the following: the insulated piping was inspected for evidence of earthquake-related damage to the insulation and none was found; the pipe supports on insulated piping are typically not insulated and were inspected with satisfactory results; the insulated piping was inspected for any system leakage through the insulation and no evidence of leakage was found; the extensive amount of un-insulated piping that was inspected had satisfactory results; piping or supports that had its insulation removed for in-service examination or maintenance showed no earthquake-related damage. Based on the above results, the NRC staff finds the licensee's justification that the insulated sections of piping were not damaged acceptable.

The licensee performed inspections of piping and pipe supports. During its 0-GEP-30 procedural inspections, the licensee checked for snubber damage to identify snubbers that pulled loose from foundation bolts, leakage of hydraulic fluid and bent piston rods; for damage at rigid supports to identify deformation of support structure, deformation of pipe due to impact to support structure; for damage of expansion joints; for damage or leakage of piping and branch lines and for damage to pipe at building joints and interfaces between buildings. In addition to the 0-GEP-30 procedural inspections, the licensee visually inspected welds, flanges, attachment lugs and couplings. The licensee, as shown in its submittals, performed inspections of all accessible piping and pipe supports and did not identify any physical or functional damage to the piping systems as a result of the August 23, 2011, earthquake that would render them incapable of performing their specified system functions.

In addition to the above walkdown inspections, the licensee performed sample nondestructive examinations (NDE) of piping welds that were considered to be susceptible to damage from a seismic event as discussed in Attachment 1 to the letter dated September 27, 2011. The licensee reviewed industry earthquake experience to identify piping vulnerabilities. The licensee selected pipe welds in areas that had potential for strong anchor movements (i.e., reactor coolant system (RCS) loop drain piping, containment penetration area piping, and service water (SW) tie-in vault piping). A number of safety-related welds and supports in these areas were then selected for NDE using penetrant testing, magnetic particle testing, or visual examination (VT-3).

The licensee selected the following piping systems for NDE: Unit 1 Pressurizer Spray Line; Unit 1 Safety Injection Line; Unit 2 'A' Loop Drain Line, Unit 2 Seal Injection Line at 2-RC-P-1B Thermal Barrier; Unit 2 Seal Injection Line to 2-RC-P-1C on the Containment side of the Anchor at Penetration No. 35; Unit 2 Seal Injection Line to 2-RC-P-1C on the Auxiliary Building side of the Anchor at Penetration No. 35 - Inspected both sides of the coupling; Unit 2 Safety Injection Line at the RCS Loop 'C' Cold Leg Welds; Unit 2 Pressurizer Vessel integral attachment; and 36-inch common line (i.e., the SW system).

From the above-completed examinations, all inspected welds showed satisfactory results. No flaws, damage or any type of nonconformance on welds was identified by the licensee. The licensee's inspections of supports did not identify any issues attributed to the earthquake. For

two spring-type support issues that were identified (loose riser clamp bolt and spring setting out of tolerance), the licensee created condition reports that were entered in the licensee's corrective action program for repairs

The NRC staff asked the licensee how the inspections were performed for piping and supports that are located in high elevations, e.g., the inspection of the segment of the containment spray piping system and associated supports that is attached to the dome of the primary containment. By letter dated October 28, 2011 (Serial No. 11-566D; Reference 14), the licensee responded that to inspect the quench spray/recirculation spray rings in both units' containments, it accessed the polar crane cat walk (elevation 332 feet) to perform initial inspections. The licensee did not identify any earthquake damage in the initial inspection. However, the licensee noted that visibility was limited due to poor lighting in the initial inspection. Subsequently, the licensee used the platform on the side of the Polar Crane (elevation 344 feet) and re-inspected the areas with the aid of high-power flood lights, binoculars, and a camera with a good zoom feature. This re-inspection confirmed the results of the initial inspections (i.e., no earthquake damage was identified). Paragraph T-953, *Remote Visual Examination*, of Article 9, *Visual Examination,* of the ASME Code, Section V, 2007 Edition, permits the use of visual aids such as binoculars and cameras to perform visual examination remotely. The NRC staff finds the use of binoculars and high-power flood lights are acceptable to determine functionality of the piping system which is located in high elevation.

The licensee inspected pipe movements by damage indicators such as support damage, cracked paint, insulation damage, identified leakage, or damage to local SSCs. The licensee reported that no indication of unanticipated pipe movement was identified and no damage attributable to the earthquake was noted. Because the pipe supports were not damaged significantly, the NRC staff finds that it is acceptable that insulation is not removed from the piping systems when performing walkdown inspection.

The licensee explained that while not specifically identified in the inspection procedure, piping system inspections encompassed pipe welds, nozzles, flanges, attachment lugs, and couplings. In addition, inspection procedure 0-GEP-30 includes the following specific guidance for performing piping inspections: (1) check for snubber damage; i.e., snubbers pulled loose from foundation bolts, leakage of hydraulic fluid and bent piston rods; (2) check for damage at rigid supports; i.e., deformation of support structure, deformation of pipe due to impact to support structure; (3) check for damage of expansion joints; (4) check for damage or leakage of piping and branch lines; and (5) check for damage to pipe at building joints and interfaces between buildings.

The licensee noted that some sections of system piping were inaccessible for inspection, such as buried piping and piping located in locked, high-radiation areas. The licensee dispositioned the inaccessible portions of piping systems based on inspections of associated system components that resulted in no significant damage attributable to the earthquake and/or other piping in the same building or structure with similar supports that was inspected with satisfactory results. Buried piping inspection is evaluated further below.

Based on the above review, the NRC staff finds that the licensee's basis for concluding that piping and pipe supports have not been damaged to be acceptable. Accordingly, the NRC staff finds that it is acceptable that most of the pipe insulation was not removed during the walkdown

to determine the functionality of the piping systems because no damage to piping and pipe supports was identified. In addition, the NRC staff finds that the licensee's walkdown satisfies the guidance in EPRI NP-6695 endorsed by RG 1.167.

Piping Inspection Findings

For the walkdown, the licensee did not identify any physical or functional damage to the piping systems as a result of the August 23, 2011, earthquake that would render them incapable of performing their design functions. A loose bolt was found on a spring hanger riser clamp that is attached to Unit 1 10-inch diameter safety-injection line SI-238-1502-Q1. The licensee determined that the loose bolt was not associated with the earthquake. The licensee repaired the loose bolt on October 5, 2011, as discussed in its letter dated October 28, 2011 (Serial No. 11-566D; Reference 14).

In its letter dated October 31, 2011 (Serial No. 11-566E; Reference 17), the licensee stated that it verified torque on 316 anchor bolts on 51 pipe supports in the Unit 2 Safeguards Building, Auxiliary Building, and Unit 2 Containment. The licensee randomly selected anchor bolts ranged from ½-inch to 1-1/4 inches in size for torque verification. Of the 316 anchor bolts torque tested, all but five passed the test. The five that did not pass were wrench-tight, were re-torqued, which confirmed proper grip, and maintained full-load carrying capability. The five anchor bolts that did not meet the torque checks were in five different supports. The licensee clarified that the remaining bolts in each support passed the torque check, and the affected support remained tight against the wall, indicating that the five wrench-tight bolts were not caused by the August 23, 2011, earthquake.

The licensee reported that in no case were any supports rendered inoperable. The licensee concluded that based on the low number of cycles of strong motion from the August 23, 2011, earthquake, extensive system inspections, and the tightness sampling performed, there is no concern for vibratory damage to expansion anchors. The NRC staff notes that torque verification is part of procedures to support the functionality of the piping system. Based on the licensee's inspection results of the bolts, the NRC staff finds that the licensee has verified appropriately the torque of a reasonable number of the bolts on supports. Therefore, the NRC staff concludes that the licensee has demonstrated no functional damage to the pipe supports.

3.1.3 Buried Piping

Scope of Buried Piping Inspection

The NRC staff is concerned on the functionality of the buried piping because it interacts differently in an earthquake event than the above-ground supported piping systems. By letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee discussed the scope of the buried piping that has been inspected or tested following the earthquake. NAPS has approximately 6.9 miles of buried pipe. Of that length, only approximately 1120 feet of buried piping carries, or has the potential to carry, contaminated fluid. Approximately 100 of the 1120 feet of this buried piping was directly inspected (i.e., excavated for inspection), which included the piping associated with the Unit 1 refueling water storage tank (RWST).

The licensee pressure tested approximately 650 feet of safety injection (SI), recirculation spray (RS), and quench spray (QS) system piping and approximately 6,650 feet (~1.25 miles) of non-contaminated, safety-related SW piping. There is no buried Unit 2 SI piping. The total length of the tested buried pipe is summarized as follows:

Tested Lengths of Buried Safety-Related Pipe (Approximate feet)			
System	**Unit 1**	**Unit 2**	**Common**
Service Water System(SW)	1000	450	5200
Quench Spray System(QS)	110	140	
Recirculation Spray System (RS)	160	200	
Safety Injection System(SI)	35	0	

Pressure Testing of Buried Piping

The NRC staff asked the licensee to discuss the details of the system pressure tests (SPTs) for safety-related buried piping (e.g., pressure used, hold time on the pressure, how leakage would be observed, and the length of pipe that is being pressure tested), acceptance criteria and results. The NRC staff also asked the licensee to discuss the likelihood of crack initiation due to the earthquake and justify how an SPT will ensure the structural integrity of the buried pipes without NDE.

By letters dated October 10 and 18, 2011 (Serial Nos. 11-577 and 11-577A; References 7 and 10, respectively), the licensee responded that to perform a pressure test on the QS system and SI system piping, it used the periodic test procedure, 1/2-PT-302QS, *"RWST and Refueling Water Cooling System Pressure Test" (QS and SI)*. The pressure drop test is performed using the hydrostatic head developed by the RWST. The buried pipe is subjected to approximately 60 feet of hydrostatic head. The licensee's test procedure requires that no decrease in RWST level is allowed over a minimum 8-hour hold time. Any decrease in tank level would be indicative of a piping leak. The testing addressed the buried QS and SI piping for both units.

To perform pressure tests on the RS piping system, the licensee used the periodic test procedure, 1/2-PT-305RS, *"Casing Cooling Pump 1-RS-P-3A System Pressure Test" (RS).* The pressure drop test is performed using the hydrostatic head developed by the casing cooling storage tank. The buried pipe is subjected to an approximately 40 feet of hydrostatic head. No decrease in the casing cooling storage tank level is allowed over a minimum 8-hour hold time.

To perform pressure tests on the auxiliary SW piping system, the licensee used the periodic test procedure, 1/2-PT-301SW, *"Service Water Pump 1-SW-P-4 System Pressure Test."* The unimpaired flow test is performed using the pressure developed by the auxiliary SW pump during performance of its functional test. The buried pipe's pressure is approximately 75 pounds per square inch gauge (psig) at approximately 6,500 gallons per minute (gpm). There is no hourly hold time associated with an unimpaired flow test.

To perform pressure tests on the majority SW piping system, the licensee used the periodic test procedure, 1/2-PT-302SW, *"'A' and 'B' Service Water Supply and Return Headers System Pressure Test,"* including the section of buried pipe. Based on the licensee's test procedure, the

pressure drop test is performed using the pressure developed by the SW pump(s) during normal operation. Per the licensee's test procedure, there is a 48-hour hold time associated with these pressure drop tests, and SW reservoir leakage must be maintained within specified limits.

The licensee noted that the portions of the buried piping associated with the pressure drop tests were performed with satisfactory results. The licensee stated that system pressure tests (SPTs) are required each inspection period (approximately every 3 years) in accordance with the ASME Code, Section XI, requirements. However, the periodic tests discussed above were performed specifically to test buried safety-related piping following the August 23, 2011, earthquake to demonstrate the no functional damages to the piping, not necessarily to satisfy the SPT program requirements. The periodic test method was used in accordance with the ASME Code, Section XI, IWA-5244.

The licensee explained that since these periodic tests provide an indication of gross leakage and do not completely address potential hidden damage, industry insights from EPRI research related to the effect of the Niigata Chuetsu-Oki (NCO) earthquake of 2007 on the Kashiwazaki-Kariwa Nuclear Power Station (K-K) in Japan were reviewed. The licensee identified three areas of concern as potential non-visible damage sources for buried piping: (1) coatings damage, (2) cathodic protection integrity, and (3) fragility of Victaulic couplings.

The licensee noted that any damage to coatings would be from significant ground motion relative to the buried piping. Based on the limited damage to any structures from the earthquake, the licensee does not expect damage to buried pipe coatings. The licensee stated that it will continue to monitor buried piping in accordance with the Nuclear Energy Institute (NEI) buried piping initiative that was previously incorporated into station procedure ER-AA-BPM-101, *"Underground Piping and Tank Integrity Program."* The licensee checks the cathodic protection system on buried piping multiple times per year as part of the preventive maintenance program. Any degradation of the cathodic protection system would be identified well in advance of the development of any long-term piping integrity issues and would be addressed accordingly. According to the licensee, NAPS does not currently have Victaulic couplings associated with buried piping, although the fire protection (FP) piping contains bell and spigot connections that are also susceptible to significant ground motion that could cause leakage.

The licensee has taken additional actions regarding buried piping. For example, the licensee inspected the areas where piping systems penetrate the soil or penetrate building walls into the soil during system walkdowns to verify that no signs of stress on the penetrations or movement of the buried pipes within the soil. The licensee reported that (1) no ground settlement issues or cracks in the soil or roadways were noted around the station, (2) no indications of high stress at the penetrations were noted nor were any cracks present, and (3) no signs of stress on the penetrations or movement of the buried pipes were within the soil. The NRC staff finds that the licensee has inspected a sufficient sample of the buried piping penetrating buildings and found no significant damage to the sample buried piping. As a result, the NRC staff concludes that NAPS has adequately demonstrated no functional damage to buried piping.

Excavated Fire Protection Piping Inspections

The licensee stated that the fire protection (FP) piping system has historically been an area of concern for underground piping leaks due to the bell and spigot joined cast iron construction of the piping. Consequently, the licensee considered the cast iron construction in FP piping to be the most susceptible piping to seismic conditions. The licensee completed a formal, post-earthquake inspection of the excavated FP system piping connecting to the Warehouse 5 FP Pump House. The licensee noted that this FP line was previously inspected as part of the Buried Pipe Program on August 19, 2011 (4 days before the earthquake), and those inspection results were used for comparison. The licensee did not find any anomalies associated with the August 23, 2011, earthquake when comparing the results from the inspection performed on August 19, 2011. The inspection results confirmed that no seismically related damage/leakage resulted from the event.

The licensee photographed another excavated area of FP main-loop piping near the West Security Gate before the area was backfilled to protect the main FP system loop and to allow access through the area for outage activities. The licensee reviewed the photographs and did not identify any issues. The licensee inspected a third excavated FP piping connecting to the North Anna Nuclear Information Center and did not identify any post-earthquake-related issues. The NRC staff finds that the licensee has demonstrated the functionality of the FP piping because the licensee has shown that certain excavated FP pipe segments have no functional damage.

Excavated Unit 1 RWST Piping

The licensee excavated and inspected safety-related buried piping associated with the Unit 1 RWST piping located between the Auxiliary Feedwater tunnel and Quench Spray Pump House. The licensee inspected the following pipe sections: (1) QS piping to the QS pumps suction, (2) QS pump recirculation piping, (3) SI system piping to the High Head and Low Head SI pumps suction, (4) RWST recirculation pumps suction and discharge piping, and (5) refueling purification and blender make-up piping to the RWST. The licensed performed ultrasonic testing (UT) of the pipe-wall thickness on some of the excavated piping. The licensee also examined the areas where the pipes were anchored through building wall penetrations. The licensee did not find any indications of high stress at the penetrations nor were any cracks present. The Unit 1 RWST piping was inspected since it is considered to be high risk consequence piping by the Underground Piping and Tank Integrity Program. The licensee did not find degradation in Unit 1 RWST piping.

The licensee also inspected the Unit 2 circulating water discharge tunnel and an associated liquid waste line. The licensee reported that the discharge tunnel and liquid waste piping had no relevant issues associated with the earthquake.

The licensee inspected the buried piping segments in accordance with the guidance contained in its procedure ER-AA-BPM-101. The inspected piping was in satisfactory condition, and no relevant issues were found. The licensee has reviewed the buried piping inspection schedule created for the NEI buried pipe initiative and determined that the frequency of the inspections is adequate, and no changes to the program are required as a result of the seismic event.

Underground Fuel Oil Tank and Piping

By letter dated October 18, 2011 (Serial No. 11-577A, Reference 10), the licensee stated that it inspected the underground fuel oil tank (encased in sand) and fuel delivery piping for the emergency diesel generator fuel oil storage tank (EDGFOST) system. Specifically, the licensee has verified that each diesel fuel oil tanks have the required amount of fuel for full load operation for 7 days and the system was tested and verified to deliver fuel oil to each diesel generator. The licensee also visually inspected the fuel oil piping. The licensee did not identify any earthquake-related physical damage to the emergency diesel generator support systems, nor did the NRC's AIT identify any damage that would be considered contrary to that determination. The NRC staff concludes that the licensee's actions demonstrate that no functional damage has occurred to the tank/system, as appropriate. The NRC staff's detailed evaluation of the buried tank and fuel delivery piping are discussed in Section 9.2.1 of this technical report.

The NRC staff finds that the licensee has adequately verified the functionality of the safety-related buried piping by either periodic tests (normal pressure tests) or by direct visual and ultrasonic examinations. For the buried piping that was not inspected or tested, the licensee indicated that this piping is not expected to experience cracking due to the earthquake based on the favorable findings for the buried piping that was inspected. The NRC staff notes that the buried piping that was not inspected or tested was non-safety-related, non-ASME Code Class piping. These pipes are not required to be inspected for functionality per RG 1.167. The NRC staff finds that the licensee has acceptably demonstrated the safety-related buried piping remains capable of performing its function.

3.1.4 Pressure Testing of Piping

For ASME Class 1 piping, the ASME Code, Section XI, Table IWB-2500 Examination Category B-P, Item No. B15.10 requires that SPTs be performed prior to plant startup following a reactor refueling outage. For Class 2 and 3 piping, Table IWC-2500-1 and Table IWD-2500-1 require system pressure testing once per inspection period. The NRC staff asked the licensee to discuss whether a system leakage test will be performed on all ASME Class 1, 2, and 3 piping to demonstrate the functionality of the piping systems prior to restart per the above requirements of ASME Code, Section XI. The NRC staff further asked the licensee to discuss whether visual examination will be performed for each piping system as part of the SPT.

By letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee responded that the station will be performing its Periodic Tests 1/2 PT-46.21, *"RCS Pressure Boundary Components Affected by Boric Acid Accumulation,"* to address ASME Class 1, 2, and 3 components that are pressurized inside containment. This procedure is being performed to satisfy the system pressure testing requirements of the ASME Code, Section XI, and will be performed by qualified VT-2 examiners. This periodic test also addresses Main Steam and Feedwater systems outside of containment.

Following the August 23, 2011, earthquake, the licensee performed walkdown inspections for numerous in-service plant systems in accordance with Station Abnormal Procedure 0-AP-36, *"Seismic Event,"* and procedure 0-GEP-30. In addition, in support of the Operability Determinations that were prepared to ensure that plant systems required for entry into Modes 5 and 6 were capable of performing their required functions, the licensee performed an

operability/functionality evaluation, which included the Unit 1 and Unit 2 Service Water System, Component Cooling Water System, Residual Heat Removal System, Reactor Coolant System, Safety Injection System, Fuel Pit Cooling System, and Emergency Diesel Generator (EDG) Fuel Oil System, among others. The licensee did not identify leakage that was attributable to the earthquake.

As part of the preparation for unit restart, prior to entering Mode 4, the licensee will perform system walkdowns in accordance with station procedure ER-AA-SYS-1002, *"System Engineering Walkdowns,"* to ensure piping systems are ready for mode changes. The purpose of the walkdown inspections is to identify any equipment problems (e.g., leakage) or discrepancies prior to unit operation.

In the letter dated October 18, 2011 (Serial No. 577A; Reference 10), the licensee stated that its periodic test (PT) 1/2-PT-46.21, "RCS Pressure Boundary Components Affected by Boric Acid Accumulation," is normally performed during Modes 1, 2, or 3 during each cooldown to Mode 5 prior to a refueling outage to identify any active or inactive RCS pressure boundary leakage, and during each startup from Mode 5 following a refueling outage to perform the RCS SPT in accordance with the ASME Code, Section XI. Insulation is not removed for this inspection; however, the inspection is performed by VT-2 qualified inspectors.

As noted in the letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee stated that the periodic test per procedure 1/2-PT-46.21 will also be used during unit startup for both Units 1 and 2 to perform an RCS SPT in accordance with the ASME Code, Section XI. This test requires a 4-hour hold time for insulated components and a 10-minute hold time for non-insulated components. Comprehensive system leakage inspections are then performed by VT-2 qualified personnel. The licensee stated that SPT per procedure 1/2-PT-46.21 will serve as one of the final confirmations of RCS system integrity prior to the units returning to Mode 2. This procedure also includes VT-2 inspections of main steam and feedwater piping inside and outside containment.

During refueling outages, the licensee uses procedure PT 1/2-PT-48, "Visual Inspection of Reactor Coolant Pressure Boundary Components," to visually examine bolted connections of ASME Class 1 pressure boundary components to identify leakage sources and fastener degradation due to boric acid for both units. This procedure also inspects a small number of Class 2 and 3 components due to their relationship and safety significance to the RCS (e.g., residual heat removal (RHR) pumps, component cooling line connection to the reactor coolant pump thermal barrier.) The licensee removes insulation from bolted connections to facilitate the inspections. For the Unit 2 refueling outage in 2011, commenced following the August 23, 2011, earthquake, the licensee performed visual inspection per procedure PT 1/2-PT-48 and did not identify damage attributable to the earthquake.

The NRC staff finds that the licensee will perform SPTs in accordance with the ASME Code, Section XI during Mode 3. The SPTs are tests additional to the walkdowns performed after the earthquake to verify the functionality of the piping systems. The SPTs will provide additional assurance of the piping functionality.

In summary, the NRC staff finds that the licensee has demonstrated that there is no functional damage to the piping systems in accordance with Section V(a)(2) of Appendix A to 10 CFR Part 100.

3.1.5 Verification of Existing Flaws

The licensee observed a leak on control rod drive mechanism (CRDM) N2-18 canopy seal weld on the Unit 2 reactor vessel head as part of its inspection activities during the refueling outage in September 2011 which was commenced after the August 23, 2011, earthquake. The NRC staff asked the licensee to discuss whether the leakage occurred before or after the earthquake and the associated repair method. Also, the NRC staff asked the licensee to identify any piping systems that contain flaws in service prior to the earthquake and discuss the associated inspections. By letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee responded that the subject CRDM pressure housing is a spare, capped pressure housing. Spare CRDM pressure housings are fitted with an adapter plug that accommodates mounting of a “dummy can” assembly that mimics the resistance to cooling air flow that would otherwise be provided by an active CRDM.

The licensee explained that the design of this adapter plug relies on a robust threaded connection to provide the structural support, and the primary pressure boundary for the joint, while the associated canopy seal weld provides a seal for leakage past the threads. The licensee noted that the loading associated with this joint and experienced by the canopy seal weld would be primarily due to pressure/thermal cycles and not associated with inertial loading from a transient or seismic event. According to the licensee, while it cannot be definitively determined whether the canopy seal weld leak occurred before or after the earthquake, it is not anticipated that the loading associated with the seismic event would have either initiated a flaw or resulted in any crack growth associated with any existing flaws. The NRC staff notes that it would be difficult to determine whether the canopy seal weld cracking is caused by the recent earthquake unless the degraded canopy seal weld is removed for destructive examination. The intent of the EPRI NP-6695 is to determine no functional damage to the canopy seal weld. The NRC staff finds that crack initiation and growth would not be a concern to the functionality of the canopy seal weld.

The licensee repaired the canopy seal weld by installing a Westinghouse Canopy Seal Clamp Assembly. This design uses a Garfoil Seal ring to provide leak-tight integrity. Additionally, the compressive loading applied across the canopy seal, combined with the compressive loads applied to the face of the canopy seal weld from the Garfoil packing material, tends to result in crack tip closure, thereby arresting any further crack propagation. The NRC staff finds that the licensee has repaired the degraded canopy seal weld. Therefore, the licensee has demonstrated that there is no functional damage to the CRDM N2-18 per RG 1.167.

Regarding flaws that existed in systems prior to the August 23, 2011, earthquake, the licensee reported three existing flaws in piping in the letter dated October 10, 2011 (Serial No. 11-577, Reference 7): Unit 2 outside recirculation spray suction piping, weld 4 of Unit 2 pressurizer girth weld, and weld 6 of Unit 2 ‘B’ steam generator girth weld.

In the letter dated October 18, 2011 (Serial No. 577A; Reference 10), the licensee stated that the Unit 2 outside recirculation spray piping flaw was a surface indication as opposed to an

imbedded flaw. The licensee inspected this flaw using liquid penetrant testing and compared the results with the results of the previous inspection. The licensee reported that the flaw remained a non-recordable indication.

Weld 4 is a Code Category B-B/Item B2.11 circumferential shell to bottom head weld on the Unit-2 Pressurizer. The licensee performed ultrasonic examination in 2007 of this weld and recorded it as an acceptable subsurface indication when compared to the acceptance standards of the ASME Code, Section XI, IWB-3510-1. The licensee characterized this indication using amplitude-based sizing techniques, which recorded dimensions of 0.09-inch through-wall and 0.4-inch length. The licensee ultrasonically re-examined this indication as part of the post-seismic event examinations during the Unit 2 2011 outage commended following the August 23, 2011, earthquake and found it to be essentially unchanged. This indication was characterized using the same amplitude based sizing technique that was used during the 2007 examination. In addition, the licensee used the ASME Code, Section XI, Appendix VIII demonstrated tip-diffraction techniques, which is more accurate than the technique used in 2007, to determine the through-wall extent of this indication. When compared to the ASME Code, Section XI, IWB-3510-1 acceptance standards, this flaw is characterized as an acceptable subsurface indication. Based on the licensee's inspection results, the NRC staff finds that there is no functional damage to Weld 4 per RG 1.167.

Weld 6 is a Code Category C-A/Item C1.10 circumferential vessel weld in the Unit 2 "B" steam generator. The licensee indicated that examination of this weld in 1995 revealed an inclusion that was determined to be acceptable. The licensee performed the initial ultrasonic examination in 1995 from the outside surface using amplitude based sizing techniques, which recorded dimensions of 0.55-inch through-wall and 1.06 inches in length. Access was available to the inside surface at the time of this [1995] examination, and the licensee performed additional NDE from the inside surface to assist with the characterization of the indication. The licensee performed supplemental magnetic particle and ultrasonic examinations from the inside surface to better determine the proximity of the flaw to the inside surface. The results of these supplemental examinations showed that the flaw was not connected to the inside surface. The indication is embedded 0.435-inch away from the inside surface. The supplemental ultrasonic examination using amplitude-based sizing techniques determined that this indication had a through-wall extent of 0.065-inch and a length of 1.06 inches. The licensee evaluated this indication as an acceptable subsurface indication in accordance with the acceptance standards of the ASME Code, Section XI, IWC-3510-1.

The licensee re-examined Weld 6 during the 2007 refueling outage. The 2007 examination results were essentially unchanged and considered to be within the tolerance of the examination techniques from the 1995 outside surface examination. The licensee re-examined this indication as part of the post seismic event examination scope during the Unit 2 outage in 2011, which commenced after the August 23, 2011, earthquake. The initial examination utilized amplitude-based sizing techniques similar to the examinations performed for the 1995 and 2007 examinations. The amplitude-based indication dimensions for the 2011 examination are similar to the dimensions from the 1995 and 2007 examinations, and the indication is considered unchanged from the initial detection examination performed in 1995. In addition, the licensee used more accurate indication characterization techniques in accordance with the ASME Code, Section XI, Appendix VIII, and obtained a dimensions of 0.163-inch through-wall and 1.05 inches in length. When compared to the ASME Code, Section XI, IWC-3510-1 acceptance

standards, this flaw is still acceptable. The NRC staff notes that the difference in flaw sizes between the amplitude-based sizing technique and the ASME Code, Section XI, Appendix VIII technique (i.e., Performance Demonstration Initiative) can be attributed to the improvements in ultrasonic testing, not the flaw growth itself.

The licensee concluded that no pre-existing flaw experienced growth as a result of the August 23, 2011, earthquake. The licensee stated that these inspection results are directly applicable to Unit 1 as the overall loading environment would have been the same for both units during the earthquake.

The NRC staff finds that the licensee has demonstrated that those components that contain existing flaws have been verified and inspected in accordance with the ASME Code, Section XI to be acceptable to perform their functions. Therefore, the NRC staff concludes that NAPS has demonstrated no functional damage in those components that contain existing flaws.

3.1.6 Pipe Stress Analyses Verification

The NRC staff notes that the potential impacts of the earthquake on piping in terms of stresses are twofold. The first impact is that pipe may be moved or shifted permanently from its original designed and analyzed position as a result of the earthquake. The NRC staff further notes that the dislocated pipe may generate permanent stresses in the piping system that were not analyzed in the original stress analysis and need to be analyzed to ensure that the final stresses are still bounded by the allowable stresses of the ASME Code, Section III. The second impact is that the earthquake will generate temporary pipe loading due to shaking of the pipe. Although this is a temporary, transient loading, it should be considered as part of the pipe load combinations because it was not analyzed in the original pipe stress analysis.

The safety-related and seismically-qualified piping systems are designed for the loads based on the OBE and SSE. The NRC staff asked the licensee to describe in detail how the pipe stresses of ASME Class 1, 2, and 3 piping systems and any non-safety-related piping systems which connect to or could affect ASME Class 1, 2, or 3 piping systems are re-evaluated considering the loading from the recent earthquake.

The licensee performed preliminary analyses to assess the impact of this earthquake on several piping systems in Unit 1 containment. The licensee stated that the Unit 1 analyses are applicable to Unit 2 piping systems and containment due to the similarity of design. As documented in Reference 10, the licensee evaluated six cases of Unit 1 containment piping systems for the purpose of determining the effects of the August 23, 2011, earthquake. They include piping from various safety-related systems and encompass a wide range of large and small bore nominal pipe sizes (NPS), classes (ASME Class 1, 2, and 3), operating temperatures (hot and cold), and elevations (high and low) in the NAPS Unit 1 containment. The licensee analyzed two portions of component cooling piping based on different pipe sizes and operating conditions. The licensee selected containment systems because the recorded time-histories from the Kinemetrics instruments for the August 23, 2011, earthquake at the containment basemat are believed to be more representative compared to the recorded data at other locations. Each case compares the results of the previous design-basis response spectra (from the analysis of record) with the results from the recorded response spectra that occurred on August 23, 2011.

By letter dated October 18, 2011 (serial No. 11-577A, Reference 10), the licensee considered the following criteria in the selection of piping systems for this study:

(1) Various safety-related systems in containment are considered – main steam (32" NPS), feedwater (16" NPS), component cooling (3", 6" and 8" NPS), steam generator blowdown (2" and 3" NPS) and reactor coolant loop (27.5", 29" and 31" NPS).

(2) High-temperature and low-temperature systems – high-temperature systems are generally supported with fewer rigid supports making them more flexible and thus more susceptible to seismic loading.

(3) High-elevation and low-elevation systems – It is important to consider as many elevations as possible, since the NAPS containment showed spectral exceedances in the lower elevations, and to also consider the amplification in the containment structure in the higher elevations as shown in the design-basis response spectra.

(4) Highly stressed piping – the analyses of record were reviewed to ensure the sampling includes cases where the piping is highly stressed due to seismic loading, and therefore, has limited margin to Upset and/or Faulted Code allowables.

(5) Analyses that show low first mode frequencies were selected to ensure that the piping system would show the effects of seismic loading in the frequencies most likely to cause damage (approximately 2 Hz to 10 Hz).

(6) ASME Piping Classes 1, 2, and 3 were considered.

(7) Large- and small-bore piping systems were considered.

The licensee compared stresses due to design basis seismic spectra (DBE) and the recorded spectra of the August 23, 2011, earthquake. Based on its the comparison, the licensee concluded that the stress in the pipe and pipe supports remained within ASME Code, Section III, Level C equivalent allowable stresses during the August 23, 2011, earthquake. The NRC staff notes that in accordance with the NRC Inspection Manual Part 9900, "Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," Section C.10, "Piping and Pipe Support Requirements," piping and pipe supports are capable to be termed operable (and functional) if their stresses for a given event remain below their ASME Code, Section III, Appendix F allowable values. ASME Section III, Level C allowable values are less that the Appendix F allowable values. The NRC staff finds that with the representative sample analyses performed, which showed that piping and pipe supports have remained below their Appendix F limits, the licensee has provided additional assurance (to walkdowns, inspections and exams) on the piping systems functionality and operability.

As shown above, the licensee has performed and completed inspections, sampled piping and performed piping analyses; and performed functional tests including pressure and leak testing

which have shown that seismically qualified piping and pipe supports after experiencing the August 23, 2011, earthquake have maintained their capability of performing their specified system functions.

3.1.7 Pipe Support Verification

Pipe supports include rigid and spring hangers, lateral rigid struts, pipe clamps, snubbers, steel beam box support structures, and anchors. Pipe supports also include attachment lugs that are welded to the pipe outside wall to keep the pipe clamps in place. If a pipe support is degraded as the result of the earthquake, the functionality of the pipe may be affected and eventually lead to degradation. The NRC staff asked the licensee to discuss which pipe system supports were inspected, inspection technique and its effectiveness, what parts of the supports were inspected, acceptance criteria, and corrective actions. The NRC staff also asked the licensee to discuss the re-evaluation of the pipe support structural analyses considering the earthquake effect, including acceptance criteria, results, and corrective actions.

By letter dated October 10, 2011 (Serial No. 11-577; Reference 7), the licensee responded that piping system inspections, including supports, were performed in accordance with station procedure 0-GEP-30, which was developed using the guidance provided in EPRI NP-6695. The licensee stated that for both units it inspected every plant piping system and associated supports to the extent possible and no significant pipe support damage was identified due to the earthquake that would have prevented the pipe from performing its function.

Procedure 0-GEP-30 includes the following inspection criteria for pipe supports: (1) check for damage to anchorage, i.e., stretching or loosening of anchor bolts or nuts, rocking or sliding of base plates on concrete; (2) made up properly, aligned correctly and have sufficient hydraulic fluid levels with no signs of hydraulic fluid leakage; (3) properly installed and no signs of damage; (4) no signs of excessive vibration or movement; and (5) check for deformation of dead weight supports and sway bracing. As discussed in the previous section of this safety evaluation, the licensee has verified and confirmed the functionality of the pipe supports with minor deficiencies such as one loose bolt at a pipe hanger and insufficient torque at five bolts of pipe supports, which were not related to the August 23, 2011, earthquake.

In the letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), the licensee stated that the pipe supports on insulated piping systems are typically not insulated and were available for visual inspection. The licensee inspected readily accessible pipe supports, attachment lugs, and clamps as part of the overall piping inspections. The only portions of the piping systems that were not inspected were those areas of piping located in locked, high-radiation areas and buried piping. The licensee reported that no earthquake-related damage was identified on any of the inspected supports.

As shown in Section 1.1.2.6, the licensee sampled piping for analyses which resulted in pipe and pipe support stresses lower than ASME Code, Section III, Level C and ASME Code, Section III, Appendix F stresses. This provides additional assurance that safety-related pipe supports remain functional and operable for restart after the August 23, 2011, earthquake.

The licensee's inspection of the snubbers is evaluated in Section 3.3 of this evaluation.

Based on its review of the licensee's inspections and evaluations, the NRC staff concludes that for the restart of the NAPS, the licensee has adequately verified in accordance with the RG 1.167 endorsed EPRI NP-6695 report that seismically qualified piping and pipe supports maintained their functionality following the August 23, 2011, earthquake. Based on the licensee's inspection, the NRC staff finds that there is no functional damage to the pipe supports.

3.1.8 Leak-Before-Break Analysis

The NAPS UFSAR Section 3.6.2.4, "Locations of Postulated Pipe Breaks," states that the main coolant loop piping was approved for leak-before-break (LBB) by the NRC. The NRC staff asked the licensee to discuss the effects of the loadings from the August 23, 2011, earthquake on the existing LBB analysis. By letter dated October 3, 2011 (Serial No 11-566; Reference 4), the licensee responded that the LBB analysis for the RCS main loop piping is documented in Westinghouse Electric Company's WCAP-11163, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for North Anna, Units 1 and 2," August 1986, and its associated Supplement 1, "Additional Information in Support of the Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for North Anna Units 1 and 2," dated January 1988. The licensee further stated that WCAP-11163 showed that the maximum moment in the NAPS primary loop piping is less than 60 percent of the generic maximum moment used by Westinghouse in an earlier generic LBB study. For each unit, five weld locations in the primary loop were selected for crack evaluation because they were either maximum load critical locations and/or critical fracture toughness locations. The calculated critical crack size has a margin of at least 2 to the leakage crack size.

In the letter dated October 18, 2011 (Serial No. 11-566B; Reference 11), the licensee stated that a quantitative comparison of two parameters, Cumulative Absolute Velocity and Base Shear Loading on the containment basemat, established that the influence of the August 23, 2011, earthquake was less severe than the Design Basis Earthquake (DBE). As stated in its letter dated October 3, 2011 (Serial No. 11-566; Reference 4), the licensee concluded that the LBB analysis was still valid based upon the existing margin in the analysis without quantifying the load due to the recent earthquake and revising the fracture mechanics evaluation.

In order to quantitatively support its previous conclusions, based upon margin, the licensee analyzed a representative reactor coolant loop for the recorded response spectra in the containment building, corrected to the appropriate building elevation, based on the recent earthquake. The seismic load from this sample analysis was compared with the design-basis seismic loading in the original LBB analysis. The load on the loop piping due to the recent earthquake is found to be less than the seismic loading due to DBE. As the other loads (e.g., thermal and deadweight) remained the same, the existing LBB analysis remains valid.

The NRC staff finds that for the startup of NAPS, the licensee has verified that the existing LBB analysis with the loading from the August 23, 2011, earthquake satisfies NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP) Section 3.6.3, "Leak-Before-Break Evaluation Procedures." The NRC staff finds that the licensee has acceptably verified the LBB analysis for the startup of the NAPS.

3.1.9 Conclusion

For the reasons set forth above, the NRC staff finds that the licensee has performed appropriate verification for the LBB analysis and adequately evaluated piping systems and pipe supports. The NRC staff further concludes that the licensee demonstrated that no functional damage has occurred to piping and pipe supports, which are necessary for continued operation without undue risk to the health and safety of the public.

3.2 Mechanical and Civil Engineering

3.2.1 Description of Licensee Evaluation/Actions

In its letter dated September 17, 2011 (Serial No. 11-520; Reference 1), the licensee stated that initial visual inspections were performed by engineering personnel immediately following the August 23, 2011, earthquake, and the subsequent aftershocks up to August 26, 2011. The damage discovered during these inspections did not identify any significant physical or functional damage, as defined in EPRI NP-6695, to safety-related SSCs and only limited damage to non-safety-related SSCs. The results of these focused inspections supported an EPRI damage intensity of 0, which is defined in Table 2-1 in EPRI NP-6695. To confirm the EPRI damage intensity, the licensee performed expanded inspections of plant SSCs in accordance with an EPRI Damage Intensity 1 to further assess the impact of the earthquake on plant SSCs.

The licensee also stated that: (1) comprehensive inspections of NAPS, Units 1 and 2, SSCs were completed in accordance with station procedures which were either created or revised to incorporate EPRI NP-6695 guidance regarding post-shutdown inspections following a seismic event; (2) the results of these inspections did not identify any significant physical or functional damage to safety-related SSCs that would render them incapable of performing their design functions; (3) reported damage and observations from the earthquake included limited cracking of ceramic/porcelain components on switchyard equipment, and limited cracking of non-safety-related walls; (4) the most significant visual damage of a non-safety-related SSCs was spalled concrete on a condensate polishing tank support pedestal that did not affect function; and (5) the most significant damage that required repair of non-safety-related equipment was generator step-up transformer bushing leakage.

Other than the above items, the licensee did not report any physical or functional seismically induced damage to non-safety-related or safety-related SSCs. The licensee also stated that a limited scope inspection of the plant was conducted by a seismic review team that included engineers from the licensee's organization and industry seismic experts. No significant physical or functional earthquake-induced damage, as defined in EPRI NP-6695, was observed for the areas and SSCs inspected. The licensee provided further supplemental information in response to the NRC staff's RAIs. This additional information is discussed below.

3.2.2 NRC Staff's Evaluation of Licensee Evaluation/Actions

3.2.2.1 Containment Structure

As described in Section 3.8.2, "Containment Structures," of the NAPS UFSAR, (1) the containment structure is classified as seismic Class I and (2) the containment structure is a steel-lined, heavily reinforced concrete structure with vertical cylindrical wall and hemispherical dome, supported on a flat basemat.

In response to the NRC staff's RAI, the licensee stated in its letters dated October 20, 2011 (Serial No. 11-566C; Reference 12), October 10, 2011 (Serial No. 11-577; Reference 7), and October 3, 2011 (Serial No. 11-566; Reference 4), that the containment structural components (including the containment concrete shell, liner plate, and other internal structures), other seismic Class I structures, including those that could adversely affect seismic Class I SSCs, the turbine building structural components including the turbine pedestal, and all masonry walls were inspected on NAPS, Units 1 and 2.

The licensee stated that no damage was noted during any of the structural inspections that were performed that would have affected the structural integrity of the components inspected. Identified damage was minimal and primarily consisted of cosmetic concrete/grout spalling that only required grout or caulk repairs. The following provides specific details relative to the licensee's response:

a) The post earthquake civil/structural inspections of the Unit 1 and 2 Containment exteriors were completed with the use of a crane and man-basket. The inspection guidance that was used during the post-earthquake inspections was detailed and provided assurance that no changes had occurred from the last ASME Section XI, IWL inservice inspection. No damage that could be attributed to the effects of the August 23, 2011, earthquake was identified.

b) The containment liner plate was visually inspected for cracks, buckled areas or pitted surfaces. The results of this inspection were compared with the ASME Section XI, IWE inservice inspection history to identify any anomaly. No damage that could be attributed to the effects of the August 23, 2011, earthquake was identified.

c) The licensee stated in its letter dated October 3, 2011, that only minor damage of a reinforced concrete wall, as part of the containment internal structures, was identified (i.e., some cracking of grout at the junction of two original construction concrete pours).

d) The steel structures inside containment were also inspected to determine whether there was any damage at bolted and welded connections, anchorages, as well as any movement or distortion of members. There was no visual evidence of any significant physical or functional damage.

e) The reinforced concrete structures inside the containment building function primarily as shield walls and pressurized compartments; hence, they are

designed as relatively thick shear walls and slab sections to provide adequate radiation shielding and to resist accident pressure and temperature load cases. DBE seismic-load cases are similarly included in the respective accident and normal load combinations for containment internal structures; however, the DBE load demand is only a minor portion of the total load demand on these structures.

f) The major steel structures inside containment are a network of beams and columns, which support steel grating walkways in the annulus regions of containment. These structures are relatively lightly loaded during plant operation, since these areas mainly provide walkways for plant personnel and equipment laydown areas. These structures are braced in the lateral directions by the crane wall, so lateral seismic loads do not govern their design. The major vertical loads for these interior containment steel structures are gravity loads from plant personnel and equipment laydown loads, which were not present at the time of the August 23, 2011, earthquake. Hence, seismic loads do not account for a major portion of the load demand on these interior containment steel structures. Similarly, there was significant available design capacity to accommodate increases in load demand at the time of the August 23, 2011, earthquake.

g) In response to the NRC staff's RAI, the licensee stated in its letter dated October 20, 2011, that inspections were performed for major equipment support structures on both NAPS, Units 1 and 2. These inspections looked for potential earthquake damage indicated at base plates, anchor bolts, structural members, and supporting concrete. These inspections included major equipment such as, reactor vessel, reactor coolant pumps, pressurizer, steam generators, safety-injection accumulators, recirculation spray heat exchangers, and RHR heat exchangers. Major equipment outside containment, such as turbine/generator, feedwater heaters, feedwater pumps/motors, secondary drain pumps, bearing cooling pumps, service water pumps, circulating water pumps, low-head safety-injection pumps, safety-injection pumps, component cooling pumps, instrument/service air compressors and tanks, steam generator blowdown heat exchangers and tanks, etc., was also inspected. No findings of earthquake damage were identified.

Additional inspections on Unit 2 major equipment support structure were performed as part of the normal inservice inspections performed during Unit 2 refueling outage. These included VT-1 inspection of specific welds on the Unit 2 steam generator 'A' support frame, liquid penetrant test of integral foot on the RHR heat exchangers, and VT-3 inspection of integral support feet for the RHR heat exchangers. Finally, VT-3 inspections were completed for Unit 1 and Unit 2 reactor vessel supports (cold leg/hot leg). These inspections have identified no functional damage related to the August 23, 2011, earthquake.

h) The potential high-stress areas inside and outside of Unit 1 and 2 containments, including the electrical and mechanical penetration area, the equipment and personnel hatches, the main steam and feedwater line penetrations in main steam valve house, and the safeguards building penetrations, were inspected.

The results of these inspections did not identify any damage that would affect the structural integrity of the components inspected.

i) As depicted in the NAPS UFSAR, a partial height of the containment structure is below grade and may not be readily accessible for visual inspection. The NRC staff requested the licensee to provide further information to demonstrate structural adequacy of the containment structure. In response to the NRC staff's RAI, the licensee, in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), provided information relative to an additional evaluation performed to determine the total base shear in the containment structure. This evaluation demonstrated that the total base shear, at the top of the containment base mat, resulting from the August 23, 2011, earthquake, was enveloped by the NAPS design basis earthquake base shear.

Considering the licensee's response to the NRC staff's RAI, the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not adversely affect the structural integrity of the containment structure and its internal structural steel and reinforced concrete structures and thus, these structures remain capable of performing their intended design functions. This conclusion is based on the following:

a) The licensee's post-earthquake civil/structural inspections of the Unit 1 and 2 containment exterior concrete surface and liner plate surface did not reveal any damages that could be attributed to the August 23, 2011, earthquake. These inspections were detailed and provided assurance that no changes had occurred from the last ASME Code, Section XI, IWL and IWE inservice inspections.

b) The licensee's inspection of the containment internal structures only identified a minor damage (some cracking of grout at the junction of two original construction concrete pours) of a reinforced concrete wall.

c) As part of the seismic system assessment performed by the NRC Augmented Inspection Team (AIT), the AIT walked down the Unit 1 containment building to visually inspect various SSCs at different floors. The NRC AIT only observed a minor crack on the incore room wall inside the Unit 1 containment building which is consistent with the licensee's findings.

d) The NRC restart readiness inspection team concluded that the licensee has performed adequate inspections, walkdowns and testing to ensure that safety-related SSCs have not been adversely affected by the August 23, 2011, earthquake.

e) The containment structure is designed for load combinations described in Table 3.8-9 of the NAPS UFSAR. The load combinations that include the effect of earthquake (OBE or DBE) also include the effects of design-basis accident pressure and temperature. The dominant load for the reinforcing steel design is the design-basis accident pressure which creates significant tensile membrane stresses in the containment structure. The temperature rise associated with the design-basis accident creates a significant compressive strain in the liner plate

system which in turn results in membrane tensile stresses in the containment reinforced-concrete elements. The accident pressure and temperature loading conditions were not present during the August 23, 2011, earthquake. Instead, the absence of the accident pressure and temperature provided an ample margin of reserve capacity during the August 23, 2011, earthquake.

Furthermore, the licensee performed a quantitative evaluation of the containment structure to determine the effects of the August 23, 2011, earthquake. In this evaluation, the total base shear, at the top of the containment base mat, due to the NAPS DBE enveloped the total base shear resulting from the August 23, 2011, earthquake. This provides a quantitative measure, in addition to the results of the inspections, of the effect of the August 23, 2011, earthquake on the containment structure. Also, this quantitative evaluation and the absence of the accident pressure and temperature loadings, as noted above, provides reasonable assurance that the below grade portion of the containment structure was not adversely affected during the August 23, 2011, earthquake.

f) The containment liner plate and access openings have been designed for the effects of accident pressure and temperature in combination with DBE as shown in Table 3.8-7 of the NAPS UFSAR. The absence of the accident pressure and temperature provided an ample margin of reserve capacity during the August 23, 2011, earthquake. In its letter dated October 3, 2011, the licensee provided the results of a quantitative evaluation of the containment liner plate for operating design pressure and operating temperature conditions. This evaluation demonstrated that the maximum principal stresses due to the operating pressure and temperature loads are approximately 1/3 of the allowable stress limit; hence, there was ample margin to accommodate the August 23, 2011, earthquake effects.

g) As stated in Section 3.8.2.2.1, “Containment Structure Interior,” of the NAPS UFSAR, the interior cubicles within the containment structure are designed and constructed to withstand the localized pressure pulse effects of a double-ended rupture of a reactor coolant pipe. All structural components, walls, floors, and beams enclosing these cubicles are designed to withstand this differential pressure. The design of the structural components of the steam generator cubicles and primary shielding is based on a combination of maximum temperature, pressure, and thrust loads associated with the double-ended pipe rupture plus the DBE. The absence of the effects of double-ended pipe rupture provided an ample margin of reserve capacity during the August 23, 2011, earthquake.

h) Major equipment supports, including base plates, anchor bolts, structural members, and supporting concrete inside the containment structure (e.g., reactor vessel, steam generators, pressurizer, reactor coolant pumps, safety-injection accumulators, recirculation spray heat exchangers, and RHR heat exchangers) and major equipment outside the containment building were inspected and no damage was identified that could be attributed to the August 23, 2011, earthquake.

i) The containment liner plate areas of electrical and mechanical penetration areas, equipment and personnel hatches have been inspected, by the licensee, and no structural distress was identified.

j) As the licensee reported in its letter dated September 17, 2011 (Serial No. 11-520; Reference 1), the recorded response spectra at the containment base mat which is founded on rock, in the range of frequencies most damaging to structures, 2 to 10 Hz, did not exceed the NAPS DBE in the East-West direction, but only exceeded, on average, the North-South direction by about 12 percent and the vertical direction by about 21 percent.

3.2.2.2 Seismic Class I Structures (Other than Containment Structure)

Section 3.8.1.4, "Analytical Techniques," of the NAPS UFSAR discusses the design of seismic Class I structures. It is stated that seismic Class I structures are primarily of reinforced-concrete construction. The principal components that transmit horizontal and vertical loads to the foundation are the reinforced-concrete roof and floor slabs, and both interior and exterior reinforced-concrete walls. Since the thickness of these components are usually controlled by requirements for biological shielding or tornado and interior missile protection, stresses, and strains are generally not significant.

As shown in Section 3.8.1.3.2, "Load Equations," of the NAPS UFSAR, all seismic Class I structures are designed for OBE and DBE load combinations. The OBE load combinations are based on allowable stress for structural steel and normal working stress for reinforced concrete. A check was then made for the DBE to ensure that the maximum stress did not exceed 90 percent of the minimum yield strength for structural steel, the capacity reduction factor times either the compressive strength for concrete, or the minimum yield strength for reinforcing steel.

In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that all seismic Class I structures (except for containment, which is addressed elsewhere in this evaluation) and those structures that could adversely affect seismic Class I SSCs, the turbine building structural components including the turbine pedestal, and all masonry walls, were visually inspected and the results of these inspections showed no sign of structural distress which could be attributed to the effects of August 23, 2011, earthquake. The licensee further stated that no significant damage was noted during any of the structural inspections that were performed that would have affected the structural integrity of the components inspected. Identified damage was minimal and primarily consisted of cosmetic concrete/grout spalling that only required grout or caulk repairs.

Considering the licensee's response to the NRC staff's RAI, the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not adversely affect the structural integrity of seismic Class I structures, and thus, these structures remain capable of performing their intended design functions. This conclusion is based on the following:

a) The licensee's structural inspections of all seismic Class I structures identified no significant damage that would have affected the structural integrity of the components inspected. Identified damage was minimal and primarily consisted of cosmetic concrete/grout spalling that only required grout or caulk repairs.

b) The NRC AIT walked down the auxiliary building to visually inspect various SSCs. The walkdown included a majority of the Unit 1 auxiliary building elevations. During the walkdowns, the NRC AIT did not observe significant damage and only observed some minor cracks in the interior wall of the auxiliary building which is consistent with the licensee's findings.

c) The NRC restart readiness inspection team concluded that the licensee has performed adequate inspections, walkdowns and testing to ensure that safety-related SSCs have not been adversely affected by the August 23, 2011, earthquake.

d) In accordance with the NAPS UFSAR, the seismic Class I structures have been designed to remain elastic for DBE load condition.

e) As the licensee reported in its letter dated September 17, 2011, the recorded response spectra at the containment base mat which is founded on rock, in the range of frequencies most damaging to structures, 2 to 10 Hz, did not exceed the NAPS DBE in the East-West direction, but only exceeded, on average, the North-South direction by about 12 percent and the vertical direction by about 21 percent.

3.2.2.3 Service Water Reservoir

As noted in Table 3.2-1 of NAPS UFSAR, the service water reservoir is classified as seismic class I. In accordance with Section 3.8.4.4, "Analysis of Stability," of the NAPS UFSAR, the service water reservoir was evaluated for acceleration values of 0.18 g and 0.12 g in the horizontal and vertical directions, respectively. This section of the UFSAR also states that the relative displacement along the centerline of the dikes due to earthquake ground waves will not exceed 3 inches and the impervious core will sustain this relative displacement without cracking.

The licensee stated, in its letter dated September 17, 2011 (Serial No. 11-520; Reference 1), that (1) the NAPS service water reservoir was inspected and evaluated following the August 23, 2011, earthquake and (2) based on the available instrument data and the inspection observations, the service water reservoir sustained no significant physical or functional damage and remains capable of performing its intended design functions.

The licensee's RAI response letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), provided the following information relative to the post-earthquake inspection results and instrumentation data collected as part of the post-earthquake event response:

a) The diked portion of the service water reservoir impoundment is instrumented with eight (8) active open-standpipe piezometers and five (5) settlement monuments. As part of the post-seismic event response, measurements were taken from the respective instrumentation systems and plotted to compare with recent and historical measurements.

b) An examination of the measured pore pressures generally indicated that the levels remained essentially unchanged or decreased. Exceptions were noted in piezometers P-18, P-20, and P-22 where measured increases were less than 0.5 feet to 1.0 foot and were within the range of historic water level fluctuations. A comparison of the measured piezometric levels to the established high water limits stated in the North Anna technical requirements manual indicates that they were all below those limits.

c) Settlement monuments on the embankment indicated movements ranging from 0.048 inches to 0.33 inches since March 2011, with the monuments on the higher areas of the embankment, SM-1 through SM-3, and SM-6, settling from 0.28 inches to 0.33 inches. Based upon the data trends over the prior several years, it is estimated that the earthquake may have caused movements ranging from less than 0.1 inches to approximately 0.3 inches, resulting in an average of approximately 0.25 inches. The UFSAR indicates that the embankment can tolerate the three (3) inches of relative displacement caused by the DBE event.

d) In addition to the instrument measurements, three separate visual inspections conducted along the service water reservoir embankment and appurtenant structures did not reveal any signs of concern that would indicate impending instability or earthquake induced damage such as sloughing, scarping, slumping, bulging, abrupt translation on the upstream and downstream slopes or seeps/boils. The concrete spillway along with the radial and skimmer gates were also inspected and no damage was noted. The inspection on the crest area with particular attention to items that are not typically anchored, such as a block supported maintenance trailer, indicated that they remained stable with no readily observable evidence of shifting, sliding, or toppling.

Considering that (1) no significant physical damage to the service water reservoir was observed during the NAPS post-earthquake inspections; (2) the design-basis stability analysis of the service water reservoir resulted in a minimum safety factor of 1.2 as shown in Table 3.8-14 of the NAPS UFSAR; and (3) the results of instrumentation and settlement readings were within acceptable range, the NRC staff concludes that there is reasonable assurance that the NAPS service water reservoir remains capable of performing its intended design functions.

3.2.2.4 Spent Fuel Pool Structure

In response to the NRC staff's RAI, the licensee, in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), stated that following the August 23, 2011, earthquake, visual inspections of the NAPS spent fuel pool, using an underwater camera, were performed. The results of these visual inspections showed that (1) there was no indication of sliding or contact (i.e., tipping) between adjacent spent fuel rack arrays or between rack arrays and the adjacent spent fuel pool liner wall and (2) the accessible portions of the spent fuel pool liner (i.e., from the top of the pool to the top of the racks) did not show any liner bulging or liner buckling.

The licensee also stated that on August 27, 2011, samples were taken from the tell-drains of the spent fuel pool. These drains are normally sampled every 90 days, but they were sampled four days after the earthquake (i.e., 25 days since the last sampling) for comparison purposes.

No abnormal increases were observed in isotopic activity, leak rate or total collected volume from any of the six tell-tale drain samples taken from the spent fuel pool on August 27, 2011.

Relative to the structural adequacy of the spent fuel pool, the licensee stated that (1) significant design margin exists since the spent fuel pool bulk water temperature at the time of the earthquake was approximately 90 degrees Fahrenheit (°F), which corresponds to the service load temperature conditions. The spent fuel pool has been analyzed for abnormal load temperature conditions, in which the peak spent fuel pool bulk water temperature reaches 170 °F and (2) post-shutdown inspections have confirmed the satisfactory condition of the visible portions of the spent fuel pool structure exterior concrete and liner following the August 23, 2011, earthquake.

As further quantification of the available margin, the licensee performed a review of the stress summary in Table 9A-2 of the NAPS UFSAR, for two critical primary load-carrying areas in the spent fuel pool. This review determined that the maximum stresses in the reinforcing steel in these areas, for load condition of DBE plus abnormal temperature condition, are approximately 75 percent of the allowable stress providing at least 25 percent reserve capacity.

The NRC staff concludes that there is reasonable assurance of no functional damage and that the spent fuel pool remains capable of performing its intended design functions because: (1) the inspection of the spent fuel pool structure did not reveal any sign of structural distress in the spent fuel pool liner and the spent fuel pool racks; (2) no abnormal increases were observed in isotopic activity, leak rate or total collected volume from any of the six tell-tale drain samples taken from the spent fuel pool on August 27, 2011; (3) there is at least 25 percent available design margin for critical areas of the spent fuel pool structure as indicated in the analysis results in Table 9A-2 of the NAPS UFSAR; (4) the recorded response spectra at the containment base mat which is founded on rock, in the range of frequencies most damaging to structures, 2 to 10 Hz, did not exceed the NAPS DBE in the East-West direction, but only exceeded, on average, the North-South direction by about 12 percent and the vertical direction by about 21 percent; and (5) the spent fuel pool structure has been analyzed for abnormal environmental load combination that includes the effects of DBE and abnormal thermal condition in which the peak spent fuel pool water temperature reaches 170 °F. As the water temperature at the time of the August 23, 2011, earthquake was approximately 90 °F, as stated in the licensee's letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), this will provide additional margin since the abnormal thermal condition creates significant compressive strain in the spent fuel pool liner system which in turn results in membrane tensile stresses in the spent fuel pool reinforced concrete elements.

3.2.2.5 Other Areas of Review

a) In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that comprehensive inspections of both non-safety-related and safety-related plant systems were performed on over 80 systems for Unit 1 and over 50 systems for Unit 2. The inspections were performed by qualified engineering personnel trained on identifying seismic related damage. The inspections specifically looked for evidence of:

- differential horizontal and vertical movement between adjacent and/or interconnecting building and structures,
- damage to anchorage,
- signs of excessive vibration or movement of equipment and pipe support components or deformation of dead weight supports and sway bracing,
- damage due to expansion joints and flexible joints,
- damage to passive barriers,
- damage to components due to attached piping, ducts, conduits, and ground straps, and
- damage to pipe at building joints and interfaces between buildings.

The licensee further stated that (1) no concerns with operational gaps were identified during the plant system inspection and (2) no physical or functional damage to plant systems attributable to the August 23, 2011, earthquake that would render them incapable of performing their design functions was identified.

b) The NRC staff requested the licensee to confirm that the inspection and verification of all seismic gaps between structures (e.g., the minimum 2-inch rattle space as noted in Section 3.8.1.1, "Design Basis and Physical Description," of the NAPS UFSAR) in both NAPS Units 1 and 2 have been performed. In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that the NAPS rattle space inspection requirements were accomplished during post-seismic inspections and there were no adverse findings regarding seismic gaps between structures.

c) The NRC staff requested the licensee to discuss the inspection and verification of all components crossing seismic gaps in both NAPS Units 1 and 2, to confirm the relative motion during the August 23, 2011, earthquake was accommodated without any damage or loss of function. In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that those systems that cross the boundaries between independent buildings were inspected and no instances of damage were identified that would render any system nonfunctional.

Relative to the items (a), (b), and (c) above, the NRC staff concludes that there is reasonable assurance that the operational gaps to allow thermal movement of major equipment and piping systems, the components crossing between independent buildings, and the seismic gaps between structures have not been adversely affected by the August 23, 2011, earthquake and thus, these components remain capable of performing their intended design functions because (1) the licensee's comprehensive inspection of both non-safety-related and safety-related plant systems on over 80 systems for Unit 1 and over 50 systems for Unit 2 did not reveal any damage attributable to the August 23, 2011, earthquake; (2) there were no adverse findings regarding seismic gaps between structures; (3) no instances of damage were identified in those systems that cross the boundaries between independent buildings; (4) the NRC inspection team observed no damage or significant movement of SSCs that could be attributed to the August 23, 2011, earthquake; and (5) as stated in its letter dated September 17, 2011 (Serial No. 11-520; Reference 1), the licensee will perform surveillance and functional tests to demonstrate the operability of components and systems important to nuclear safety or required to mitigate the consequences of an accident as required in the plant Technical Specifications.

d) The NRC staff requested the licensee to discuss and provide further information, in reference to Table 3.7-4 and Table 3.7-5 of the NAPS UFSAR, relative to the effects of the August 23, 2011, earthquake on SSCs in these tables and to demonstrate that the affected SSCs will continue to perform their required design functions.

In response to the NRC staff's RAI, the licensee, in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), stated that Table 3.7-4 and Table 3.7-5 of the NAPS UFSAR provide a historical, representative listing of seismic design margins in the original scope of supply of mechanical and structural items and the information in these tables does not reflect the current seismic design margin. The licensee also stated that the operational readiness of the components in these tables were reviewed by inspection and testing.

The licensee performed a detailed review of a sample of components in these tables that have a small reported margin. The results of this detailed evaluation showed that there is a higher design margin than the values listed in these tables. For example, the licensee provided the following information for steam generator (SG), and the reactor coolant pump (RCP) supports:

- For SG supports, the lowest margin reported in Table 3.7-4 was 1.01 as the ratio of allowable stress to the stress due to normal loads (deadweight plus thermal plus internal pressure) plus Square Root Sum of the Squares (SRSS) of DBE and pipe rupture load. The reported margin was for one member in the SG Lower Support. The minimum available margin in the analysis of record for SG lower support is 1.5 in normal loads (deadweight plus thermal plus internal pressure) plus SRSS of DBE and pipe rupture loading condition. In a non-pipe rupture condition with load due to deadweight, pressure, thermal, and DBE, the available margin is 1.9. The minimum available margin in the analysis of record for SG upper support is 1.2 for normal loads (deadweight plus thermal plus

internal pressure) plus SRSS of DBE and pipe rupture loading condition. In a non-pipe rupture condition, the available margin is at least 3.3.

- For RCP supports, Table 3.7-4 reported a margin of 1.21 when subjected to normal load (deadweight plus thermal plus internal pressure) plus SRSS of DBE and pipe rupture loading condition. The analysis of record shows that the margin is at least 1.3. In a non-pipe rupture condition, the available margin is at least 1.5.

- The licensee stated that an analysis of a representative loop of the reactor coolant piping including the SG and RCP was performed using the spectra developed from the recorded time-histories in the containment building. The analysis showed that the load on the SG and RCP support feet for the August 23, 2011, earthquake was less than the load on the SG and RCP support feet due to the DBE.

Relative to item (d) above, the licensee demonstrated that the current analysis/design record for a sample of most highly stressed items indicates design margins higher than the values listed in Table 3.7-4 and Table 3.7-5 of the NAPS UFSAR. Therefore, considering the satisfactory results of the inspections and functional testing, and absence of pipe rupture loading condition during the August 23, 2011, earthquake, there is reasonable assurance that these components remain capable of performing their intended design functions.

e) As stated in Section 3.8.5.4, “Conclusions,” of the NAPS UFSAR, the current differential settlement between the service building and the main steam valve room/quench spray pump house has essentially stabilized. However, monitoring of movement between the two buildings will continue to assure that the differential settlement between them will not exceed 9/16 inches to maintain the stresses in the safety-related service water buried piping within the design-basis code acceptance criteria.

In response to the NRC staff’s RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that the change in differential settlement between the quench spray pump house and the service building prior to and following the August 23, 2011, earthquake was determined to be 0.036 inches. This differential settlement value was compared to the Technical Requirements Manual (TRM) limits used to establish the upper-bound service water pipe stress limits. The post-earthquake differential settlement value was calculated to be 0.24 inches, which is below the TRM limit of 0.564 inches.

Relative to item (e) above, considering that the post-earthquake differential settlement value of 0.24 inches, between the quench spray pump house and the service building, is below the NAPS TRM and the UFSAR limit of 0.564 inches, the NRC staff concludes that there is reasonable assurance that the service water buried piping remains capable of performing its intended design functions. Section 3.1 of this report includes further evaluation of buried piping.

f) The NRC staff requested the licensee to provide further information to confirm that the inspection of all NAPS Units 1 and 2 load handling systems (cranes,

monorails, movable platforms with hoist, etc.) that could potentially affect safety-related SSCs has been performed.

In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that no seismically related structural damage or operational issues were identified on the NAPS load handling systems that were inspected by civil engineering personnel, or during the compliance inspections that were performed on the systems prior to their use.

Considering the response to this RAI, the NRC staff concludes that there is reasonable assurance that the NAPS Units 1 and 2 load handling system remains capable of performing its intended design functions.

g) Tables 1 and 2 of Enclosure 1 to the licensee letter dated September 17, 2011 (Serial No. 11-520; Reference 1), lists those SSCs that were determined to have high confidence of low probability of failure (HCLPF) capacities below 0.3 g. These SSCs were identified during implementation of the NAPS response to Generic Letter (GL) 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE), Accident Vulnerabilities – 10 CFR 50.54(f)," dated June 28, 1991 (Reference 25), and GL 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46," dated February 19, 1987 (Reference 28).

The HCLPF value for majority of these components was based on the anchorage capacity or foundation overturning. The lowest HCLPF values were for emergency condensate storage tanks (0.16 g) and refueling water storage tanks (0.18 g).

In response to the NRC staff's RAI, in its letter dated September 27, 2011 (Serial No. 11-520A; Reference 2), the licensee stated that a detailed inspection of these components has been completed and no physical seismic related damage was identified that would have prevented a component from performing its design function.

Considering that there was no physical damage to the components, including their foundation and anchorages, that are listed in Tables 1 and 2 of Enclosure 1 to the licensee's letter dated September 17, 2011 (Series No. 11-520; Reference 1), the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not adversely affect the foundation and anchorages for these components and thus, they remain capable of performing their intended design functions. For functionality assessment of steam generator blowdown containment isolation valves and 4160 V emergency bus relays, see Section 5.4 and 8.0 of this report, respectively.

h) Section 3.8.1.1.7, "Service Water Pump House," of the NAPS UFSAR discusses the cracks that were discovered in the reinforced concrete wing walls, subsequent modification of the wing walls to decouple these walls from the service water pump house, and a horizontal shear-stress calculation to

demonstrate stress transfer across the crack. The NRC staff requested the licensee to provide further information to confirm the structural adequacy of the wing walls.

In response to the NRC staff's RAI, the licensee stated in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), that the shear transfer at the base of the wing wall was evaluated for the earthquake that occurred on August 23, 2011. This evaluation demonstrated that the section capacity to load demand ratio is 2.7 indicating that the wing walls have adequate capacity to transfer the shear demand associated with the August 23, 2011, earthquake.

Considering that the results of re-evaluation of the wing walls for the seismic loads associated with the August 23, 2011, earthquake shows a margin of 2.7, the NRC staff concludes that there is reasonable assurance that August 23, 2011, earthquake did not adversely affect the intended design function of the reinforced concrete wing walls described in Section 3.8.1.1.7 of the NAPS UFSAR.

i) In response to the NRC staff's RAI, the licensee stated in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), that (1) the inspection of the Unit 2 discharge tunnel was performed and no earthquake related issues were identified and (2) no ground settlement issues or cracks in the soil or roadways were noted around the NAPS.

Considering the licensee's response to the NRC staff's RAI, the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not adversely affect the discharge tunnel structural integrity.

j) As the level of the August 23, 2011, earthquake exceeded the design basis earthquake, the NRC staff requested the licensee to confirm that the concrete anchors will continue to perform their intended design functions.

In response to the NRC staff's RAI, the licensee stated in its letter dated October 18, 2011 (Serial No. 11-577A; Reference 10), that (1) the NAPS design standard for drilled-in concrete anchors uses a safety factor of four to average ultimate capacities for the appropriate embedment depth and concrete strength; (2) any evidence of overloading would be evident in cracking of the concrete around the expansion bolt; (3) extensive engineering inspections were performed of all systems that included piping/equipment supports and anchorage. As a result of these inspections, several condition reports were created for concerns identified with anchorage. However, after evaluation, these concerns could not be categorized as associated with the earthquake; and (4) the effective strong motion duration of the August 23, 2011, earthquake was 3.1 seconds in one direction, with the other two directions being 1.5 and 1.0 seconds. Consequently, this was a relatively short-duration earthquake resulting in relatively few cycles of vibration.

Upon review of the licensee's response submitted by letter dated October 18, 2011, which noted condition reports relative to a few supports with loose

anchors, during a follow-up conference call, the NRC staff requested the licensee to provide further information relative to the extent of condition of concrete anchor's loss of torque.

In its letter dated October 31, 2011 (Serial No. 11-566E; Reference 17), the licensee provided the results of the tightness check of 316 anchor bolts on 51 supports. This tightness check was performed on the supports located in the Unit 2 safeguards building and auxiliary building, and Unit 2 containment. The licensee stated that (1) the selected anchor bolts ranged from ½-inch to 1-1/4-inch diameter in size, and were randomly selected; (2) of the 316 anchor bolts torque tested all but five passed the test; (3) the five that did not pass were wrench tight and were re-torqued, which confirmed proper grip, and maintained full load carrying capability; and (4) the five anchor bolts that did not meet the torque checks were in five different supports. However, the remaining bolts in each support passed the torque check, and the affected support remained tight against the wall, indicating that the five wrench tight bolts were not caused by the August 23, 2011, earthquake.

Based on the response to the NRC staff's RAI, considering (1) low number of cycles of strong motion from the August 23, 2011, earthquake, (2) comprehensive post-earthquake inspections that did not identify any significant damage to the support/component anchorage and its surrounding concrete that could be attributed to the August 23, 2011, earthquake, and (3) the results of the tightness check of 316 concrete anchors in three different safety-related buildings, the NRC staff has reasonable assurance that the intended design function of the concrete anchors was not adversely affected by the August 23, 2011, earthquake.

k) In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that the inspection of the support pads and fire walls for the main generator step-up transformers, the station service transformers, and the reserve station service transformers were completed with only cosmetic damage identified, possibly resulting from the earthquake. No damage was observed that would affect the structural integrity of the components inspected.

l) In response to the NRC staff's RAI, the licensee stated in its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), that the low level and high level liquid waste tanks are suspended through the floor between the 259-foot and 244-foot elevations of the auxiliary building, with the tank supports attached to the floor of the 259-foot elevation. The licensee stated that (1) the supports for these tanks were inspected and no issues were identified; (2) the inspections of associated system components had identified no damage attributable to the recent seismic event; and (3) other piping in this area of the auxiliary building with a similar support structure was inspected and no significant damage was identified.

Relative to items (k) and (l) above, the licensee's response to this RAI provides reasonable assurance that the support structures for these components were not adversely affected by the

August 23, 2011, earthquake and thus, they remain capable of performing their intended design functions.

m) As stated in Section 3.8.4.5.3, “Monitoring of Settlement,” of the NAPS UFSAR, Table 3.8-15 lists the structures which are being monitored for settlement. The NRC staff requested the licensee (1) to provide further information to ensure the acceptability of settlement of these structures considering the baseline survey and the allowable differential settlements and (2) to demonstrate the integrity of the rubber expansion joint installed on the service water piping noted in Section 3.8.4.5.4.5 of the NAPS UFSAR, following the August 23, 2011, earthquake.

In response to the NRC staff’s RAI, the licensee in its letter October 18, 2011 (Serial No. 11-577A; Reference 10), stated that (1) the pump house, valve house, and tie-in vault structures each have four settlement monuments; (2) immediately adjacent to the Pump House structure there are two settlement monuments located on the expansion joint above the service water pipes (as shown in Figure 3.8-60 in the NAPS UFSAR); (3) post-seismic settlement data in these areas was obtained as a part of periodic data collection that had been previously scheduled, then plotted and evaluated to ascertain a quantitative measure of deformation; (4) total deflections through March 2011 in the valve house, pump house, and the tie-in vault averaged 0.348 inches, 2.718 inches, and 0.111 inches, respectively; and (5) post-seismic survey in these areas indicated total deflections averaging 0.480 inches, 2.796 inches, and 0.225 inches, respectively. This reflected an average deflection increase of 0.132 inches, 0.078 inches, and 0.114 inches.

The licensee further stated that (1) monuments SM-17R and SM-18R, located on the service water pipes adjacent to the pump house, are used to monitor movement in the expansion joint installed on the service water piping; (2) the NAPS TRM lists an allowable differential settlement across the expansion joint between monuments SM-17R and SM-18R on the service water pipes and monuments SM-7 and SM-10 in the pump house of 0.220 feet or 2.64 inches. Up through March 2011, the differential settlement across this joint ranged from 0.12 to 0.36 inches and averaged 0.24 inches; (3) post-seismic survey indicated that the differential settlement ranged from 0.11 inches to 0.53 inches and averaged 0.32 inches. These differential settlement values compare favorably with the established TRM limit; and (4) the expansion joints were inspected after the earthquake and no damage was found.

Considering that no damage to the expansion joint in service water piping was observed during post-earthquake inspections, and the post-earthquake settlement data was within acceptable range of the NAPS TRM, the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not create excessive differential settlement between the pump house, the valve house and the tie-in vault structure and thus, these structures remain capable of performing their intended design functions.

n) Table 3.2-1 of the NAPS UFSAR lists the flood protection dike as being designed for the OBE load condition only. For those structures that are only designed for the OBE load condition, the NRC staff requested the licensee to provide further information to confirm their structural integrity.

In response to the NRC staff's RAI, the licensee in its letter October 18, 2011 (Serial No. 11-577A; Reference 10), stated that the DBE load condition was also considered in the original design basis calculation for the flood protection dike. The licensee reviewed the design-basis slope stability analyses and confirmed that, for the DBE load case, the factor of safety is greater than 1.0. The licensee conducted a post-seismic inspection of the dike and steel drainage culvert going through the dike to confirm no damage as a result of the August 23, 2011, earthquake. This inspection revealed no discernable damage or displacement.

Considering the flood protection dike has been designed for both OBE and DBE load conditions and the post-earthquake inspection did not reveal any damage that could be attributed to the August 23, 2011, earthquake, the NRC staff concludes that there is reasonable assurance that the flood protection dike has not been adversely affected by the August 23, 2011, earthquake and thus, it remains capable of performing its intended design functions.

o) In response to the NRC staff's RAI, the licensee in its letter dated October 31, 2011 (Serial No. 11-566E; Reference 17), provided information relative to the NAPS battery rack design margins.

The licensee stated that (1) the main station batteries are supported by two-tier battery racks. These racks are located in the cable spreading room and emergency switchgear room, at elevation 254 [foot] and 294 [foot] of the service building, respectively; (2) the main station battery rack structural analysis used peak spectral accelerations corresponding to 0.5 percent of critical damping for the OBE load condition and 1 percent for the DBE load condition. However, consistent with the NAPS licensing basis, the use of 3 percent damping would have been acceptable; (3) the main station battery rack structural analysis conservatively used OBE condition stress allowable limits as acceptance criteria for structural member stresses for enveloped OBE and DBE level loads, limiting member stresses to 75 percent of yield; (4) the anchorage for the main station battery racks was evaluated for the IPEEE review level earthquake anchored at 0.3 g and its associated in-structure response spectra for the 294-foot elevation of the service building and found acceptable; (5) the emergency diesel generator (EDG) batteries are located in the EDG rooms at the 275-foot elevation of the service building; (6) the fundamental frequency of the EDG battery racks is in the rigid range but they have been conservatively analyzed using a multimodal factor

> of 1.5 times the maximum spectral accelerations between 33 Hz and 100 Hz; and (7) post-earthquake inspections did not identify any damage to the batteries, the racks, or the rack's anchorage.

Considering the information provided above relative to the conservative design parameters used in the analysis of the main station and the EDG battery racks, and the results of the post-earthquake inspections that did not identify any damage to the racks and their anchorage, the NRC staff concludes that there is reasonable assurance that the August 23, 2011, earthquake did not adversely affect the intended design function of these battery racks.

3.2.3 Conclusion

Based on the above evaluation, the NRC staff concludes that the licensee demonstrated, through walkdowns of all seismic Class I structures and evaluations of selected structures and components, that seismic Class I structures at the NAPS Units 1 and 2 remain capable of performing their intended design functions. The NRC inspection activities also support this conclusion that no significant damage to seismic Class I structures has been observed that could be attributed to the August 23, 2011, earthquake.

3.3 Snubbers

3.3.1 Description of the Licensee's Evaluation and Actions

The licensee stated in its submittal letter dated September 17, 2011, Enclosure 2 (Serial No. 11-520; Reference 1), in part, that:

> Initial visual inspections were performed by engineering personnel immediately following the August 23, 2011, earthquake, and the subsequent aftershocks up to August 26, 2011. The damage discovered during these inspections did not identify any significant physical or functional damage to safety-related structures, systems and components (SSCs) and only limited damage to non-safety-related, non-seismically designed SSCs. Condition Reports (CRs) were submitted for the identified discrepancies. The results of these and additional focused inspections supported an EPRI Damage Intensity of 0, which is defined in Table 2-1 in EPRI NP-6695.

The licensee also stated that, to confirm the EPRI Damage Intensity, conservative measures were taken to perform comprehensive and methodical expanded inspections of the plant to further assess the impact of the earthquake on plant SSCs. The expanded inspections performed as part of the post-shutdown actions are defined in EPRI NP-6695. Surveillance tests required by the TS will be completed prior to Unit 1 and 2 startups, respectively, to further demonstrate that SSCs can perform their design functions.

Additionally, the licensee documented that:

> The structural component inspections consisted of safety-related and non-safety-related structural components that meet regulatory requirements for Maintenance Rule and contribute to the operation of the station. These components are

> identified in procedure ER-NA-INS-104, 'Monitoring of Structures North Anna Power Station,' and the inspections were performed in accordance with this procedure. Attachment 8 of ER-NA-INS-104, 'Seismic Event Inspection,' was created based on the EPRI-NP-6695 guidelines and details the inspections to be performed on concrete structures, steel structures, and low pressure tanks. The inspection team looked for significant physical or functional damage caused by the earthquake that exceeded the acceptance criteria. The acceptance criteria are defined in procedure ER-NA-INS-104 and meet the guidelines established in EPRI NP-6695. The inspection results were documented in accordance with procedural requirements. The inspections were performed by qualified engineering personnel as defined in ER-NA-INS-104.

In responses to requests for additional information (RAIs) from the NRC, the licensee provided the following details in its letters dated October 3, 2011, October 10, 2011 (2), and October 18, 2011, about inspections of piping system and visual examinations and testing of snubbers:

The licensee noted that that there are 326 safety-related snubbers for Unit 1 and 362 safety-related snubbers for Unit 2. Each Unit 1 and Unit 2 snubber was visually inspected by qualified engineers (Level II) using VT-3 examination. The NRC noted that a Level II-qualified engineer is someone who has completed the ANSI/ASNT CP-189, Level II Required Examination. VT-3 examinations are conducted per the ASME Code, Section XI, Paragraph IWA-2213 to determine the general mechanical and structure condition of components.

The licensee stated the following:

> Comprehensive inspections of both non-safety-related and safety-related plant piping systems were performed on over 80 systems for Unit 1 (which includes common systems [between two units]) and over 50 systems for Unit 2. These inspections were performed in accordance with NAPS station procedure 0-GEP-30, "Post Seismic Event System Engineering Walkdown," which was developed using the guidance provided in EPRI NP-6695. Inspection results were documented in procedure inspection logs, and discrepancies were entered into the NAPS Corrective Action System. The inspections were performed by qualified engineering personnel trained on identifying seismic related damage. The inspections did not identify any physical or functional damage to the piping systems, as a result of the August 23, 2011, earthquake, that would render them incapable of performing their design functions.
>
> While not specifically identified in the inspection procedure, piping system inspections encompassed pipe welds, nozzles, flanges, attachment lugs, couplings, etc. In addition, procedure, 0-GEP-30, included the following specific guidance for performing piping inspections:
>
> - Check for snubber damage (i.e., snubbers pulled loose from foundation bolts, leakage of hydraulic fluid and bent piston rods)
> - Check for damage at rigid supports (i.e., deformation of support structure, deformation of pipe due to impact to support structure)
> - Check for damage of expansion joints

- Check for damage or leakage of piping and branch lines
- Check for damage to pipe at building joints and interfaces between buildings

Inaccessible and insulated portions of piping systems were dispositioned based on inspections of associated system components that resulted in no significant damage attributable to the recent seismic event and or other piping in the same building or structure with similar supports that was inspected with satisfactory results.

There were no unacceptable or damaged piping systems identified during the system inspections.

According to the licensee, all snubbers at NAPS are hydraulic snubbers. Typically, hydraulic snubbers do not fail in a locked condition. Visual inspections of snubbers included checking the snubbers for freedom of movement, where possible, without disconnecting the snubber. Several snubbers had deficiencies identified during the visual exam and required further evaluation. Some of the snubbers required functional testing to confirm their operational readiness.

On Unit 1, five snubbers were bench tested to confirm functionality due to low-fluid levels being identified. Six additional Unit 1 snubbers were identified as needing cleaning (oil on snubber) or minor repair (one pipe clamp needed to be slightly rotated on the pipe). These issues did not impact functionality, but were evaluated and addressed. These visual inspection results were consistent with the previous visual inspection performed at Unit 1 snubbers during the refueling outage in the spring of 2009.

On Unit 2, five snubbers were removed for bench testing due to low-fluid levels being identified and all were tested with satisfactory results. In addition, one snubber was replaced due to a suspected oil leak, although the snubber had adequate fluid during the visual inspection. The snubber was subsequently functionally tested with satisfactory results. One snubber was identified with a rotated pipe clamp. This was repaired (aligned) and the snubber was functionally tested with satisfactory results. One snubber was identified with a bent attachment lug. Inspection by NAPS engineering determined that the damage (bent attachment) appeared to be caused by application of a lateral load and was not due to the earthquake. The attachment lug was repaired and the associated snubber was replaced and functionally tested with satisfactory results. These visual inspection results were consistent with the previous visual inspections performed on Unit 2 snubbers during the in refueling outage in the spring of 2010.

Functional testing of the Unit 2 snubbers was performed in accordance with the normal refueling outage procedure. The licensee used the Technical Requirement Manual (TRM) 3.7.5 requirements for snubber examination and functional testing. For Unit 2, 60 small-bore snubbers and two large-bore snubbers were functionally tested, to meet the TRM requirements. No test failures were identified. The snubbers tested, due to visual inspection deficiencies, were not included in the required functional test group to meet the TRM requirements.

By letter dated October 3, 2011, the licensee stated, in the response to NRC questions that,

> Unit 1 and Unit 2 are similarly designed and constructed plants. The piping systems are similarly arranged and supported. Both units are on the same elevations and have similar design response spectra. Both units experienced similar ground motion from the seismic event. Based on these similarities in design and construction, it is expected that snubbers on both units were impacted by the earthquake similarly. Therefore, functional test results for Unit 2 are representative for Unit 1. Any functional test failure requires a cause evaluation in accordance with our corrective action system.

In response to additional RAIs from the NRC, the licensee chose to functionally test an additional sample of 12 small-bore snubbers and two large-bore snubbers from Unit 1. All test results were found to be satisfactory. The Unit 1 sample was developed based on a combination of various buildings/elevations, the ease of access (based on As Low As Is Reasonably Achievable (ALARA), scaffold concerns, etc.), and snubbers that were identified as possibly experiencing high loading during a seismic event. Further, the licensee stated that sample snubbers for Unit 1 were selected based on the existing piping stress analysis and snubbers that were most likely loaded during the August 23, 2011, earthquake.

In a response to additional follow-up RAIs from NRC, the licensee stated in letter dated October 28, 2011, in part, that

> Snubber load acceptance criteria are based on allowable design load criteria. For small bore hydraulic snubbers used at NAPS, the allowable design load is typically 30% to 50% less than the faulted allowable loading provided by the manufacturer. Even if the assumption is made that the August 23, 2011, earthquake fully developed design type loading conditions in the piping systems, and assuming that those loads were 20% above the design basis earthquake loading, there is still substantial margin available to snubber failure. Furthermore, snubbers are available in discrete sizes, with discrete allowable loads. It is NAPS's practice to select the next larger size snubber based on the calculated design load. The difference between the calculated design load and load rating of the next largest size snubber provides additional margin to the maximum capability of a snubber. Based on the above, no additional analysis is required to ensure snubber design is adequate.

3.3.2 NRC Staff Evaluation of Licensee Evaluation and Actions

Snubbers are essentially restraining devices used to control the movement of pipe and equipment during abnormal dynamic conditions, such as earthquakes, turbine trips, safety/relief valve discharges, and rapid valve closures. The design of a snubber allows free thermal movement of a component during normal operating conditions, but restraints the component in off-normal conditions, including earthquake.

Following the August 23, 2011, earthquake, the licensee decided to begin the refueling outage of NAPS, Unit 2, rather than restart the unit. Based on the required examination and testing during refueling outages, the licensee performed the fourth 10-year interval inservice

examinations and testing of Unit 2 snubbers, per TRM Section 3.7.5. The licensee discussed the results of the examinations in its letter dated October 3, 2011. The examinations and tests performed on Unit 2 were as follows:

- Visual Examination of all the small bore and large bore snubbers at NAPS Unit 2
- Functional testing of 10 percent of the snubbers as required by TRM

For Unit 1, the licensee performed the following examinations and tests:

- Visual inspection of all the small bore and large bore snubbers at NAPS Unit 1
- Functional testing of 12 small bore snubbers and two large bore snubbers at Unit 1

During the above visual examinations of all the NAPS Unit 1 and 2 small-bore and large-bore snubbers, the licensee did not find any significant damage attributable to the August 23, 2011, earthquake. The licensee noted minor discrepancies identified during the examinations in its Corrective Action system. For Unit 2, the licensee performed functional sample testing of 60 small-bore and two large-bore snubbers, without any functional testing failures. All Unit 1 snubbers that were functionally tested also passed.

NAPS, Units 1 and 2 are similarly designed and constructed plants, with equipment in each unit at the same elevations. Both units experienced similar ground motion during the seismic event on August 23, 2011. Based on the similarities between Unit 1 and Unit 2, the NRC staff reasoned that snubbers on both units were impacted by the earthquake in the same manner. Additionally, for all small-bore snubbers at NAPS, the allowable design load is typically 30 to 50 percent less than the faulted allowable loading provided by the manufacturer. Based on these facts, the NRC staff concluded that the sample of snubbers functionally tested in Units 1 and 2 were sufficient to ensure the operational readiness of all of the snubbers in each unit.

On October 3, 2011, an NRC Augmented Inspection Team (AIT) completed an inspection of NAPS, Units 1 and 2, as documented in an NRC inspection report dated October 31, 2011 (Reference 30). No significant damage was observed to any of the components, including snubbers, at the plant. A post-earthquake walkdown inspection of snubbers, along with pipe supports and hangers, was conducted by the NRC's Region II staff's "Post-Earthquake Restart Readiness Review Team." No significant damage that could be attributed to the August 23, 2011, earthquake was indentified for any snubbers during these walkdowns. This confirmed the findings made from comparable visual inspections conducted by the licensee.

The NRC staff reviewed the licensee's information and the results from the inspections noted above, and determined that the licensee satisfied RG 1.167, EPRI-NP 6695, and ASME Code criteria. This information and inspection results verified the operational readiness of snubbers at NAPS Unit 1 and 2. The NRC staff is satisfied with the licensee's scope of visual inspections and sample functional testing of snubbers and determined that this approach meets the intent of the ASME Code requirements for operational readiness.

3.3.3 Conclusion

Based on information and analysis noted above, including the results of the detailed walkdown inspections conducted by the NRC AIT, NRC Region II Readiness Restart Review team, and the licensee's personnel, the NRC staff determined that no functional damage has occurred to snubbers at NAPS, Units 1 and 2. Therefore, the NRC staff concludes that the resumption of plant operation will not result in undue risk to the health and safety of the public.

4.0 NUCLEAR FUEL

4.1 Nuclear Fuel Performance

At the time of the seismic event on August 23, 2011, the NAPS, Unit 1 and 2, reactor cores were comprised of a single AREVA fuel assembly design known as the Advanced Mark-BW. The Unit 1 and Unit 2 RCS coolant activity measurements following shutdown provided no indication of any fuel failures as a result of the seismic event (See RAI No. 5 of Serial No. 11-544; Reference 3). Nevertheless, fuel assemblies present in the reactor cores, spent fuel pool, and new fuel storage area require analysis and/or inspection to confirm that no damage occurred and that these fuel assemblies could be reused in future operations.

To support a safety finding on the impact of the seismic event on the fuel assembly components, the NRC staff conducted an audit of the post-seismic fuel inspections at the NAPS located at Mineral, Virginia, on September 19–22, 2011. The purpose of the NAPS audit was (1) to discuss the scope of the post-seismic fuel inspection along with the procedures and criteria for judging the condition of the fuel assemblies, and (2) to witness the actual pool-side inspections to understand the capabilities of these inspections to identify fuel damage in support of NRC review of the licensee's restart submittal. A second audit was conducted on October 18, 2011, at the Westinghouse Rockville offices. The purpose of this audit was to review the Westinghouse and AREVA engineering calculations supporting the licensee's response to RAI No. 1 in Serial No. 11-544B (Reference 9).

RG 1.167 and EPRI report NP-6695 provide little guidance with respect to evaluating potential damage to and continued operation of fuel assemblies. The NRC staff's strategy for assessing fuel assembly damage and judging continued operation of the fuel assemblies present on-site at the time of the seismic event is summarized below:

1. Review staff's prior approval of AREVA Advanced Mark-BW fuel assembly topical report to understand its design and licensing basis.

2. Review AREVA's mechanical design engineering calculations to understand the load carrying capability of each component in the Advanced Mark-BW fuel assembly design.

    - Review the grid crush test reports to understand the buckling force, failure point (e.g., weakest location on grid cage), and progression of deformation of the Advanced Mark-BW grid cage designs when subjected to external loads prototypical of a seismic event.

3. Request translation of the August 23, 2011, measured ground motion into dynamic core support plate motion and resulting fuel assembly accelerations.

4. Request calculation of stresses and loads on fuel assembly components based on predicted accelerations from August 23, 2011, measured ground motion from item no. 3.

5. Compare calculated stresses and loads from item no. 4 against allowable limits from item no. 2 to determine likelihood of damage or deformation of assembly components.

   - Compare measured buckling force for each grid cage design and guide tubes (item no. 2) against predicted seismic loads (item no. 4) to determine likelihood of deformation to grid cage and guide tubes.

6. Review scope of planned post-seismic fuel inspections, audit site procedures for conducting visual inspections along with criteria for judging the condition of the fuel assemblies, and witness actual pool-side inspections to understand the capabilities of these inspections (e.g., camera resolution) to identify fuel assembly component damage or deformation.

7. Compare grid deformation characteristics from item no. 2 against inspection capabilities from item no. 6 to judge effectiveness of visual inspections to identify damage or deformation.

8. Review video images of post-seismic fuel visual inspections for (1) signs of trauma indicative of assembly-to-assembly or assembly-to-baffle impact due to horizontal acceleration, and (2) damage to or depression of assembly spring due to vertical acceleration.

9. Review scope of planned post-seismic rod cluster control assemblies (RCCAs) guide tube inspections, audit site procedures for conducting RCCA drag tests along with criteria for judging the condition of the guide tubes, and witness actual pool-side RCCA drag tests to understand the capabilities of these inspections (e.g., measured drag load) to identify guide tube deformation.

10. Compare measured RCCA drag loads against expected loads on non-deformed guide tubes.

11. In addition to potentially different local accelerations resulting from the seismic event, different clearances exist between the fuel assembly perimeter and (1) cell walls of the spent fuel racks, (2) cell walls of the new fuel storage cell, and (3) in-reactor neighboring assemblies and core shroud. Review scope of post-seismic fuel inspections on fuel at each location.

12. To support continued operation, ensure that any predicted grid cage deformation resulting from the combined predicted seismic loads from item no. 3 and previously estimated loss-of-coolant accident (LOCA) loads are properly

accounted for in emergency core cooling system (ECCS) performance and safety analyses.

13. Review planned inspection and testing during plant start-up to confirm operability and functionality of the CRDM and RCCAs.

The following sections address each of the above items:

Advanced Mark-BW Fuel Assembly Design and Licensing Basis:

Regulatory guidance for the review of fuel system designs and adherence to applicable General Design Criteria (GDC) is provided in SRP Section 4.2, "Fuel System Design." In accordance with SRP Section 4.2, the objectives of the fuel system safety review are to provide assurance that:

1. the fuel system is not damaged as a result of normal operation and anticipated operational occurrences (AOOs),

2. fuel system damage is never so severe as to prevent control rod insertion when it is required,

3. the number of fuel rod failures is not underestimated for postulated accidents, and

4. coolability is always maintained.

Specific guidance with respect to fuel performance requirements for externally applied loads including seismic events is provided in Appendix A of SRP Section 4.2.

AREVA proprietary topical report BAW-10239(P)-A entitled, "Advanced Mark-BW Fuel Assembly Mechanical Design Topical Report," July 2004, including the NRC staff's safety evaluation, provides the design basis of this fuel assembly design. Section 5.3.4 of BAW-10239(P)-A defines design criteria with respect to structural damage from external forces, including seismic requirements:

Operational Basis Earthquake (OBE):

- Allow continued safe operation of the fuel assembly following an OBE event by ensuring the fuel assembly components do not violate their dimensional requirements.

Safe Shutdown Earthquake (SSE)/Design Basis Earthquake (DBE):

- Ensure safe shutdown of the reactor by maintaining the overall structural integrity of the fuel assemblies, control rod insertability, and a coolable geometry within the deformation limits consistent with the ECCS and safety analysis.

LOCA or SSE+LOCA:

- Ensure safe shutdown of the reactor by maintaining the overall structural integrity of the fuel assemblies and a coolable geometry within deformation limits consistent with the ECCS and safety analysis.

Seismic analyses conclude that the maximum grid impact forces occur at intermediate grid locations of peripheral fuel assemblies adjacent to the core baffle. The example case in BAW-10239(P)-A predicted no plastic deformation in the spacer grids when subjected to OBE and SSE loads. However, a limited amount of plastic deformation was measured on both intermediate spacer grids and intermediate flow mixing grids (IFMs) for the combined SSE+LOCA impact force. BAW-10239(P)-A concludes that the fuel assembly accumulated deformations under SSE+LOCA conditions were evaluated for core coolable geometry and found to be acceptable. The NAPS UFSAR summarizes the current licensing basis with respect to coolable core geometry as follows:

> UFSAR Section 15.4.1.15, Large Break LOCA Core Geometry
>
> Calculations performed for NAPS, Units 1 and 2 indicate that deformation of the fuel pin lattice in some core periphery fuel assemblies occurs from the combined mechanical LOCA and seismic loads (Reference 63, Section 3.3.3). The predicted deformations have a maximum impact of reducing the sub-channel flow area of one row of pins by 32 percent.
>
> Evaluations of the impact of this amount of flow area reduction on the LOCA performance of fuel pins in the peripheral assemblies were conducted with the following results: (1) The coolant flow within these assemblies is not substantially altered; and (2) The maximum cladding temperature during LOCA for the affected pins remain below 1800°F. This is less than the temperature at which significant metal-water reaction occurs. Hence, these grid deformations do not lead to conditions that interfere with core coolability; nor do they affect the reported PCT [peak clad temperature] or metal-water oxidation results.
>
> The consequences of thermal and mechanical deformation of the fuel assemblies in the core were assessed. The resultant deformed geometry maintains a coolable configuration. The conclusions rely on basic phenomena encountered during LOCA and are equally applicable to the Advanced Mark-BW fuel and the current resident NAIF [North Anna Improved Fuel]. Therefore, the coolable geometry requirements of 10 CFR 50.46 are met, and the core remains amenable to cooling.

The Advanced Mark-BW fuel assembly is designed to maintain its functionality up to the OBE applied loads (plus normal loads). The measured ground motion during the seismic event on August 23, 2011, exceeded the NAPS OBE. As a result, it is possible that horizontal and vertical acceleration at the core support plate and resulting loads applied on the Advanced Mark-BW fuel assemblies resulted in damage or localized plastic deformation. Since the fuel was exposed to a seismic event beyond OBE, additional inspections were performed to ensure the existing design basis is maintained..

The Advanced Mark-BW fuel assembly is designed to maintain a coolable geometry and control rod insertability up to the SSE applied loads. The measured ground motion during the seismic event on August 23, 2011, exceeded the NAPS SSE (also referred to as DBE). As a result, it is possible that horizontal and vertical acceleration at the core support plate and resulting loads applied on the Advanced Mark-BW fuel assemblies resulted in damage or localized plastic deformation. Since the fuel was exposed to a seismic event beyond SSE, additional analysis was performed to ensure that the existing design is maintained.

Section 4.1.1 of this safety evaluation addresses the integrity of the fuel assemblies following the seismic event and the actions taken to ensure that the fuel assembly design was not compromised. Section 4.1.2 of this safety evaluation addresses the performance of currently utilized AREVA fuel assemblies during future cycles at NAPS. Section 4.1.3 of this safety evaluation addresses the applicability of Unit 2 fuel inspections to Unit 1 fuel assemblies.

4.1.1 Fuel Assembly Damage Resulting from Seismic Event

To support its review on the impact of the seismic event on the fuel assembly components, on September 14, 2011, the NRC staff issued RAIs related to fuel inspections and predicted loads on the fuel assemblies and reactor internals (Reference 31). Note that these RAIs were issued prior to receipt of the North Anna Restart Readiness Determination Report (References 1 and 2) and that there is considerable overlap in the scope of information provided by the licensee.

As documented in the North Anna Restart Readiness Determination Report, the licensee's approach to assessing damage to the fuel bundles consists of the following:

> Dominion is working with AREVA, the current fuel supplier for North Anna, to assess the margins in the fuel. For this evaluation, the acceptance criterion is that no plastic deformation is predicted. In addition, Dominion – with AREVA's input - has compiled a list of inspections to be conducted for fuel and fuel inserts in the new fuel storage racks and spent fuel pool, and during offload of the Unit 2 core, to verify the acceptability of the Unit 2 fuel for use or reuse. Unit 2 fuel will be examined prior to the Unit 1 startup. The Unit 2 fuel will be used to assess the condition of the Unit 1 fuel. If the Unit 2 fuel meets all of the inspection criteria described herein, no inspections of Unit 1 fuel are planned.

Table 1 of Enclosure 4 of the North Anna Restart Readiness Determination report lists the actions and inspections being conducted to confirm the structural integrity of the fuel assemblies. In response to an RAI regarding fuel inspections to confirm the structural integrity of the grid cage and RCCA guide tubes (RAI No. 2 in Serial Nos. 11-544 and 11-544A; References 3 and 5, respectively), the licensee provided a detailed description of the planned fuel inspections. These inspections are summarized below:

Fuel Inspections:

1. Visual examination with binoculars of all fuel assemblies during Unit 2, Cycle 21 core offload.

2. Visual examination with video camera of a subset of Unit 2, Cycle 21 fuel assemblies including fuel residing in limiting seismic core locations.

3. RCCA drag testing on all rodded assemblies in Unit 2, Cycle 2.

4 RCCA drag testing on all rodded assemblies to be re-inserted in Unit 2, Cycle 22.

5 RCCA drag testing on 7 new fuel assemblies which were in the new fuel storage area during the seismic event.

6. Hot rod drop testing in Unit 1 prior to Cycle 22 restart.

7. Hot rod drop testing in Unit 2 prior to Cycle 22 startup.

8. Visual examination of 18 new fuel assemblies and 11 burnable poison rod assemblies (BPRA) which were in the new fuel storage area during the seismic event.

9. Visual examination with video camera of 10 high burnup fuel assemblies and 5 new fuel assemblies which were in the spent fuel pool during seismic event.

Predicted Fuel Assembly Component Damage:

At the NRC staff's request, the licensee (working with Westinghouse) translated the August 23, 2011, measured ground motion into dynamic core support plate motion and provided this information to AREVA in order to calculate resulting fuel assembly accelerations. Table 1 lists the predicted core support plate horizontal displacement based on the August 23, 2011, measured ground motion. In response to RAI No. 1 in Series No. 11-544B (Reference 9), the licensee provided the result of fuel assembly component design calculations performed by AREVA using dynamic core plate motions calculated by Westinghouse using the recorded time-history ground motion from the August 23, 2011, seismic event. These calculations demonstrate that stresses on the guide thimble and fuel rods remained below allowable limits and that applied loads on the grid cages remained below the critical buckling force.

On October 18, 2011, the NRC staff conducted an audit of the Westinghouse and AREVA engineering calculations supporting the response to RAI No. 1. In AREVA calculation 32-9170782-000, the original Advanced Mark-BW mechanical design calculations were repeated using the August 23, 2011, fuel assembly accelerations in place of the NAPS OBE fuel assembly accelerations. These calculations demonstrate positive margin to the allowable stress limits for each of the fuel assembly components. Hence, no damage or deformation would be predicted for the Advanced Mark-BW fuel assembly as a result of the August 23, 2011, earthquake.

Visual Inspections:

On September 19–22, 2011, the NRC staff conducted an on-site audit to (1) discuss the scope of the post-seismic fuel inspection along with the procedures and criteria for judging the condition of the fuel assemblies, and (2) witness the actual pool-side inspections to understand the capabilities of these inspections to identify fuel damage in support of NRC review of the

licensee's restart submittal. The NRC staff's audit report (Reference 36) summarizes the NRC staff's observations and impressions of NAPS's post-seismic fuel inspection procedures and capabilities as follows:

> At each grid location on all four faces of the assembly, the grid would be viewed from below (looking upward at approximately 45° angle), from straight away, and from above (looking downward at approximately 45° angle). The techniques and equipment employed during the visual fuel inspections are capable of identifying (1) anomalies along peripheral fuel rods and grid straps, (2) anomalies in the top and bottom nozzles, (3) rod bow, and (4) gross lattice deformation.

During the audit, the NRC staff reviewed AREVA's mechanical design engineering calculations, including grid crush test reports, to understand the buckling force, failure point (i.e., weakest location on grid cage), and progression of deformation of the Advanced Mark-BW grid cage designs when subjected to external loads prototypical of a seismic event. As evident in the crush test photos included in the audit report, the entire grid cage structure buckles near the center plane, perpendicular to the applied load. Individual grid straps do not appear to break or deform independent of the entire grid structure and the outer grid strap deforms proportional to interior straps. As a result of this observation, the audit concluded that the detailed visual inspection of the fuel assembly and outer grid strap conducted at NAPS would be capable of identifying grid buckling and deformation of the fuel rod lattice array.

During the audit, the NRC staff reviewed the procedures for performing the video inspection and witnessed several of these inspections at the NAPS Anna spent fuel pool (SFP). In addition, the NRC staff viewed the video recordings on several of the inspected bundles – targeting assemblies residing in the limiting seismic core locations. The NRC staff's inspections of fuel assemblies which were in the Unit 2 reactor during the seismic event identified no signs of trauma which would indicate assembly-to-assembly or assembly-to-baffle impact loading due to seismic acceleration. This finding is consistent with the licensee's conclusion from its broader inspection campaign which concluded (RAI No. 2 in Serial No. 11-544; Reference 3).

> There were no indications of grid, fuel rod or fuel assembly deformation or damage. If the vertical acceleration had been sufficient to lift the core and compress the top nozzle hold down springs, some indications might have appeared on the springs or on the corner pads if the spring bottomed out. Inspections of the side of the nozzle when the video inspections were performed did not identify any such damage to the nozzles.

In addition to potentially different local accelerations resulting from the seismic event, different clearances exist between the fuel assembly perimeter and (1) cell walls of the spent fuel racks, (2) cell walls of the new fuel storage cell, and (3) in-reactor neighboring assemblies and core shroud which necessitate further inspection. As described above, visual inspections were performed on fuel assemblies which resided in both the new fuel storage area and spent fuel pool during the seismic event. Visual inspections were also conducted on the BPRA within the new fuel.

Based upon its scope and the NRC staff's audit of the procedures and assessment of capabilities, the NRC staff is satisfied with the visual inspections performed on the fuel assemblies.

Based on no predicted fuel assembly component damage or deformation (based on August 23rd measured ground motion) and lack of any visual indications of damage or deformation, which would indicate assembly-to-assembly or assembly-to-baffle impact loading due to horizontal acceleration or damage to or depression of assembly springs due to vertical acceleration, the NRC staff finds that the licensee has performed the necessary calculations and inspections to ensure that the fuel assembly components were not damaged as a result of the August 23, 2011, seismic event. Based on the above, the NRC staff concludes that the licensee has demonstrated that no functional damage occurred to the fuel assembly components.

Guide Tube and RCCA Inspections and Testing:

As documented in the North Anna Restart Readiness Determination Report, the licensee's approach to assessing damage to the fuel assembly guide tubes and RCCA rodlets consists of visual inspection, RCCA drag load measurements, and hot rod drop testing. The following was extracted from this report:

> When the units tripped during the recent seismic event, all control rods fully inserted. However, testing will be performed to confirm that the rod cluster control assemblies (RCCAs) still freely travel within the fuel assembly guide tubes. After the Unit 2 offload, the RCCA drag loads will be measured in the spent fuel pool to assess whether the fuel assembly or the RCCAs have any distortion. Post-latch drag testing and hot rod drops of the RCCAs are already required as part of the normal start-up activities and will insure that the RCCAs and CRDMs are functional. A video inspection of the RCCA central hubs will be performed to provide additional confirmation of RCCA integrity. A satisfactory assessment of the Unit 2 RCCAs (rod drag measurements and spent fuel pool video inspections) will provide assurance that the Unit 1 RCCAs are in a similar condition. Although normally required only at [beginning-of-cycle] BOC, hot rod drop testing of the Unit 1 RCCAs in accordance with normal station procedures will be performed prior to the restart of Unit 1 to confirm the continued acceptable condition of the Unit 1 RCCAs.

During the audit, the NRC staff reviewed the procedures for performing the RCCA drag tests and witnessed several of these tests at the NAPS SFP. The results of the RCCA drag testing is presented in response to RAI No. 2 in Serial No. 11-544A (Reference 5). Based on these test results relative to previous cycle measurements, the licensee concluded that there has been no seismic-induced impact on the RCCAs, and no distortion of the fuel assembly guide tubes beyond the normal bow that is expected with Advanced Mark-BW fuel assemblies. Drag tests were also performed on several new fuel assemblies.

Post-latch drag testing and hot rod drops of the RCCAs are already required as part of the normal start-up activities and will be performed on Unit 2 prior to the unit entering Mode 2. In addition, hot rod drops of the RCCAs will be performed on Unit 1 prior to entering Mode 2. These tests ensure the proper alignment of the RCCAs and fuel assemblies, ensure that the

RCCAs move freely, ensure that the control rod drive mechanisms are functional, and verify that the Technical Specification scram insertion time requirements are satisfied.

Based upon no predicted guide tube damage or deformation (based on the August 23, 2011, measured ground motion) and the scope of inspections, including the RCCA drag testing and scheduled BOC post-latch drag testing and hot rod drops testing, the NRC staff is satisfied with the degree of validation that the RCCA rodlets and fuel assembly guide tubes are capable of performing their intended function.

In response to an RAI regarding fuel inspections to confirm the thermal-hydraulic performance of the grid cage mixing vanes (RAI No. 3 in Serial No. 11-544A; Reference 5), the licensee referred to the grid cage design, deformation characteristics (from crush tests), pool-side inspections, and revised mechanical design calculations (concluded that spacer grids remained within elastic region) to support their assertion that the fuel thermal-hydraulic behavior was not impacted by the August 23, 2011, seismic event. Based upon the above assessment, the NRC staff finds this response acceptable.

In response to an RAI regarding control rod drive mechanism inspections (See RAI No. 4 in Serial No. 11-544; Reference 3), the licensee describes required surveillance tests (i.e., Surveillance Requirement (SR) 3.1.4.2 and SR 3.1.4.3) and the logic timing and current order testing which would be completed to ensure operability of the control rod drive system.

In response to an RAI regarding inspections of reactor vessel internals (RAI No. 8 in Serial No. 11-544A; Reference 5), the licensee stated that, while not required by EPRI NP-6695 for Intensity 0 earthquakes, several additional inspections (beyond Enclosure 3 of Reference 1) were identified in collaboration with Westinghouse (Nuclear Steam Supply System (NSSS) vendor). The NRC staff has reviewed the scope of reactor vessel internals (RVI) inspections outlined in response to RAI No. 8 and finds them acceptable for confirming that the RVIs remain capable of performing their design-basis functions.

4.1.2 Future Performance of Fuel Currently Used at NAPS

The Advanced Mark-BW fuel assembly components, currently in use at NAPS, are designed to withstand applied loads up to the OBE without damage or deformation. With respect to the SSE, the assembly is designed to maintain the overall structural integrity, control rod insertability, and grid cage deformation within analyzed limits to ensure a coolable geometry. However, since the August 23, 2011, earthquake exceeded NAPS's OBE and SSE, additional analysis was performed to ensure that the design basis is maintained.

The revised design calculations and post-seismic fuel inspection program performed by the licensee provide assurance that the fuel assemblies present at NAPS were not damaged during the seismic event. Since these revised design calculations demonstrate that no damage or deformation would be predicted for any assembly component during normal operation including the August 23, 2011, core plate motion (in place of NAPS's OBE core plate motion), the future use of Advanced Mark-BW assemblies at NAPS has been verified for normal operation including an earthquake equal to the seismic event on August 23, 2011.

Fuel assemblies must be designed to maintain a coolable geometry, within deformation limits assumed in the ECCS analysis, when subjected to combined SSE+LOCA loads. In response to an RAI regarding combined SSE+LOCA loads (RAI No. 1 in Serial No. 11-544B; Reference 9), the licensee compared the current design basis combined SSE+LOCA core plate motions against the August 23, 2011, earthquake plus LOCA core plate motions and concluded that the current design basis combined SSE+LOCA loads remain bounding. In its response to RAI No. 1, the licensee stated:

> DBE plus LOCA is bounding due to the maximum LOCA load occurring primarily in the East/West direction and the August 23, 2011, earthquake occurring primarily in the North/South direction.

Figure 1 illustrates the orientation of the NAPS reactor cores including the X axis (0° – 180° orientation) and Z axis (90° – 270° orientation). Table 1 lists the predicted core support plate horizontal displacements based on the LOCA, DBE, and August 23, 2011, measured ground motion. Examination of Table 1 reveals that the maximum LOCA displacement occurs along the Z axis which closely aligns with one of the cold legs, whereas, the August 23, 2011, seismic event was strongly oriented along the X axis. Examination of Table 1 also reveals that the DBE horizontal displacement along the Z axis is significantly larger than those for the August 23, 2011, seismic event. This information supports the licensee's statement that the combined SSE+LOCA loads remain bounding. This information also confirms that the maximum lateral forces applied to the fuel during the August 23, 2011, seismic event exceeded those associated with the NAPS DBE.

Based on the information provided in response to RAI No. 1, the NRC staff finds that the performance of the AREVA Advanced Mark-BW fuel assemblies during future normal operation and postulated accidents, including an earthquake equal to the August 23, 2011, seismic event, remains acceptable.

4.1.3 Applicability of Unit 2 Fuel Inspections to Unit 1 Fuel Assemblies

As documented in the North Anna Restart Readiness Determination Report, the licensee's approach to assessing the condition of fuel assemblies which were in the Unit 1 reactor during the seismic event relies upon inspection and testing of Unit 2 fuel. The licensee concluded:

> If the Unit 2 fuel meets all of the inspection criteria described herein, no inspections of Unit 1 fuel are planned.

In response to RAI No. 1 in Reference 9, the licensee discussed the symmetric characteristics and proximity of the two reactor cores:

> The fuel assemblies and insert components in NAPS, Unit 1 are the same design as the Unit 2 fuel and insert components that were inspected. Further, Unit 2 is in close proximity to Unit 1 and is oriented 180 degrees from the Unit 1 core. Due to the symmetric characteristics of the core and fuel assemblies, directional dependent forces or motions would impact the Unit 1 and Unit 2 cores in the same manner.

This statement is supported by Figure 1 which illustrates the orientation of the two reactor cores at NAPS.

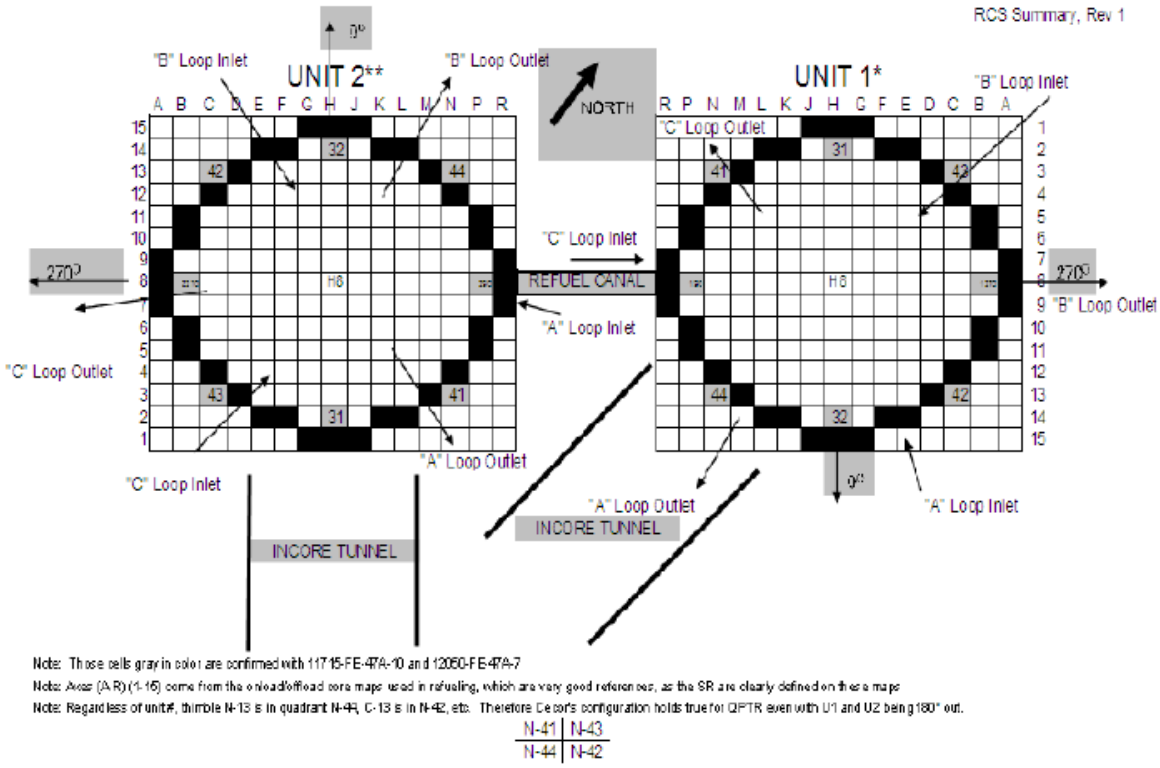
The predicted core support plate horizontal displacements provided in Table 1 for the DBE and August 23, 2011, measured ground motion are applicable to both units. As described above, the AREVA mechanical design calculations demonstrate positive margin to the allowable stress limits for each of the fuel assembly components. Hence, no damage or deformation would be predicted for the Advanced Mark-BW fuel assembly as a result of the August 23, 2011, earthquake in either Unit 1 or Unit 2.

The detailed visual inspections and RCCA drag testing performed on Unit 2 fuel assemblies confirm the conclusions of the revised mechanical design calculations. Therefore, additional confirmatory inspections are not necessary for fuel residing in the Unit 1 reactor.

Table 1: North Anna Peak Core Plate Motion (displacement, inches)
(Source: Westinghouse LTR-RIDA-11-299, Rev. 1)

Location	X-axis (0° – 180° orientation)		Z-axis (90° – 270° orientation)	
	Maximum	**Minimum**	**Maximum**	**Minimum**
LOCA – Accumulator Line Break				
Lower Core Plate	0.0150	-0.0338	0.2931	-0.2376
Upper Core Plate	0.0154	-0.0424	0.3083	-0.3135
Design Basis Earthquake				
Lower Core Plate	0.0426	-0.0464	0.0392	-0.0504
Upper Core Plate	0.0410	-0.0471	0.0423	-0.0535
August 23rd Seismic Event				
Lower Core Plate	0.0659	-0.0745	0.0017	-0.0007
Upper Core Plate	0.0670	-0.0773	0.0033	-0.0025

Figure 1: North Anna Core Orientation
(Source: Attachment 1 of RCE 001061, Revision 1)



Note: On this figure, the spatial orientation is represented by the x-axis along the 0° – 180°direction, the z-axis along the 90° – 270° directions, and the y-axis perpendicular to the page through the center of the reactor core.

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 Reactor Systems

5.1.1 Description of Licensee's Evaluation and Actions

By letter dated September 27, 2011 (Serial No. 11-544; Reference 3), VEPCO provided information concerning its restart evaluation progress and plans related to the RCS.

The licensee provided information in the following topical areas:

- RCS and Main Steam Pressure Relief Capability
- RCS Pressure Boundary Integrity
- Emergency Core Cooling System (ECCS) Component Capability
- Residual Heat Removal (RHR) System Capability

5.1.1.1 Pressure Relief Capability

The licensee stated that several steam generator power operated relief valves (PORVs) were demanded during the reactor trip transient and operated subsequent to the loss of power to the secondary plant at each unit. The valve operation was observed to perform as expected, and the plant primary and secondary cooling systems did not exceed maximum design pressures. The licensee also stated that pressure relief valves were walked down post-event and visually inspected with no damage noted.

Ninety (90) pressure relief valves from Unit 2 are being tested and having preventive maintenance performed on them. Of these, one pressurizer safety valve (PSV) and the five main steam safety valves (MSSVs) from one of the Unit 2 steam generators were sent offsite for as-found testing. This testing indicated that the components lifted within as-found tolerance limits. Further relief valve testing has been performed in accordance with the ASME O&M code. The licensee stated that no adverse trends exist in the present testing, and that no failures attributable to seismic damage were identified.

Finally, the licensee stated that pressure relief loading for relief valves far exceeds the loading from the seismic event.

5.1.1.2 RCS Pressure Boundary Integrity

The licensee stated that it had developed a methodology for performing RCS inspections that was consistent with applicable EPRI guidelines. In addition, in-service inspection nondestructive examination activities have been performed as a part of the Unit 2 refueling outage. Additional inspections of Units 1 and 2 welds for piping and pipe supports including the pressurizer spray line, RCS drain lines, RCS pump seal injection line, and safety injection lines were completed, and no adverse findings were identified. Steam generator tube integrity is discussed in Section 5.2.

5.1.1.3 Emergency Core Cooling System

The licensee observed no anomalies with high-head safety-injection pumps (also normal RCS makeup pumps), which operated throughout the seismic event. The licensee has performed performance testing on low-head safety-injection pumps including tribology and vibration monitoring. No degradation in performance trends was observed.

5.1.1.4 Residual Heat Removal

The licensee stated that Unit 1 RHR was placed in service 1 day following the event, and that Unit 2 RHR was placed in service 2 days following the event. RHR at both units performed as expected with no noted issues or concerns. The licensee compared RHR system performance to historical trending data and stated that no anomalies had been observed.

5.1.1.5 Additional Information

The licensee stated that the sequence of events that occurred following the August 23, 2011, earthquake aligned most similarly to the events described in NAPS UFSAR Chapters 15.2.7,

"Loss of External Electrical Load and/or Turbine Trip," 15.2.9, "Loss of Offsite Power to the Station Auxiliaries," and 15.3.4, "Complete Loss of Reactor Coolant Flow." The plant responded in a matter bounded by the safety analysis results. Limits for adequate core cooling, departure from nucleate boiling protection, reactor coolant and main steam system pressures, and pressurizer level, were not exceeded. The licensing basis events assumed, in most cases, more challenging initial conditions than existed at the plant at the time of the seismic event.

5.1.2 NRC Staff Evaluation

The NRC staff evaluated the information provided by the licensee to determine whether it provided assurance that the plant would respond to upset conditions in a manner bounded by the safety analyses in Chapter 15 of the FSAR. Generally, these analyses require that the RCS pressure boundary remain intact, including steam generator tubes (with the obvious exception of postulated loss-of-coolant accidents and the steam generator tube rupture), that the reactor coolant and main steam pressure relief systems remain capable of lifting, and that the emergency core cooling and RHR systems perform as analyzed. The licensee stated that it was following applicable EPRI guidelines to inspect components forming the RCS pressure boundary. Relief valve testing is being performed in accordance with ASME code requirements, as supplemented by visual inspections. For the purposes of the reactor systems evaluation, the testing and inspections discussed by the licensee provide a reasonable indication that pressure boundary materials and relief valves will remain intact and perform as analyzed. The information provided by the licensee referring to the UFSAR Chapter 15 events and indicating that the plant did not exceed any safety analysis limits following the seismic event provides additional operational assurance in this regard.

The licensee stated that high-head safety-injection pumps were in service and continued to operate following the seismic event. The low-head safety-injection pumps were tested following the event. For both high-head and low-head ECCS components, the licensee stated that no abnormal degradation of pump performance was observed or attributable to seismic damage. Considering both the continued operation of the high-head components and the testing results from the low-head components, the NRC staff concludes that the licensee's inspections and testing has indicated that ECCS components remain capable of performing their intended functions. Based on the fact that RHR systems at both units were placed in service following the seismic event with similar observations – systems performed as expected with no complications – the same conclusions apply to the RHR systems.

5.1.3 Conclusion

As discussed above, the NRC staff reviewed the licensee's description of inspections and evaluations and concludes that the licensee has demonstrated that no functional damage occurred to reactor systems. The licensee's efforts included visual and more detailed inspections, piping inservice inspection and pump inservice testing, and data examination of actual system performance following the seismic event. Based on its review, the NRC concludes that the safety analysis contained in UFSAR Chapter 15 remains applicable to the plant, and supports a conclusion that there was no functional damage to reactor systems that would prevent performance of their safety functions from the August 23, 2011, earthquake.

5.2 Steam Generators

5.2.1 Description of Licensee's Evaluation and Actions

NAPS, Units 1 and Unit 2, each have three recirculating steam generators designed and fabricated by Westinghouse. These steam generators are replacement model 54F and were installed in 1993 and 1995 at Units 1 and 2, respectively. Each steam generator has 3592 thermally treated Alloy 690 tubes with an outside diameter of 0.875 inches and a nominal wall thickness of 0.050 inches. The tubes are hydraulically expanded at each end over the full depth of the tubesheet. The tubes are supported by a flow distribution baffle, support plates, and anti-vibration bars. All supports are constructed from Type 405 stainless steel.

The steam generator tubing functions as an integral part of the reactor coolant pressure boundary, as defined in 10 CFR 50.2, and in addition, serves to isolate radioactive fission products in the primary reactor coolant from the secondary coolant. The steam generator tube integrity is requisite to meeting these functions.

The plant technical specifications in Section 5.5.8, define the regulatory framework for developing and implementing a steam generator program to ensure steam generator tube integrity is maintained. The plant technical specifications require, in part, that the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that steam generator tube integrity is maintained until the next steam generator inspection. Apart from this performance-based requirement, the technical specifications do not specify what specific inspections should be conducted following an OBE.

By letter dated September 27, 2011 (Serial No. 11-520A; Reference 2), the licensee provided a status update that included a description of Steam Generator activities. The licensee also provided information regarding steam generators on October 3, 2011 (Serial No. 11-566; Reference 4), October 10, 2011 (Serial No. 11-566A; Reference 6), and October 28, 2011 (Serial No. 11-566B; Reference 11). According to the licensee's letter dated September 27, 2011, industry guidelines (EPRI Report 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7, Section 3.10) state that forced outage inspections should be performed during plant shutdown subsequent to a seismic occurrence greater than the OBE. The guidelines call for performance of a 20-percent sample inspection of the Unit 1 and Unit 2 steam generator tubes.

To satisfy the guideline 20-percent inspection sample criteria, the licensee implemented a 100-percent eddy current test inspection sample of the Unit 1 steam generator A tubes, constituting a 33-percent sample of the total steam generator tube population for Unit 1, and a 100-percent eddy current test inspection sample of the Unit 2 steam generator A and steam generator C tubes, constituting a 67-percent sample of the total steam generator tube population for Unit 2. These were bobbin coil examinations. The licensee stated that prior to this outage, tube wear at the tube support plates was the only degradation mechanism classified as "existing" in the NAPS Unit 1 steam generator tubing. Several other mechanisms were classified as "potential" mechanisms including tube wear at the anti-vibration bars and tube wear caused by foreign objects. The licensee stated that it was primarily these damage mechanisms that were targeted by this inspection. In addition, while tube denting and dinging are not considered tube degradation mechanisms, the licensee was also interested in whether August 23, 2011, seismic

event had led to new dents and dings. The NRC staff notes that there have been no reported instances of corrosion related degradation affecting any steam generators in the U.S. with alloy 690 thermally treated tubes such as those at NAPS.

The licensee supplemented the bobbin coil examinations with rotating pancake coil inspections at special interest locations. This included 100 percent of the row 1 u-bends (which could not be inspected with the bobbin due to its tight radius), 50 percent of the tubes in the sludge pile region near the top of the tubesheet, and 50 percent of the tubes located within five tubes of the bundle periphery at the top of the tubesheet. The licensee also conducted secondary-side inspections in Unit 1 steam generator A and Unit 2 steam generator A and steam generator C. These included foreign object search and retrieval and visual inspections of steam generator secondary-side internals. The NRC staff notes that the integrity of the secondary-side internals, including the tube support structures, is important to ensuring steam generator tube integrity.

The eddy current examinations at Units 1 and 2 identified no adverse indications as a result of the seismic event. For Unit 1 steam generator A, three tubes were identified with shallow volumetric indications at tube support plates which the licensee attributes to wear. Each of these indications were initially identified during inspections conducted in 2007 and appear not to have grown since that time. The largest of these has a measured through-wall depth of 13 percent. The measured depths are less than the 40-percent plugging limit in the technical specifications. Accordingly, each of the affected tubes remains in service. For Unit 2 steam generator A and steam generator C, no flaw indications were reported.

The licensee reported that two loose parts where identified in the hot-leg channel head of steam generator A of Unit 1. One of these objects was found lodged in a tube in the tubesheet region and was removed. Post-removal, bobbin coil examination over the full tube length and rotating pancake coil examination over the full tubesheet depth confirmed that the object caused no tube degradation. The second object was identified lying on the bottom of the hot-leg channel head bowl and was also removed. A visual inspection of the tubesheet revealed no evidence of tube end or cladding damage. The licensee stated that both objects are of 300 series stainless steel and appear to be from the same part. The licensee stated that the objects appear to be some kind of conduit clip; however, they do not match any parts that are stocked at NAPS.

The licensee conducted two lines of investigation to establish the source of the loose parts. One, the licensee evaluated whether the loose parts could have originated from the reactor vessel internals, including the fuel assemblies, the RCS or a system connected to the RCS (e.g., Safety Injection). This included an extensive review of drawings and parts lists for the reactor internals, low head safety injection pump, and valves in the RCS and SI system as well as a review of potential flow paths from potential sources. No parts were identified that were consistent with the loose parts. Two, the licensee evaluated potential sources external to the RCS, including the manipulator crane (including electrical and pipe clamps), the reactor head O-ring retainer clips, and performed a walkdown of components near the reactor cavity, but nothing that the loose parts could have come from was identified. The licensee also consulted with the vendor who conducted the 10-year inservice inspection in 2009. The vendor confirmed that the foreign material that was found in the S/G does not match any equipment used during the reactor inspection or any equipment used in the rigging of the inspection equipment. Finally, the licensee trended condition reports and alarms from the Vibration and Loose Parts Monitoring System (V&LPMS) to investigate the time frame when the loose parts could have

been introduced into the RCS. This investigation identified several “plausible” loose part indications after the most recent steam generator inspection in 2007 (no steam generator loose parts identified at that time) and 10-year inservice inspection in 2009. The licensee concluded that no definitive source for the loose parts could be identified. The licensee stated that it can be concluded with a reasonable level of confidence that the foreign material entered the RCS from an external source and was, therefore, not generated within the RCS and were not seismically related. The licensee also concluded that the most likely timeframe when such material could have been introduced into the RCS would have been during the 2007 or 2009 refueling outages.

Secondary side inspections were also performed for Unit 1 steam generator A and Unit 2 steam generator A and C. Visual inspections of the J-nozzle interfaces with the internal feedring in each of these steam generators were performed to identify any locations where flow-assisted corrosion (FAC) may have continued to advance. These inspections revealed no discernable change in the degree of FAC since previous inspections in 2007. Ultrasonic testing (UT) thickness measurements were performed at selected locations of the feedring in each of these steam generators for purposes of monitoring FAC-related degradation. The thickness measurements exceeded the minimum full section design requirement of 0.350 inches with the exception of one localized area which measured 0.350 inches. Westinghouse performed a re-analysis of the allowable minimum wall thickness, which considered the localized nature of the thinned wall. The analysis showed the allowable minimum wall thickness for this localized area to be 0.240 inches, which the licensee concludes provides ample margin relative to the projected thickness at the time of the next scheduled inspection.

Additional secondary-side visual inspections included the steam drum internals and upper tube bundle regions. Visual examinations of the blowdown pipe, blowdown pipe supports, non-tube lane tie rods, wrapper and wrapper supports, and tube periphery were performed from the lower hand hole inspection ports above the top of the tubesheet. These examinations revealed no evidence of structural damage, foreign objects, or loose parts.

5.2.2 NRC Staff Evaluation

The NRC staff reviewed the scope and results of the primary-side and secondary-side inspections of the steam generators at NAPS, Units 1 and 2. The licensee inspected three of the six steam generators at Units 1 and 2. The NRC staff concludes this to be an adequate sample based on the sample being representative of all six steam generators and that the inspections performed revealed that the earthquake caused no damage to the steam generator tubing or internals which could impair the safety functionality/operability of the steam generators. All six steam generators at Units 1 and 2 were in similar condition prior to the earthquake, as shown by previous inspections. Tube degradation in all six steam generators prior to the earthquake had been found to be minor, limited to wear at the tube support plate supports affecting a small number of tubes. The steam generators inspected included all three possible steam generator orientations (in terms of the u-bend planes) relative to the spectral ground motions in the X and Y directions. The two minor wear indications found during the current outage in Unit 1 steam generator A date to previous inspections and clearly were not earthquake related. Similarly, the FAC degradation observed in the feedrings of the steam generators inspected is a continuation of previously observed trends, is within acceptable limits, and is not earthquake related.

On the basis of the licensee's systematic, comprehensive investigation of the source of the loose parts found in the Unit 1, steam generator A channel head area, the NRC staff believes it likely, though not certain, that the loose parts are not seismically related and were introduced during a previous maintenance activity. Irrespective of the source of these loose parts, the NRC staff notes that there have been past instances, industry-wide, of loose parts being found in the steam generator hot-leg channel head, including pieces of maintenance related equipment. These occurrences have caused impact type damage to the tube ends protruding below the bottom of the primary face of the tubesheet and which are not pressure boundary. Based on this experience, the possible presence of loose parts in one of the uninspected steam generators would not be expected to cause significant pressure boundary damage prior to the next inspection of these steam generators and, therefore, would not impair safety functionality/operability of the steam generators. Even should hypothetical loose parts in the uninspected steam generators cause damage to the tube-to-tubesheet welds or be lodged in a tube or tubes, the NRC staff concludes the likely consequence would be limited to a small primary-to-secondary leak. Tight limiting condition for operation (LCO) limits on primary-to-secondary leakage in the plant technical specifications would ensure timely plant shutdown before significant impairment of steam generator tube integrity and, thus, before impairment of the safety functionality/operability of the steam generators.

5.2.3 Conclusion

The NRC staff finds that the scope of the primary-side and secondary-side inspections were adequate to confirm that the August 23, 2011, earthquake caused no functional damage to the steam generators such that the resumption of plant operation will not result in undue risk to public health and safety.

5.3 Reactor Vessel Internals

The NRC staff has reviewed the licensee's restart readiness determination information regarding the assessments performed to demonstrate the functionality of the reactor vessel internals (RVIs). The NRC staff concludes that there is reasonable assurance that there was no functional damage to the RVIs as a result of the August 23, 2011, seismic event and therefore, with respect to the RVIs, resumption of plant operation will not result in undue risk to the health and safety of the public. The NRC staff's assessment supporting this conclusion is documented below and is organized to present the technical evaluation of the information submitted by the licensee specific to the RVIs assessment.

5.3.1 Description of Licensee Evaluations/Actions

By letter dated September 17, 2011 (Serial No. 11-520; Reference 1), the licensee submitted a summary report of the seismic event response and its restart readiness determination plan. Enclosure 3 of the September 17, 2011, submittal contained the post-earthquake evaluation of the RVIs. The design-basis functions of the RVIs are described in Section 4.2.2, "Reactor Vessel Internals," of the NAPS UFSAR. The functional capabilities of the RVIs are maintained if the structural integrity of the RVIs is also maintained, and this functionality can be demonstrated by maintaining the dimensions of the RVI components and limiting deformation and deflections. The criteria related to the structural and mechanical design of the RVIs is documented in NAPS UFSAR Section 3.9.3, "Components Not Covered by ASME Code." Enclosure 2 of the

September 17, 2011, submittal described the post-earthquake inspections of the NAPS SSCs. The NAPS inspection methodology utilized EPRI-NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake." The licensee found that the inspections "…did not identify any significant physical or functional damage to safety-related SSCs that would render them incapable of performing their design functions."

To ensure that the functionality and the structural integrity of the RVI components is maintained, the licensee performed a margin assessment for the NAPS Unit 1 and Unit 2 RVIs in addition to conducting inspections of the RVI components in NAPS Unit 2. The licensee determined that inspection of RVI components in NAPS Unit 2 would be representative of NAPS Unit 1 based on the following:

1. The August 23, 2011, earthquake did not produce any significant or functional damage to the RVI components in NAPS Unit 2 and, therefore, it is likely to expect similar inspection results for the RVI components in NAPS Unit 1.

2. Because of the differences in the local flow conditions between NAPS Unit 1 and Unit 2, baffle bolt failure and baffle jetting is more likely to occur in NAPS Unit 2. Since no baffle bolt failures were observed during the recent inspections of NAPS Unit 2, the expectations are that the structural integrity and the functionality of the baffle bolts in NAPS Unit 1 should also be maintained.

3. Evaluation of the NAPS Unit 1 and Unit 2 RVI design margins was performed using the existing design analyses, as documented in the licensee's submittals (Serial Nos. 11-520 (Reference 1), 11-544B (Reference 9), and 11-566 (Reference 4), and provides reasonable assurance that the RVI components in both Units would maintain their continued functionality during the August 23, 2011, seismic event.

5.3.2 NRC Staff Evaluation of RVI Margin Assessment

The NRC staff reviewed the information provided in the licensee's September 17, 2011, restart readiness submittal and supplements dated October 3, 2011 (two letters, Serial Nos. 11-566 and 11-544A; References 4 and 5, respectively) and October 28, 2011 (Serial No. 11-566B; Reference 11), pertinent to the NRC staff's assessment of the seismic loads induced in the RVIs and the ensuing assessment of the structural functionality of the RVIs.

As indicated in its September 17, 2011, submittal, the licensee performed a margin assessment for several key RVI load points where the RVIs interface with the reactor pressure vessel. The RVI interface load points exist between the reactor pressure vessel and the core barrel, and between the fuel and core plates. Additionally, the licensee indicated in its October 3, 2011, submittal that a preliminary assessment has indicated that the loads imposed by the August 23, 2011, seismic event on the lower support forging (lower support plate and lower core plate), upper core plate and guide tubes are acceptable. The NRC staff requested the licensee to provide a technical justification demonstrating that the analytical evaluations of the key load points provide sufficient bases to state that the remainder of the RVIs, which were not included in the margin assessment, did not also suffer any deformation or change in geometry as a result of the August 23, 2011, seismic event at NAPS. In its October 28, 2011, RAI response, the

licensee stated that evaluating the key load points at which the RVIs may potentially impact the reactor pressure vessel provides a sufficient means to characterize the behavior of the other RVIs which do not impact the reactor pressure vessel. The NRC staff considers the licensee's response acceptable, given that it is reasonable to assume that if RVIs which impact the reactor pressure vessel, which are limiting components, do not suffer deformation, the same conclusion can be extrapolated to RVIs which do not directly impact the reactor pressure vessel.

The licensee stated that the margin assessments consisted of comparing the loads experienced at aforementioned RVI interface loads points, resulting from the application of the seismic-only loads, to the load limits corresponding to the upset loading condition. The upset loading condition is defined in the NAPS UFSAR. The load limits associated with the upset condition require that the stresses induced in a component or structure be maintained below a level where deformation is possible, which ensures that a component maintains its elastic behavior and does not deform permanently. As such, by satisfying the load limits for which no deformation is permitted, the licensee stated that the analytical results provide assurance that no deformation or alteration in geometry would have occurred as a result of the August 23, 2011, seismic loads imparted on the RVIs.

In its October 28, 2011, response to NRC staff RAIs related to the loading combinations used in the margin assessments, the licensee stated that: 1) the "seismic only" margin assessment included loads resulting from a seismic event and all other loads associated with normal operation (i.e., deadweight plus thermal and pressure loads), and 2) that the seismic loads used in the margin assessment for most of the interface load points were developed using the OBE and DBE loads contained within the current analyses of record for the RVIs, depending on which spectra provides the more limiting loading condition on the component (lower damping values used in conjunction with OBE loads may result in higher loads using the OBE spectra than loads resulting from application of the DBE spectra). The licensee's margin assessment performed for the lower radial keys was based on the time histories developed from the August 23, 2011, seismic event at NAPS.

Based on the fact that the OBE and DBE spectra were exceeded during the August 23, 2011, seismic event, the NRC staff issued an RAI to the licensee requesting justification for the use of the OBE and DBE loads in performing its margin assessment. In the licensee's October 28, 2011, response, the licensee stated that the results of the margin assessment demonstrate that the use of the current OBE and DBE spectra provide an adequate means of demonstrating that the loads resulting from the August 23, 2011, seismic event would not have created loads which would have exceeded the load limits presented in Table 1 of the licensee's October 28, 2011, RAI response. However, for the lower radial keys, the licensee indicated that the margin assessment for the current OBE and DBE loads was supplemented by performing a detailed evaluation of these loads points using the loads developed from the August 23, 2011, time histories. The results of this calculation were presented in the licensee's October 28, 2011, RAI response and the licensee demonstrated that the stresses in these components resulting from the actual time histories remain below the applicable stress limits corresponding to the upset condition.

The NRC staff considers the licensee's justification acceptable, based primarily on the results of the margin assessment, discussed below, which show that the amount of margin maintained between key load points and the upset limits is such that the use of the loads developed from

the August 23, 2011, seismic event would not be expected to approach the load limits corresponding to the upset condition for each interface location where the current OBE and DBE loads were applied.

The NRC staff reviewed the results of the licensee's margin assessments presented in Table 1 of the licensee's October 28, 2011, submittal. Table 1 in this submittal provides the reactor pressure vessel-RVI impact loads calculated by the licensee corresponding to a combination of the normal operating loads and those loads associated with the OBE and DBE spectra. The results show that the interface loads, excluding the lower radial key interface loads, maintain a margin of at least 55 percent when the calculated loads (OBE or DBE-based) are compared against the applicable upset load limit. Additionally, the results also show that the differences between the loads calculated for the OBE and DBE cases are relatively small when compared to the load limit associated with each component. As previously stated, while the licensee did not incorporate the August 23, 2011, seismic loads into its margin assessment for a portion of the key load points evaluated, the NRC staff notes that the amount of margin present in its results demonstrates that there is sufficient basis to conclude that the upset load limits would remain satisfied under the loading conditions imposed on the internals as a result of the August 23, 2011, seismic event. This conclusion is further supported by comparing the incremental differences in interface loads between the OBE and DBE loading conditions in Table 1.

For the lower radial key interface loads, the licensee utilized the time histories corresponding to the August 23, 2011, seismic event and demonstrated that adequate margin (approximately 16 percent) exists between the stresses induced at this load point and the upset stress limit applicable to yielding. By letter dated October 31, 2011, the licensee provided additional clarification regarding its results of the stress analysis performed for the lower radial keys. The licensee stated that the acceptance criteria associated with the elastic stress limits for the lower radial key do not require the summation of the maximum individually calculated primary membrane and primary bending stresses resulting from the stress analysis of the entire component. The NRC staff considers the licensee's assessment acceptable and consistent with the design requirements of the ASME Code Subsection NG, "Core Support Structures." The NRC staff notes that the ASME Code provisions governing the design of these components do not require the combination of the individual maximum primary membrane and maximum primary bending stresses when these stresses are compared against their applicable stress limits, given that the maximum values of these stresses may not be located at the same location on a component. This is illustrated in Figure 1 of the licensee's October 31, 2011 (Serial No. 11-566E; Reference 17).

Therefore, based on the fact that the licensee has demonstrated that adequate margin exists between the no-deformation load and stress limits and the loads and stresses induced in the RVIs which were evaluated, the NRC staff finds that the licensee has demonstrated that no functional damage occurred to the RVIs as a result of the August 23, 2011, seismic event at NAPS and thus no functional damage has occurred. This conclusion is based on the following considerations: 1) the acceptance criteria used by the licensee are more stringent than those used to structurally qualify the RVIs against loads due to a DBE, in that the limits used in the licensee's margin assessment do not permit deformation and, 2) by satisfying the aforementioned acceptance criteria, the licensee has shown that deformation and subsequent geometrical alterations of the NAPS Unit 1 and Unit 2 RVIs would not be expected as a result of

the August 23, 2011, seismic event at NAPS, thus satisfying the criteria for functionality as documented in the NAPS UFSAR, which states that the deformation of certain critical reactor internals must be kept sufficiently small to permit core cooling.

The NRC staff also notes that, as stated in the NAPS UFSAR Section 3.9, the structural qualification of the RVIs requires consideration of load combinations whereby a LOCA and DBE are assumed to occur simultaneously to assess the structural integrity of the RVIs under these design-basis conditions. When the loads resulting from the LOCA are compared to those resulting from the August 23, 2011, earthquake, the earthquake loads are small, suggesting that the RVIs are governed by the LOCA; this is consistent with the licensee's margin assessment, which shows that the loads imposed on the RVIs resulting from a DBE do not result in exceedance of load limits which are more stringent than those required by the design-basis requirements for the RVIs (i.e., elastic load limits). Additionally, for the lower radial keys, the licensee was able to demonstrate that adequate margin exists between the calculated stresses and the upset condition stress limits at these points when subjected to the actual loads resulting from the August 23, 2011, seismic event, demonstrating that no deformation would be expected. These conclusions are further substantiated by the inspections performed by the licensee on the RVIs, which are discussed below, and revealed no anomalies for the RVIs.

5.3.3 NRC Staff Evaluation of RVI Inspection Efforts

The NRC staff reviewed the summary of inspections performed on the RVI components. In evaluating the licensee's inspection efforts related to the structural functionality of the RVIs, the NRC staff considered the information provided in the licensee's October 10, 2011, submittal. The licensee's inspections of the RVIs were focused on 1) general overview inspections of the RVIs to determine whether any observable misalignment or damage was present in the RVIs as a result of the August 23, 2011, seismic event, and 2) additional inspections on RVIs which are sensitive with respect to the loads induced on these RVIs due to a seismic event. The licensee stated that the inspections were focused on determining whether damage resulting from the seismic event was evident in any of the RVIs chosen as part of the inspection scope. As indicated in its October 10, 2011, submittal, the licensee indicated that the inspections focused on identifying damage consistent with brief, strong motion cyclic loading (i.e., seismic loads), such as visible distortion, bending and tack weld disruption or failure. The NRC staff considers this assessment acceptable, given that any damage associated with the short, dynamic loadings induced by a seismic event would be expected to be visible and contrastable with damage resulting from other mechanisms, such as high-cycle fatigue.

In the licensee's October 10, 2011, submittal, it stated that RVI components selected for additional inspection were chosen based on their sensitivity to imposed seismic loading using the following criteria: component flexibility, components spanning between and connecting flexible structures, anchorage of larger components, and interfacing components subject to large seismic load transfers. The NRC staff notes that no specific guidance is provided in EPRI NP-6695 relative to the selection of RVIs for additional inspection efforts following a seismic event. However, the NRC staff considers the licensee's criteria for identifying RVIs for additional inspection acceptable, given that the licensee utilized criteria which ensure that those RVIs most susceptible to damage from a seismic event (i.e., flexible components, anchorages and interfacing components) were included within the scope of the licensee's inspection efforts. Further, in accordance with EPRI NP-6695 the NRC staff notes that inspection of the RVIs is not

called for following a seismic event classified as a Level 0 intensity event, such as the August 23, 2011, seismic event at NAPS. Therefore, the NRC staff considers the licensee's inspection efforts related to the RVIs provides to be an additional level of conservatism in concluding that the structural functionality of the RVIs was not compromised by the August 23, 2011, seismic event.

The components which were subject to the aforementioned additional inspections by the licensee are tabulated on pages 17 and 18 of the licensee's October 10, 2011, submittal. This table identifies the RVI components inspected and the bases for their selection, in accordance with the criteria above, and also identifies the potential failure mechanisms to which a particular RVI may be subject to experiencing. The licensee included many lock welds within its scope of additional inspections of the RVIs, as indicated in the aforementioned table. Given that the licensee has indicated that most of these welds are essentially tack welds (i.e., small welds), it would be expected that these welds would be sufficient indicators of damage to the bolts on which they are applied, given that the stresses induced in these welds resulting from the seismic event would be much greater than the stresses induced in the underlying bolting. The licensee indicated that foreign object searches performed on the lower core plate and in the lower bowl of the RPV did not identify any foreign objects related to the RVIs. The results of the licensee's inspection efforts, including the general overview inspections and additional inspections, revealed no indications of adverse conditions of any of the RVIs.

The NRC staff's assessment of the licensee's inspection results concludes that the inspections provide additional assurance that the structural functionality of the RVIs was not affected by the August 23, 2011, seismic event at NAPS. This assurance is based on the licensee's inspection results, which found no adverse conditions in the NAPS Unit 2 RVIs and no foreign objects resulting from damage to the RVIs, which suggests that no structural damage was incurred by the RVIs as a result of the seismic event. The NRC staff considers the licensee's inspection results to be a sufficient indicator that the licensee's margin assessment, described above, correctly concluded that no deformation of the RVIs was caused by the August 23, 2011, seismic event at NAPS, which supports the licensee's conclusion that no functional damage occurred to the RVIs. The NRC staff's assessment of the inspection of the RVIs, with respect to the nuclear and thermal-hydraulic functionality of the RVIs, is included in the section on nuclear fuel performance in this safety evaluation.

The licensee identified specific RVI components of NAPS Unit 2 to be inspected in order to assess potential damage caused by the seismic event, and determined that the inspection results of NAPS Unit 2 would be representative of findings for NAPS Unit 1 based on the following: (1) design features of the RVI components in the both NAPS units are very similar, with the exception of design features related to local flow conditions. NAPS Unit 1 was converted to up flow in the baffle-former region, while NAPS, Unit 2 maintained the original down-flow configuration, and (2) original down-flow conditions in NAPS, Unit 2 increase the susceptibility of the baffle-former assembly, including the baffle-former bolts, to damage and abnormal conditions such as baffle jetting. These conditions in NAPS, Unit 2 would bound Unit 1 with respect to the functionality of the baffle-former assembly, including the baffle bolts. Therefore, the licensee determined that it is appropriate to inspect the RVI components in Unit 2, and apply the inspection results to the RVI components in Unit 1.

With respect to the metallurgical performance of the NAPS RVIs, the NRC staff reviewed the licensee's technical basis for applying the inspection results of the RVI components in NAPS Unit 2 to the RVI components in Unit 1. Based on a review of NAPS UFSAR Section 4.2.2.2, the NRC staff concludes that the same types of materials were used in the RVI components of Units 1 and 2. The impact of the seismic event on the material performance of the RVI components in NAPS Unit 1 and 2 would be similar. A seismic event could potentially be expected to cause damage to RVI components with severe preexisting degradation due to intergranular stress-corrosion cracking (IGSCC) or irradiation-assisted stress-corrosion cracking (IASCC), and/or reduced fracture toughness due to irradiation embrittlement. Such damage would be manifested as gross cracking or deformation that would be readily detectable by a visual examination. Small cracks would not be expected to experience any growth due to the seismic event. As indicated above, no visible damage to the RVI components in NAPS Unit 2 was detected. Therefore, the NRC staff concludes that the RVI components of NAPS Unit 2 experienced no functional damage. In addition, the NRC staff concludes that the identical types of RVI component materials in both units would react similarly and since no damage to the RVI components was visible in Unit 2, that the RVI components in Unit 1 would be adequately represented by the inspection results of Unit 2 and, similarly, would retain functionality.

The NRC staff notes that the inspections performed by the licensee on the NAPS Unit 2 RVIs are similar to those inspections outlined in the EPRI Materials Reliability Program (MRP) 227, "Pressurized Water Reactor Internals Inspections and Evaluation Guidelines," December 2008 (Reference 32). These guidelines have been approved for use by the NRC staff and have been adopted for use by a number of PWR facilities. While MRP-227 is used primarily to address issues relating to RVI material degradation due to aging effects, the NRC staff considered the inspection guidelines documented in MRP-227 as part of its overall assessment of the impact of the August 23, 2011, seismic event on the structural integrity of the NAPS RVIs.

Inspections performed by the licensee on the RVI components in NAPS Unit 2 are similar to those specified in the MRP-227, with the following exceptions: 1) inspections were not performed on some of the "Primary" components addressed in MRP-227 (e.g., upper core barrel flange weld, baffle-edge bolts, baffle-former assembly, thermal shield flexures and internal hold-down springs), and 2) the inspection methodology is not always consistent with MRP-227, for example ultrasonic testing (UT) is recommended for baffle-former bolts per MRP-227, whereas the licensee performed visual testing (VT-3) inspections which may not adequately identify the extent of cracking. The licensee provided a basis for performing VT-3 in lieu of UT on the baffle bolts. The licensee's contention is that previous experience indicates that cracking due to IASCC in the baffle-former bolts was identified by VT-3 examination of Type 347 baffle-former bolts. Additionally, VT-3 examination is adequate in identifying any gross damage that would normally occur due to an earthquake. Therefore, the licensee concluded that a VT-3 examination is adequate for detecting any damage in the baffle-former bolts due to the August 23, 2011, seismic event at NAPS Units 1 and 2.

In the Enclosure to the letter dated October 18, 2011 (Serial No. 11-566B; Reference 9), the licensee indicated that the scope of the inspections of the RVI components in NAPS Unit 2, in the context of the August 23, 2011, seismic event, is different from the inspections recommended by the MRP-227 report. The guidelines in MRP-227 require inspections of the RVI components that are highly susceptible to the long-term effects of aging due to any active degradation mechanism. The licensee determined that it was not necessary to inspect certain

RVI components listed in the NRC staff's RAI because they are not seismically sensitive and other components that are sensitive to seismic loading and deemed the leading indicators of damage were already inspected and no damage was found. The upper-core barrel-flange weld was not inspected because the leading indicators were control rod guide tubes, and their welds and bolting. Baffle-edge bolts were not inspected because the leading indicators were the baffle-former bolts, which were inspected. The licensee conducted inspections of the baffle assembly, which entailed inspections of baffle bolts and inspections of the edge gap between the baffle plates. According to the licensee, no damage was found, and therefore, the licensee concluded that these inspections are applicable to the baffle-former assembly. The thermal shield flexures were not inspected because previous examinations of the thermal shield flexures in NAPS Unit 1 (2009) and Unit 2 (2010) showed no damage. Because the flexures do not provide any core support function, they are considered unlikely to experience any seismic damage. Hold-down springs are not considered to be seismically sensitive; hence, no inspections were performed.

The NRC staff reviewed the licensee's response with respect to the inspections that were performed on the RVI components in NAPS Unit 2 and finds that the licensee's justifications for not inspecting the aforementioned components in Unit 2, is acceptable. The NRC staff agrees that the August 23, 2011, seismic event would not be expected to have any impact on the long-term aging effects due to an active aging degradation mechanism, such as stress corrosion cracking. Although, the aforementioned RVI components are considered as some of the most susceptible RVI components to damage due to active long-term aging mechanisms, they are not deemed to be the leading indicators of damage due to a seismic event. Since the seismically sensitive leading indicators that correspond to the aforementioned RVI components showed no damage, the NRC staff concludes that the RVI components described above were not affected by the August 23, 2011, seismic event. Therefore, the NRC staff concluded that no functional damage occurred to the RVI components.

With respect to the NRC staff's RAI associated with the inspections of the baffle bolts, the licensee, in the enclosure to the letter dated October 18, 2011 (Serial No. 11-566B), stated that unlike Type 347 stainless steel baffle-former bolts, the Type 316 stainless steel cold-worked baffle-former bolts that were installed in NAPS Units 1 and 2 are less susceptible to IASCC. The licensee further stated that thus far, no cracking has been observed in cold-worked Type 316 stainless baffle-former bolts in the PWR fleet, and that no damage was noted in the baffle-former bolts at NAPS Unit 2. The licensee also used a plant-specific bolt pattern analysis from WCAP-15042, "Determination of Acceptable Baffle-Barrel-Bolting for Three-Loop Westinghouse 17 X 17 Down Flow and Converted Up Flow Domestic Plants," to determine the minimum number of bolts that are required to maintain the functionality of the baffle-former assembly. More bolts are needed in Unit 2 because of the down-flow design; conversely, the converted up flow design in Unit 1 requires a lower number of bolts. In down-flow plants, such as Unit 2, the pressure drop across the baffle plates is sufficient to force RCS water through an existing gap between the edges of adjacent baffle plates, sometimes causing flow-induced vibration of fuel rods close to the baffle plate gaps. Changing the design configuration from down-flow to up-flow reduces the pressure drop across the baffle plates, thus eliminating potential fuel rod degradation. Since no damage was found during the inspection of the baffle-former assembly in Unit 2 (which is more bounding than Unit 1), the licensee determined that a very large margin for ensuring the safety function of the baffle-former assembly, including the baffle-former bolts, exists during the normal and design-basis loading in NAPS Unit 1.

Therefore, based on its review and evaluation of the discussion above, the NRC staff concluded that the licensee demonstrated that no functional damage had occurred to the baffle-former bolts in Units 1 and 2.

The NRC staff reviewed the licensee's disposition and determined that any gross damage that could usually occur due to a seismic event could be identified by using VT-3 technique. Since NAPS Units 1 and 2 have Type 316 stainless steel cold-worked baffle-former bolts, it is unlikely that these baffle bolts have experienced IASCC. The justifiable reason for substituting VT-3 for UT examinations is that Type 316 stainless steel cold worked baffle-former bolts are less susceptible to IASCC than Type 347 stainless steel baffle-former bolts, and thus far, the industry operating experience supports this observation. In plants with more susceptible baffle-former bolt materials, the percentages of failed bolts were very small in comparison to the large structural margins, with respect to the number of bolts. While VT-3 examination cannot detect partially cracked bolts, and may not detect isolated failed bolts which could be retained by the bolt locking devices, widespread bolt failure would be expected to result in gaps between baffle plates. These gaps would be readily detectable via VT-3 visual examinations. Since no gaps were observed, it can be concluded that no widespread baffle-former bolt failures have occurred. Based on the absence of visual evidence of bolt failures, plus the relatively low susceptibility of the NAPS baffle-former bolt materials to IASCC, the NRC staff finds that the licensee's response with respect to the implementation of VT-3 in lieu of UT examinations of Type 316 stainless steel cold worked baffle bolts at Unit 2 is acceptable.

5.3.4 Conclusion

Based on the evaluation of the effects of the August 23, 2011, seismic event on the RVI components, the NRC staff concludes that no functional damage has occurred to the RVIs such that the resumption of plant operation will not result in undue risk to the health and safety of the public. The NRC staff considered the magnitude and the duration of the seismic loading, and its impact on the structural integrity and the functionality of the RVI components. The technical bases for the NRC staff's conclusion are described below.

The NRC staff concludes that there is reasonable assurance that no functional damage occurred to the RVIs as a result of the August 23, 2011, seismic event at NAPS based on the following considerations: 1) the results of the licensee's structural margin assessment of the NAPS Unit 1 and Unit 2 RVIs demonstrated that adequate margin exists between the loads and stresses induced in the RVIs, as a result of imposed loading due to a seismic event, and the upset stress and load limits associated with the RVIs, which demonstrates that no deformation of the RVIs would be expected as a result of the August 23, 2011, seismic event, thus satisfying the RVI structural functionality requirements stipulated in the NAPS UFSAR; and 2) the inspections performed by the licensee for the NAPS Unit 2 RVIs, which are the most structurally limiting RVIs when compared to the NAPS Unit 1 RVIs, provided visual confirmation that no functional damage has been sustained by the RVIs which were inspected, thus providing validation of the analytical evaluations (i.e., margin assessments) performed by the licensee.

The NRC staff further notes that this conclusion is consistent with the design bases of the RVIs, which requires the RVIs to remain functional when loads due to a seismic event (i.e., SSE) and a LOCA are imposed simultaneously. As stated in the NAPS FSAR, the loads due to a seismic event are small compared to those loads imposed on the RVIs by a LOCA. Given that the RVIs

were subjected only to seismic loads during the August 23, 2011, seismic event, the NRC staff concludes that this provides additional reasonable assurance that no functional damage was sustained by the RVIs as a result of the seismic event. Further, the NRC staff's conclusion is consistent with the guidance of EPRI NP-6695, which does not require the inspection of the RVIs following a Level 0-intensity seismic event, due to the fact that the damage associated with such a seismic event is minimal and structures designed to accommodate the loads imposed by a seismic event, such as the RVIs, are not expected to be affected.

5.4 Pumps and Valves Inservice Test Program

5.4.1 Description of the Licensee Evaluation/Actions

The licensee stated in its submittal dated September 17, 2011, Enclosure 2, that, the initial walkdown and "visual inspections were performed by engineering personnel immediately following the August 23, 2011, earthquake, and the subsequent aftershocks up to August 26, 2011. The damage discovered during these inspections did not identify any significant physical or functional damage to safety-related SSCs and only limited damage to non-safety-related, non-seismically designed SSCs (e.g., generator step-up transformer bushings). Condition Reports (CRs) were submitted for the identified discrepancies. The results of these and additional focused inspections supported an EPRI Damage Intensity of 0, which is defined in Table 2-1 in EPRI NP-6695."

The licensee further stated that, "to confirm the EPRI Damage Intensity, conservative measures were taken to perform comprehensive and methodical expanded inspections of the plant to further assess the impact of the earthquake on plant safe shutdown SSCs. The expanded inspections were performed as part of the post-shutdown actions defined in EPRI NP-6695. Technical Specification Surveillance tests will also be completed prior to Unit 1 and 2 startups to further demonstrate that SSCs can perform their design functions."

Section 5 of EPRI NP-6695 provides guidelines for post-shutdown inspections and tests of nuclear plant equipment and structures required for operation prior to restart of a nuclear plant which has been shut down due to an earthquake that exceeds the OBE. Section 5.3.2.1 states that, "horizontal and vertical pumps should all be inspected post-earthquake and valves should be inspected on a sampled basis." The licensee stated in its letter dated September 17, 2011, that, "the Surveillance Periodic Tests as defined in the Technical Specifications for Units 1 and 2 will be completed prior to unit start-up as guided by EPRI NP-6695, Appendix B, 'Typical Surveillance Tests for PWRs.'"

In a response to RAIs from the NRC staff, the licensee provided further information, in letters dated October 20, 2011, and October 28, 2011, about the inspection and testing of pumps and valves. To evaluate the effects of the August 23, 2011, earthquake on the safety-related pump and valve components of NAPS Units 1 and 2, the licensee performed walkdown inspections of all safety-related pumps and valves, as part of the inspections of the various nuclear power plant systems. The inspections were focused on earthquake damage to the anchorage/support and pipe nozzle portions of the safety-related pumps and valves. No damage was identified.

For the safety-related pumps in the inservice testing (IST) program (including the component cooling water pumps), the licensee tested each pump successfully in accordance with the

ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code) test requirements. The exceptions to the ASME OM Code testing included the Unit 1 inside recirculation spray (IRS) pumps and the auxiliary feedwater (AFW) pumps. The licensee stated that the steam-driven AFW pumps for both units will be tested during start-up activities, when a steam supply is available. The Unit 1 IRS pumps will not be tested because testing of these pumps requires installing a temporary dike around the recirculation spray sump, blanking the suction headers near the sump wall, removing the test inlet covers from the strainer suction header in the sump, and filling the dike with water. The licensee evaluated the operational readiness of the Unit 1 IRS pumps based on the detailed inspections that showed no degradation, a similar orientation within containment as the Unit 2 IRS pumps, the location of the pumps in the basement of the containment, and the successful inservice testing of the Unit 2 IRS pumps.

For the safety-related valves in the IST program, the licensee performed stroke-time testing for the valves in both Units 1 and 2 (including steam generator blowdown containment isolation valves, 1-BD-TV-100A, 100C, and 100E, and 2-BD-TV-200A, 200C, and 200E) and compared the results with pre-earthquake testing data. The licensee also performed functional testing that verified that the valves stroked to the required positions (including check valves) and provided the necessary flow, in the required time. The licensee noted that the results did not indicate any earthquake-related degradation and that the valves were acceptable to perform their designated safety functions.

As provided in licensee's letter dated October 28, 2011, the following valves in the IST Program were stroke time and functionally tested in Unit 1: all 110 motor-operated valves (MOVs), except for five valves that will be tested during start-up; all 145 air-operated valves (AOVs)/solenoid-operated valves (SOVs); and 90 of the approximately 180 check valves. Additionally, approximately 25 manual valves were exercised, except for the valve for the steam supply to turbine for AFW pump (1-MS-18/57/95) that will be tested during start-up. No earthquake-related damage was revealed during the Unit 1 valve inspections and all tested valves passed their stroke time and functional tests. The following valves in Unit 1 will not be functionally tested: all pressure relief valves, approximately 90 of the 180 check valves, and a manual valve for the charging pump cross-tie (1-CH-550, typically performed when the charging system is removed from service).

The following valves in the IST program were stroke time and functionally tested in Unit 2: all 110 MOVs, except for one valve that will be tested during start-up; all 145 AOVs/SOVs, except for 24 valves that will be tested upon start-up; five of the 15 main steam safety valves; one of the three pressurizer safety valves; 28 of the approximately 40 relief valves; and 125 of the 180 check valves. Additionally, 20 manual valves were exercised, except for the valve for the steam supply to turbine for AFW pump (2-MS-18/57/95) that will be tested upon start-up. No earthquake-related damage was observed and all tested valves passed their stroke time and functional tests except for one relief valve. The 1A RHR pump suction header relief valve lifted early at 450 pounds per square inch gauge (psig), which was outside of the acceptable range of 456-485 psig. The licensee stated that the valve was adjusted to the acceptable range and no additional testing was performed, because all of the other valves in the group were tested. The following valves will not be functionally tested in Unit 2: 10 of the 15 main steam safety valves, two of the three pressurizer safety valves, approximately 12 of the 40 relief valves, and 55 of the 180 check valves.

Additionally, three containment isolation valves in Unit 1 did not pass their stroke time tests and these failures were documented in the licensee's letter, dated October 3, 2011. The licensee stated that one failure was caused by an incorrectly adjusted limit switch, resulting in a stroke time slightly greater than the IST program acceptance criteria, but within the containment isolation design requirements. The other two failures were caused by unintended consequences of packing adjustments and the fact that valve closure is normally assisted by steam flow, but no steam flow occurred during testing. The valves' closure time did meet the required accident analysis speed. The licensee repacked the valves and acceptable stroke time results were obtained. None of the stroke time failures were earthquake related nor indicated any functional damage. Additionally, in Unit 1, one main control room air condition service water seal water supply isolation valve, 1-HV-SOV-1200A, indicated a negative trend in stroke time. This stroke time for this valve was within the surveillance procedure allowable range, and the licensee is tracking the valve's performance through the corrective action process.

The licensee also provided additional information on the Units 1 and 2 pressure relief valves in its letter dated September 27, 2011. These pressure relief valves provided overpressure protection for plant equipment, during the trip response, on August 23, 2011. The licensee stated that these power operated relief valves (PORVs), on each unit, operated as designed, maintaining system pressure within operating limits. Additionally, the first point feedwater heaters were isolated and the shell-side relief valves maintained pressure by cycling as the heaters cooled.

During the Unit 2 refueling outage, which commenced following the earthquake, the licenseestated that approximately 90 relief valves were scheduled for preventive maintenance testingand rebuilds. These valves constitute a representative sample of the entire station (e.g., critical relief valves are tested a minimum of every five years and a portion of the valves in each system are tested during a given refueling outage). Additionally, the licensee sent one pressurizer safety valve (2-RC-SV-2551C) and the five MSSVs from the Unit 2 "B" steam generator offsite for as-found testing. The testing results showed that the five MSSVs and the pressurizer safety valve lifted within the as-found tolerance.

The licensee noted in its letter dated October 28, 2011, that all pressure relief valves were examined during walkdowns and visually inspected as part of the seismic response effort and no damage was noted. Relief valve testing results were consistent with previous outage results, no adverse trends in the test results were identified, and no failures were attributed to seismic damage. The licensee also noted in its letter dated September 27, 2011, that safety valves for high pressure systems, such as the RCS and main steam system, were designed to withstand the forces of an earthquake in combination with the load applied to the valves when relieving pressure. Typically, the pressure relief loading exceeds the loading from the seismic event, and therefore, the valves that were not called upon to actuate during the event were subjected to forces below their design limit.

5.4.2 NRC Staff Evaluation

The licensee's IST program provides a systematic approach to assess the operational readiness of pumps and valves at NAPS Units 1 and 2, that perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown

condition, or in mitigating the consequences of an accident. After the earthquake on August 23, 2011, the NRC staff was concerned with the effect of the earthquake on safety-related components, including pumps and valves. On October 3, 2011, an NRC AIT completed an inspection of NAPS Units 1 and 2. No damage of any significance was observed at the plant during this inspection. Results of this inspection are documented in an inspection report dated October 31, 2011 (Reference 30).

A special safety inspection was conducted by the NRC's Post-Earthquake Restart Readiness Review team, consisting of NRC staff from Region II. This inspection included a post-earthquake walkdown inspection of pumps and valves. No pump or valve damage that could be attributed to the August 23, 2011, earthquake was identified during the walkdowns or detailed visual inspections, performed by the team, at NAPS Unit 1 and 2. This confirmed the findings made from comparable visual inspections conducted by the licensee.

In addition to above, the licensee performed the following visual examinations and testing of pumps and valves:

For the safety-related pumps in NAPS Units 1 and 2 IST programs, all except the AFW pumps and the Unit 1 IRS pumps, were successfully tested according to the IST requirements. The turbine-driven AFW (TDAFW) pumps will be tested during startup when a steam supply is available. Delaying the testing of the AFW pumps until steam is available is acceptable to the NRC staff and operability of the AFW pumps is governed by the Technical Specifications. The Unit 1 IRS pumps were not tested because the testing requires the removal and modification of equipment inside containment and the construction of a dike for the pump water supply. The NRC staff determined that not testing the Unit 1 IRS pumps was acceptable based on the following:

- the Unit 2 pumps were tested and passed the IST criteria,
- the Unit 2 pumps are identical to the Unit 1 pumps,
- there was no seal leakage detected on any of the Unit 1 pumps, and
- the Unit 1 pumps are located at the same elevation location in containment as the Unit 2 pumps.

Additionally, the licensee inspected pumps in the IST program for earthquake damage, focusing on anchorage/support and pipe nozzle conditions, and identified no damage. Based on the licensee's testing, inspections, and evaluations of all safety-related pumps in both units, including the Unit 1 IRS pumps, the NRC staff determined that the IST program pumps at NAPS Units 1 and 2 are operationally ready because they have met the IST requirements.

For the valves in NAPS Units 1 and 2, no earthquake-related damage was observed. For the three valves that did not pass the stroke time tests and the one relief valve that lifted early, the failures were not linked to the August 23, 2011, earthquake. Repairs were made to these valves and the valves successfully passed the IST tests. The NRC staff finds that these actions were acceptable and determined that the three successful stroke time tests and the one successful pressure test demonstrated component operational readiness for these valves. For

the valve that contained a negative stroke time trend, the licensee stated that the performance of the valve will be monitored and the issue was included in the corrective action program. The NRC staff finds that this action was acceptable because the valve will be more closely monitored in the future and the condition was not related to the August 23, 2011, earthquake.

The licensee noted that during the Unit 2 refueling outage, approximately 90 pressure relief valves were scheduled for preventive maintenance testing and rebuild work. These valves constitute a representative sample of the relief valves at the entire station. Additionally, the licensee sent one pressurizer safety valve (2-RC-SV-2551C) and the five main steam safety valves (MSSVs) from the Unit 2 "B" steam generator offsite, for as-found testing. The testing results showed that the five MSSVs and the pressurizer safety valve lifted within the as-found tolerance. The licensee noted that all of the pressure relief valves, in both units, were visually inspected during walkdowns, as part of the seismic response effort for both Units and no damage was noted.

The licensee does not plan to perform any relief valve testing for the Unit 1 pressure relief valves in its IST program. The NRC staff finds this absence of testing of the Unit 1 pressure relief valves to be acceptable because the pressure relief valves are of very similar design and function between Units 1 and 2. The licensee noted that test results from the Unit 2 relief valves were consistent with previous outage results, no adverse trends in the test results were identified, and no failures were attributed to seismic damage. Additionally, the Unit 1 relief valves operated properly post-earthquake to allow for proper unit shutdown, demonstrating their ability to withstand the combined earthquake stresses and system pressures without any adverse effects. The Unit 2 safety relief valves demonstrated no earthquake-related degradation through testing. Due to similarities in system and component design, the NRC staff concludes that the Unit 1 and Unit 2 safety relief valves will perform their safety-related functions.

The licensee noted that approximately 90 of the 180 check valves in Unit 1 and 55 of the 180 check valves in Unit 2 will not be tested. The NRC staff finds this to be acceptable because the licensee tested more than half of the check valves in each unit; each IST test was successful; and no damage was identified to any check valves, in either unit. Additionally, the check valves are generally based on a simple design, with few delicate components that could be damaged by the vibrations due to an earthquake.

The licensee noted that one manual valve in Unit 1, the charging pump cross-tie valve, 1-CH-550, would not be exercised prior to unit restart. All Unit 2 manual valves have been or will be exercised prior to restart of the unit. The NRC staff finds this acceptable because all of the Unit 2 valves will be tested prior to restart and the unexercised manual valve in Unit 1 had no damage upon inspection and 24 of the 25 IST program manual valves were successfully exercised in this unit.

5.4.3 Conclusion

Detailed walkdown inspections conducted by the licensee did not identify any pump or valve damage that could be attributed to the earthquake that occurred on August 23, 2011. Testing demonstrated the operational readiness of all pumps in the IST programs, for both units, except for the TDAFW pumps which will be tested during restart activities and the Unit 1 IRS pumps.

The operational readiness of the Unit 1 IRS pumps was determined through an evaluation with the identical Unit 2 IRS pumps. The visual examinations and IST program testing of the AOVs, MOVs, SOVs, manual valves, and comparisons of Unit 2 relief valves to Unit 1 relief valves, provided assurance to the NRC staff that the earthquake did not have any significant impact to the operability of the safety-related valves at NAPS Unit 1 and Unit 2. Based on the evaluations described above, the NRC staff concludes that no functional damage has occurred to the safety-related pumps and valves, in NAPS Units 1 and 2. The NRC staff also concluded that the resumption of plant operation, in either unit, will not result in undue risk to the health and safety of the public.

6.0 CONTAINMENT AND HEATING, VENTILATION AND AIR CONDITIONING (HVAC) SYSTEMS

6.1 Containment Structure

6.2 Containment Isolation Valves

The licensee performed inspections on the containment isolation valves to assess significant physical or functional earthquake-related damage to SSCs. The licensee developed a methodology for performing these inspections consistent with EPRI NP-6695. In a letter dated October 3, 2011 (Serial No. 11-566; Reference 4), the licensee responded to an NRC RAI, and provided the results of 111 Unit 1 containment isolation valve stroke-time tests.

From the licensee's test results, the only failures identified were three valves that closed, but failed their IST stroke time test (1-CC-TV-102A, 1-MS-TV-101A, and 1-MS-TV-101B). The licensee stated that these valves will be repaired prior to Unit 1 restart. An additional valve (1-CC-TV-104B) indicated a negative trend in stroke time. The licensee investigated and determined that the valve stroked acceptably, but one of the two position limit switches needed adjustment. The repairs have been completed.

The failures detected on Unit 1 were very few and minor in nature, typical of what would be found during routine scheduled surveillance, and did not indicate any significant loss of function or systematic damage from the earthquake to isolation valves for both units. As stated above, all repairs have been completed for Unit 1. Testing on the Unit 2 isolation valves was completed satisfactorily.

The NRC staff has reviewed the licensee's results of stroke time tests performed on Unit 1 containment isolation valves and determined that this satisfies the criteria in EPRI NP-6695 and, therefore, is acceptable. Based on satisfactorily stroke time test of Unit 1 containment isolation valves and the Unit 2 containment isolation valves (Reference 18), including repairs and adjustments that were needed, the NRC staff concludes that no functional damage has occurred to the containment isolation valves such that the resumption of plant operation will not result in undue risk to the health and safety of the public. Containment isolation valve leakage is addressed separately in the following section.

6.3 Containment Leakage Integrity

According to the licensee, a methodology was developed for performing inspections to assess significant physical or functional earthquake-related damage to SSCs. Inspections were performed by the licensee's civil engineering personnel on both the inside of the containment building and the exterior concrete cover, using EPRI NP-6695 as a guide to determine if there was any significant damage attributable to the seismic event. The licensee identified no findings that would adversely affect the leakage integrity performance of containment.

The licensee stated that its Technical Requirements Manual (TRM) 3.6.2, "Containment Leakage Rate," Surveillance Requirement (TSR) 3.6.2.7 was completed following the seismic event and found no issues attributed to the earthquake affecting containment integrity. TSR 3.6.2.7 requires performance of a general visual examination of the accessible interior and exterior surfaces of the containment and components including the liner plate for structural problems which may affect either the containment structure leakage integrity or the performance of the Type A test. The NRC staff was satisfied with the scope of this SR, as it meets the intent of the 10 CFR Part 50, Appendix J, general visual inspection of the containment requirements, as well as industry guidance contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

According to the licensee, post-seismic civil/structural inspections of the Unit 1 and Unit 2 containment exteriors were completed by the licensee with the use of a crane and man-basket. The licensee identified no areas of concern. Additionally, readily accessible areas of the containment liner were thoroughly inspected for seismic defects during the post earthquake system inspections and none were identified. The licensee stated that potential high stress areas inside and outside of Unit 1 and Unit 2 containments were inspected including the following:

- Electrical Penetration Area
- Mechanical Penetration Area
- Equipment Hatch
- Personnel Hatch
- Main Steam and FW Line Penetrations in Main Steam Valve House (MSVH)
- Safeguards Building Penetrations

The licensee confirmed by letter dated November 3, 2011 (Serial No. 11-520C; Reference 18), that Appendix J testing was completed for the equipment hatch, personnel and escape hatches, and the containment purge valves in accordance with technical specification requirements. The NRC staff agrees that the technical specification controls over performance of this testing is sufficient to ensure proper leakage performance of these penetrations prior to the resumption of power operations.

By letter dated October 3, 2011, the licensee reported that 10 CFR 50 Appendix J, Type B and Type C testing, was satisfactorily performed on Unit 2 with normal results, well within allowable values. Inspections, valve indications, and periodic as-found local leak rate tests to measure leakage of specific components in NAPS Unit 2 indicate no significant damage that would affect the functionality of the containment leakage integrity performance. The Type B leakage testing

results were 7 percent of the average annual Type B leakage, which is typical of Type B testing performed in previous outages at NAPS. Actual Type B leakage is 4.3 percent of the allowable limit of the summation of the individual penetration limits and 0.055 percent of the allowable limit of 0.6 La for all Type B and C leakage.

According to the licensee, as of October 3, 2011, 79 valves have been tested with three having leakage. Only one valve (2-IA-250) is above its administrative limit. According to the licensee, this valve had been planned to be replaced with an improved valve this outage because of its leakage history. This valve will be tested more frequently until acceptable leakage history has been established. According to the licensee, the results of Type C testing of Unit 2 valves are further indication that Unit 1 and 2 containment integrity was not impacted by the seismic event.

Consistent with EPRI topical report NP-6695, Section 5.3.2, because no significant functional damage was observed during the focused inspections, the licensee did not conduct an integrated leak rate test on either the Unit 1 or Unit 2 Containments. The NRC concurs with this approach based upon conformance to the endorsed EPRI guidance and the results of the licensee and NRC regional inspections of the containment structure. The NRC regional inspections are described in the NRC AIT report (Reference 30).

On the basis that there was minimal visual damage found on both units, along with satisfactory 10 CFR Appendix J, Type B and Type C, test results on Unit 2, the NRC staff concludes that Unit 1 would have similar Type B and Type C test results and that the containment leakage integrity in NAPS, Unit 1 would also retain functionality. Further, on the basis of successful Type B and Type C testing results, as well as the damage assessment of the containment structure, the NRC staff concludes that no functional damage has occurred that adversely impacts containment integrity such that there is reasonable assurance that continued operation of NAPS will not result in undue risk to the health and safety of the public.

6.4 Heating, Ventilation and Air Conditioning (HVAC)

6.4.1 Emergency Core Cooling System (ECCS) Pump Room Exhaust Air Cleanup System (PREACS)

The ECCS pump room exhaust air cleanup system (PREACS), which includes both the safeguards area exhaust system and the auxiliary building central exhaust system, provides ventilation for these two areas. The safeguards area exhaust system is automatically aligned to the auxiliary building filter banks upon a containment depressurization actuation signal, and the auxiliary building central exhaust system is manually aligned to the filter banks by post-LOCA emergency procedures. The common high-efficiency particulate air/charcoal filter assemblies are located in the auxiliary building fan room to filter any of the auxiliary exhaust systems subject to radioactive contamination. These exhaust systems are connected to a common manifold, to selectively serve (1) auxiliary building exhaust, (2) fuel building exhaust, (3) decontamination building exhaust, (4) safeguards area exhaust, and (5) the containment purge exhaust.

According to the licensee, a comprehensive external inspection of the safety-related ECCS PREACS ventilation duct work, dampers and filters was performed after the seismic event. The licensee identified no indications of any seismic related damage on the duct work, supports, or

components. An ECCS PREACS flow test was performed on August 27, 2011, with no issues identified when stroking the dampers. The ECCS PREACS Train A filter (1-HV-FL-3A) in-place test, prior to either unit entering Mode 4, has been satisfactorily completed as stated in Reference 18.

The NRC evaluated the licensee's scope of tests and inspections on the ECCS PREACS and concluded that it meets the EPRI NP-6695 criteria, and therefore, is acceptable. Further, based on the comprehensive external inspection of the safety-related ECCS PREACS ventilation duct work, dampers and filters, a successful ECCS PREACS flow test and the ECCS PREACS, Train A, in-place test meeting the technical specification acceptance criteria prior to Mode 4, the NRC staff concludes that no functional damage has occurred to ECCS PREACS charcoal filter banks such that the resumption of plant operation will not result in undue risk to the health and safety of the public.

6.4.2 Control Room

According to the licensee, a comprehensive inspection of the building structures after the seismic event, which included the walls, floors, and ceilings that form the shared control room envelope (CRE) pressure boundary was performed. In addition, the licensee stated that it had performed a comprehensive inspection of the duct work, supports and components that support the CRE pressure boundary. The licensee found no indications of any structural damage that would affect the integrity of the CRE pressure boundary. A sampling of 55 fire barriers penetrations was also inspected throughout the Unit 2 emergency switchgear room and was determined to be in good condition with no signs of degradation. The licensee indicated in Reference 18 that the measurement of the CRE pressure relative to the external areas adjacent to the CRE pressure boundary has been completed.

Based on the inspection of the CRE pressure boundary and the completion of the measurement of the CRE pressure relative to the external areas prior to entering Mode 4, the NRC staff concludes that the control room in-leakage remains less than assumed in the control room habitability dose analysis. Therefore, there is reasonable assurance that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.

7.0 INSTRUMENTATION AND CONTROLS SYSTEMS

The NRC staff reviewed the licensee's submittals in the instrumentation and controls (I&C) area. In particular, the NRC staff evaluated the adequacy of the scope and the reasonableness of the conclusions reached regarding the licensee's visual and physical inspections following the seismic event, and the adequacy of surveillance testing that was performed to demonstrate that I&C systems required to be operable in accordance with the plant technical specifications are indeed operable. Additionally, the NRC staff has evaluated the licensee's actions and plans for ensuring that I&C systems that are not described in the NAPS technical specifications but that warrant programmatic controls to ensure that the reliability and availability of such systems are being maintained, will be appropriately monitored during the start-up following completion of all licensee pre-startup activities.

7.1 Physical Inspections and Tests Conducted to Identify Apparent Damage and Potential Loose Electrical Connections

While some types of damage to installed instrumentation or instrument support hardware would be apparent (i.e., visible) to plant personnel during the conduct of plant walkdowns following a seismic event, the NRC staff was also concerned that the seismic motion experienced on August 23, 2011, could have resulted in latent functional degradation of such instruments. For example, the seismic motion could have adversely affected the integrity of electrical connections to locally mounted instruments and the edge connectors of electronic circuit boards mounted in card frames within electronic cabinets throughout the plant, thus rendering the performance of such instruments and controls unreliable.

In its letter to the NRC staff of October 3, 2011 (Serial No. 11-566; Reference 4), the licensee outlined its evaluation and conclusions reached following the walkdowns and physical inspections conducted after the event. The licensee's walkdowns and physical inspections included a sampling of electrical components within various key safety systems at NAPS, for which the electrical connections were inspected in detail. The licensee identified that in addition to physical inspections conducted specifically to identify the existence of loose wiring connections, surveillance testing (as described in detail below) was conducted for various systems and local instrumentation. None of these tests revealed any intermittent circuit performance, in the form of erratic voltage or current anomaly indications on measurement and test equipment that would be indicative of a loose connection. Specifically, as noted in the licensee's letter dated October 3, 2011, electrical connections for the reactor protection system (RPS), rod control system, and emergency power buses were inspected, and no abnormalities were identified. Calibration surveillance tests and subsequent functional performance tests were conducted for the RPS systems (safety-related) of both units, and for all three loops of the Unit 2 feedwater control system steam generator level controls (non-safety-related.)

During both types of surveillance testing, successful performance of the tests depends in large part on the continued integrity (continuity) of electrical connections. The NRC staff notes that during the conduct of such testing, the physical manipulation of wiring due to the opening and closing of electrical junction boxes, instrument covers, and control panel doors, as well as the placement of test probes from measurement and test equipment onto the terminals of instrumentation being tested or calibrated, poses challenges to the integrity of such electrical connections. The NRC staff notes that potentially degraded connections to components that could exist during such testing would become apparent to the technicians during the conduct of this testing in the form of erratic indications on the measurement and test equipment used or in the intermittent functioning of the instrument loop or circuit during functional testing. However, the licensee noted in its response dated October 3, 2011, to the NRC staff that "[n]one of the calibrations or subsequent performance tests found any indication of a loose or damaged connection."

Further, during calibration and functional performance testing, the functionality of logic and analog signal boards within logic cabinets is tested. According to the licensee, during such testing following the August 23, 2011, seismic event, logic board edge electrical connectors within the RPS and rod control system cabinets were inspected as part of the performance and calibration testing and the proper seating of the circuit boards was ensured through physical inspection. The NRC inspection staff noted that the front edges of most of the modular control

and protection board systems inspected are retained by thumbscrews into threaded holes on the front of the card frame (chassis) to ensure a tight fit of the electrical card edge connector at the back of the chassis into the mating card edge connectors. The electrical connections of electrical support systems for technical specification-related I&C equipment were also inspected and tested. For example, maintenance and inspection of the 2J Emergency Switchgear 4160 Volt (V) Bus was conducted. During such testing and inspections, insulation resistance readings of conductors and micro-resistance readings of the bus-to-bus bolted connections are taken, and proper bolt torque is ensured. According to the licensee's letter dated October 3, 2011, throughout all of this testing, "there have been no reports of a loose connection in any of the testing or inspections performed after the seismic event." Additionally, ongoing preventative maintenance thermographic inspections conducted after the seismic event has not identified any increase in hot spots indicative of loose electrical connections.

7.2 Resolution of Instrumentation Performance Anomalies Observed During the Seismic Event

According to the licensee, during and immediately following the seismic event on August 23, 2011, several occurrences of apparently anomalous behavior of instruments and controls in the plant were captured by the plant sequence of events recorder and post-trip review logs of the plant process computer. After evaluating each occurrence of anomalous performance in detail, the licensee explained the root cause of each occurrence, demonstrate that the performance would have been expected under the conditions present during the event, and has reached a conclusion that no unresolved instrumentation operability issues associated with these anomalous performances exist.

The NRC AIT members were tasked with identifying any unexplained anomalies in plant response or equipment performance during or after the earthquake, and to assess the licensee's activities related to identification of additional failure mechanisms and damage to safety-related equipment due to the event. As part of their efforts in this task, the AIT members performed an overview of the licensee's efforts to evaluate these anomalous performances, as described in the AIT inspection report dated October 31, 2011 (Reference 30). The AIT report concludes that additional NRC review will be needed in this area, and is being tracked by an unresolved item (URI) and assigned it a number for tracking (URI 05000338, 339/2011011-07: Safety-related Instrumentation Anomalies.) This issue will be followed up as part of the NRC's Reactor Oversight Program. While the investigation of the unresolved item will continue to determine if a licensee performance deficiency exists, the NRC staff evaluated the licensee's actions with regard to explaining each anomaly and has concluded that the issues did not affect instrument functionality.

7.3 Performance of Westinghouse 7300 Series Protection and Control Boards

During an inspection of the licensee's actions with regard to its "Restart Readiness" program, the NRC inspection staff noted that the licensee had identified that at the time of the seismic event occurrence, as many as 94 of the several hundred Westinghouse 7300-series control boards used for protection and control functions (i.e., both safety and non-safety) were not of the models meeting the latest seismic qualification levels offered by the vendor.

By letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), in response to an NRC RAI, the licensee stated that the qualification standard for the NAPS 7300 Process Protection System is Westinghouse Report WCAP-7817, "Seismic Testing of Electrical and Control Equipment," Supplement 4, November 1972, which meets the seismic design standards in effect when NAPS was originally licensed in 1978 (Unit 1) and 1980 (Unit 2). The licensee further stated that Westinghouse had performed further seismic testing of the 7300 series control boards, as documented in Westinghouse Report WCAP-8687, Supplement 2 E13C, Revision 2, November 1988, for its other customers to levels that were higher than required for the NAPS site. This testing showed that at higher required response spectra (RRS) levels, four types of boards that are of the same type as four of the types used at NAPS exhibited performance anomalies at the higher RRS levels tested. Such anomalies included relay chatter for mercury-wetted relays such as those mounted on the nuclear tracking driver (NTD) card and nuclear temperature channel (NTC) test boards. The NRC staff notes that, in its Information Notice (IN) 83-38, “Defective Heat Sink Adhesive and Seismically Induced Chatter In Relays Within Printed Circuit Cards,” dated June 13, 1983 (Reference 33), a similar relay chatter anomaly was described for the NTC board resulting from seismic testing performed by Westinghouse in 1982 at higher RRS levels than that required for the NAPS plant and reported in a 10 CFR Part 21 report issued by Westinghouse on June 1, 1983. According to the licensee, during the August 23, 2011, earthquake, there were no apparent unexplained anomalies (such as unexpected alarms or spurious equipment operations due to spurious relay operation) during the event that were attributable to relays mounted on these installed 7300 series boards, including either the newer version and older version 7300 series boards.

In its letter dated October 20, 2011, the licensee reported that recent fragility testing conducted by Westinghouse as a result of the August 23, 2011, earthquake, has demonstrated that the occurrence of relay chatter is not evident for either the NTC or NTD boards until the test response spectra (TRS) is increased to three-to-four times higher in magnitude than the NAPS in-cabinet required response spectra levels.

7.4 Performance Tests and Surveillances Conducted to Demonstrate “No Functional Damage”

In addition to the potential for damage or loose connections of plant instrumentation and control equipment, the NRC staff was concerned that seismic motion in excess of the design basis for the plant experienced during the August 23, 2011, seismic event could have resulted in an adverse impact on instrumentation and control system reliability and availability. By letter dated September 27, 2011 (Serial No. 11-520A; Reference 2), the licensee stated that it has followed the guidance of Appendix B, “Typical Surveillance Tests for PWRs,” within EPRI NP-6695, to identify additional tests and inspections prior to restart actions that have been taken after determining that there was no apparent physical damage to plant SSCs. Section 5 of EPRI NP-6695 provides criteria for performing detailed visual inspections of equipment and structures selected for a “focused” post-shutdown inspection. According to the guidelines of EPRI NP-6695, if no significant physical or functional damage is found during this focused inspection, it can be concluded that the earthquake was non-damaging. The EPRI guideline provides guidance for conducting further evaluations of the effects of the earthquake on the functionality of plant equipment to be performed. The NRC staff requested that the licensee provide a description of the inspections, tests, and analyses the licensee has performed to demonstrate that the instrumentation and control systems required to be operable by Technical

Specifications or are otherwise risk-significant, have sustained no functional damage resulting from the earthquake.

In its letter dated September 27, 2011, the licensee stated that within Appendix B, "Typical Surveillance Tests for PWRs," of EPRI NP-6695, guidance is provided for developing a list of surveillances that should be performed to demonstrate the availability and operability of instruments and control systems important to safety or required to mitigate the consequences of an accident as identified in the plant TS. The testing recommended in EPRI NP-6695, Appendix B includes "Testing and Calibration of Instrumentation," "Verification of the Control Logic in Reactor Protection Systems and Engineered Safety Systems," and "Measurement of SCRAM Insertion Times of Control Rods." In its letter of October 28, 2011 (Serial No. 11-566D; Reference 14), the licensee provided a detailed list of all surveillances has conducted to demonstrate functionality of systems and components for Units 1 and 2. The NRC staff reviewed the list and concluded that Instrument Calibration Procedures (ICPs), Channel Operational Tests (COT), and Trip Actuating Device Operational Tests (TADOT) have been successfully completed for all of the Reactor Trip System (RTS) and the Engineered Safety Features Actuation System (ESFAS) functions in accordance with the noted surveillance requirements. The NRC staff notes that the performance of instrument calibration procedures requires the calibration/verification of the loop transmitter(s)/remote sensor(s), the active/adjustable 7300 circuit cards, indicator(s), recorders, and the check of control room alarms, trip status, computer points, and channel test/bistable test switches, and the functional test of protection system bistables (i.e., analog comparator "NAL" Cards) is embedded in the Instrument Calibration Procedure.

Additionally, the licensee has completed several integrated system surveillances, such as the Loss of Offsite Power/Loading of Emergency Equipment (LOOP/LOCA) test. Such integrated testing provides a good indication that system response time and functional capability has not been degraded as a result of the seismic event. For example, the performance of the surveillance test for verifying a simulated LOOP in conjunction with the simulation of an ESF actuation signal is described in the licensee's letter of October 20, 2011 (Serial No. 11-566C; Reference 12). Successful completion of this type of test provides assurance to the NRC staff that critical time delay relay settings have not shifted from their required settings in response to the seismic event, and that key safety-related components will perform their required safety functions with the proper response times. Also, rod drop timing tests to be conducted during start-up while in Mode 3 at greater than 500 degrees reactor temperature, will provide adequate assurance that the reactivity control function will continue to respond to events within the response times that have been analyzed for the plant licensing basis, as well as exercise the rod control system prior to criticality.

7.5 Evaluation of Key Non-Technical Specification I&C Systems and Components

The NRC staff was also concerned that the reliability of normal plant control systems used to maintain the reactor within licensed operating parameter requirements (e.g., those affecting reactivity control, or those regulating heat removal from the primary loop, such as the rod control system, feedwater controls, turbine electrohydraulic controls, steam dump controls, etc.) could have been adversely affected by the seismic motion experienced during the event. In its letter of October 3, 2011 (Serial No. 11-566; Reference 4), the licensee described its actions

regarding calibration or functional testing performed for systems important to safety. Examples of the Unit 1 instrumentation that were calibrated or functionally checked include the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC), the Nil Ductility Transition (NDT) Low Temperature Overpressure Protection (LTOP), Safety Injection Flow Measurement Instrumentation, Inadequate Core Cooling Monitoring System, Vibration and Loose Part Monitoring System, Seismic Monitoring System, Main Turbine Electrohydraulic Control System, Main Turbine Overspeed Protection System, and certain process and area Radiation Monitoring Systems. The licensee's letter of October 28, 2011 (Serial No. 11-566D; Reference 14), also provided a detailed list of all non-Technical Specification related instrumentation surveillances that were conducted for the Unit 1 and 2 Control and Balance of Plant loops. The NRC staff evaluated this list and finds that the instrument loops tested represent the most critical non-safety-related reactor control systems needed to ensure proper reactor system normal operations and mitigate normal anticipated transients. Examples include: Pressurizer Pressure and Level Controls; Steam Generator Level Controls; Tavg Steam Dump and Steam Dump Controls; Tavg Rod Control and Power Mismatch Controls; Steam Generator Atmospheric Relief Valve Controls; Feedwater Bypass Flow Controls; Refueling Water Storage Tank, Emergency Condensate Storage Tank, Casing Cooling Water Tank, Volume Control Tank, and Chemical Addition Tank Controls. Additionally, the licensee performed surveillances to ensure operations of accident monitoring and leakage detection system instrumentation, as listed in the October 28, 2011, letter.

To provide additional assurance that upon restart the plant will not be challenged by transients or anticipated operational occurrences due to degradation of normal plant control systems, the NRC staff requested the licensee to describe what provisions have been made for monitoring the performance of key normal reactor system and secondary system control systems during the start-up of each unit at NAPS to ensure that any potential degradation in performance is identified early and corrected while still operating at plant dynamic conditions consistent with that of low power operations, prior to increasing toward full power operations. In its letter of response to the NRC staff of October 18, 2011 (Serial No. 11-566B; Reference 11), the licensee stated that before reactor startup of either unit, the high power trip setpoints for the power range neutron monitoring instrumentation system will be set conservatively low until core analysis via flux mapping using information from the in-core detectors can confirm proper response of the ex-core detectors. The licensee made a commitment to implement hold points at 30 percent, 75 percent, and 96 percent reactor power to perform such core flux mapping and validate response of the power range neutron monitoring system. Further, the licensee outlined its plans to implement an augmented management and system engineering team to monitor the performance of the normal primary and secondary plant control systems as power is increased during start-up, to ensure that the performance of these controls is within required ranges.

7.6 I&C Equipment Seismic Qualification Margin

The NRC staff was also concerned that since several DBE acceleration values were exceeded for at least a portion of the frequency spectrum, there is a possibility that the remaining seismic qualification life of specific I&C components may have been diminished in terms of seismic event withstand capability. Typically, qualification levels for specific I&C components are sufficient to allow for five OBEs and one SSE (DBE in the NAPS terminology), for the required response spectra applicable to the plant. The NRC staff requested the licensee to perform an analysis of the relationship between the seismic qualification levels used during type testing for

a sample of the various types of safety-related I&C components as compared with the response spectra computed to be present at the specific location of the installed instrumentation as translated via amplification factors due to equipment location within the plant from the time history recordings. The NRC staff notes, however, that typically, I&C components manufactured by several vendors are qualified to a much higher level of seismic activity, based upon an envelope of various seismic response spectra representative of nuclear plants all around the United States (more than 8.5 g in some cases.)

In its letter of October 20, 2011 (Serial No. 11-566C; Reference 12), the license provided a qualitative analysis to demonstrate that the levels of seismic response test spectra to which the I&C systems installed at NAPS have been qualified are significantly greater than that experienced on August 23, 2011. This analysis provides the NRC staff with reasonable assurance that there is be adequate margin to ensure continued reliable operation of safety-related I&C equipment during a future seismic event. The recorded time-history data of the outputs of the tri-axial accelerometers located at the containment basemat during the August 23, 2011, event, indicate that the earthquake exceeded the NAPS DBE in the 2 to 10 Hz range, on average, by about 12 percent in the North-South direction, by about 21 percent in the vertical direction, and none in the East-West direction. The effective strong motion duration of the August 23, 2011, earthquake was about one second in the North-South direction, about 3.1 seconds in the East-West direction, and about 1.5 seconds in the vertical direction.

To confirm that there is existing margin remaining between the design basis and the seismic event in the seismic qualification of I&C equipment used to initiate protective actions at NAPS, the licensee performed a sampling evaluation of various items of I&C equipment qualified for use at NAPS through the plant's seismic testing and qualification program. The licensee's sample of I&C equipment included key types of instruments and controls used within the control and protection systems at NAPS. This sample included Rosemount pressure and differential pressure transmitters, Barton differential pressure transmitters, Foxboro pressure and differential pressure transmitters, Westinghouse 7300 series control and protection boards within the process protection system cabinets, Westinghouse Nuclear Instrumentation System (NIS) equipment, Westinghouse Solid State Protection System (SSPS) cabinets, the Westinghouse Inadequate Core Cooling Monitoring System processing and display equipment, and Weed Resistance Temperature Detectors (RTDs).

The NRC staff requested that the licensee describe how seismic qualification remains valid for I&C components that are required to be qualified for seismic events. In its October 20, 2011, response to the NRC staff's request, the licensee noted that the primary industry standard used for seismic qualification of new and replacement mechanical, electrical, and Instrument and Control equipment is IEEE Standard 344-1975, "Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," as endorsed by RG 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants," Revision 1, August 1977 (Reference 34). Although, new and replacement equipment is to be qualified to the requirements of the 1975 or 1987 versions of IEEE Standard 344, according to the licensee, the seismic qualification program at NAPS includes equipment that was developed and qualified for use during the time frame the plant was originally licensed. Therefore, certain installed I&C equipment was originally qualified to the test specifications outlined in Westinghouse report WCAP-7817, dated December 1971. These test requirements parallel the requirements of the IEEE Standard 344-1971 standard. In some cases, the same

instrumentation had been re-tested or re-evaluated in later years by the NSSS vendor or equipment suppliers to confirm performance under conditions that envelope a broad set of seismic characteristics covering the minimum qualification levels needed in many different parts of the country. Such minimum qualification levels used during these later tests are significantly higher than that experienced on August 23, 2011, at the NAPS site. The 1971 standards provided for multiple single-axis testing using sine beat frequencies at conservative applied accelerations delivered over selected discrete frequencies in the range of 0-35 Hz. The 1975 and later testing of components were conducted by applying triaxial shake-table testing over a continuum of applied frequencies in the same required range. With respect to durations and margins in testing, the later seismic tests were performed to simulate five OBE and one DBE event, which are generally triaxial with a typical duration of 30 seconds and minimum strong motion durations of 15 seconds for each test. In all testing, however, the applied motion exceeded the required response spectra for the equipment by a significant margin, and the equipment performance was monitored.

According to the licensee, the test response spectra in shake table testing are required to have at least 10 percent margin over the required response spectra in the entire frequency range, as required by IEEE Std. 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” and as endorsed by RG 1.89, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,” Revision 1, June 1984 (Reference 35).

The licensee’s letter of October 20, 2011, provided an analysis of the seismic qualification testing performed to demonstrate the seismic withstand capability of a sample of key types of instruments and controls used within the control and protection systems at NAPS, representing the majority of all I&C equipment types used in safety protection systems at NAPS. In all cases, the seismic test reports indicated that the equipment within the sample has been shown to be capable of withstanding levels of seismic acceleration significantly greater than that experienced during the August 23, 2011, earthquake. Although, the amplification factors to be applied to the recorded time history data from the August 23, 2011, earthquake have not been applied to determine the precise forcing function applied to the equipment where it is specifically located within the plant, the NRC staff notes that in most cases the applied test forces used in the seismic testing for this equipment was significantly greater (in some cases, orders of magnitude greater) than that experienced at the containment basemat accelerometers. Based on its review of the example test response spectra data submitted by the licensee for these components, the NRC staff concludes that there is reasonable assurance that adequate margin exists beyond the 10 percent margin that is required per IEEE Std. 323-1974.

Given that the August 23, 2011, earthquake was of short duration and had low damage potential; extensive plant inspections performed by both the licensee and NRC staff (for a description of NRC inspections see AIT Report dated October 31, 2011, available at Reference 30) confirm a lack of apparent damage to safety-related SSCs; successful functional, calibration, and response testing of I&C components revealed insignificant deviations in performance from pre-earthquake testing; and the existence of seismic qualification margin in excess of that suggested by industry standards and RGs, the NRC staff has reasonable assurance of no functional damage, and, further, these components remain capable of performing their intended design functions during and after a potential future DBE.

7.7 NRC Staff Evaluation

The NRC staff has evaluated the adequacy of the licensee's inspections, surveillances, and other testing and analysis that was performed following the August 23, 2011, earthquake. In addition, the NRC staff evaluated the responses of the licensee to its requests for additional information, as outlined above. The NRC staff concludes that the sample of visual and physical inspections of electrical connections made by the licensee was sufficient to be able to make a reasonable determination that no apparent significant physical or functional damage has occurred to safety-related I&C equipment at NAPS. Further, the scope of surveillance testing conducted by the licensee is considered by the NRC staff to be adequate for ensuring that all technical specification related I&C systems are operating within calibration and functional test requirements, and that the provisions of the guidelines within EPRI NP-6695 and RG 1.167 (Reference 23) pertaining to I&C systems have been appropriately addressed. Also, as described above, the licensee's actions to perform additional surveillance testing on a sample of non-technical specification, but key important-to-safety systems provide reasonable assurance that a potential failure occurring within one these systems, which could lead to challenges to the plant safety systems, is unlikely. The NRC staff also concludes that the actions planned by the licensee to provide augmented management and technical staff resources to monitor the performance of key non-safety-related reactor and secondary control systems during the start-up of each unit following this earthquake event will provide additional assurance that any latent defects not identified through the inspection and surveillance program described above will become apparent to this augmented staff during low power operations when corrective actions may be taken prior to increasing to power levels where such remedies are difficult to implement.

Further, in its evaluation of the licensee's analysis of the qualification levels for various types of I&C equipment as compared with the level of relative seismic motion actually experienced by installed safety-related instrumentation, the NRC staff has found that there is reasonable assurance that the installed equipment is still capable of reliably performing its required functions in the event of a future earthquake event and thus no functional damage has occurred. This reasonable assurance is based on the significant margin identified between the seismic qualification levels of the instrumentation identified in the sample as compared with the seismic motion actually experienced at the plant during the August 23, 2011, earthquake.

7.8 Instrumentation and Control Conclusions

Based on the summary of its evaluation described above, the NRC staff concludes that no functional damage has occurred to the I&C systems required to be operable per the plant Technical Specifications, and that there is reasonable assurance that plant I&C systems will continue to reliably perform their intended safety functions, such that the resumption of plant operation will not result in undue risk to the health and safety of the public, in accordance with the requirements of 10 CFR Part 100, Appendix A, Section V(a)(2). The NRC staff also has reasonable assurance that any future degradation of the I&C equipment required for maintaining the plant within its technical specification limits, whether created by the August 23, 2011, earthquake or not, can be detected during performance of routine technical specification surveillance requirements or maintenance activities. The licensee's commitments to complete the remaining technical specification-related and other surveillances at appropriate reactor modes, and monitor the performance of key non-safety I&C systems during the plant startup prior to increasing to full power operations will be monitored by NRC Region II personnel (as

described in the North Anna Power Station Post-Earthquake Restart Readiness Review Restart Readiness Inspection Plan 05000338, 339/2011011) and the North Anna Station NRC resident inspectors.

8.0 ELECTRICAL SYSTEMS

Regarding electrical systems, the NRC staff reviewed the documentation provided by NAPS subsequent to the August 23, 2011, earthquake to determine whether the inspections, tests (i.e., technical specification surveillance requirements), and analysis were adequate to demonstrate that the electrical equipment at NAPS, Units 1 and 2, remains capable of performing its intended design functions subsequent to this seismic event.

An NRC Augmented Inspection Team (AIT) was sent to the NAPS site to review the preliminary observations following the earthquake. The inspection was conducted by the NRC's Region II staff from August 30 – October 3, 2011. As part of its inspection, the AIT conducted a walkthrough inspection of electrical equipment. The AIT did not observe any significant damage to electrical equipment at either NAPS unit or the switchyard. The results of the AIT review may be found in an inspection report dated October 31, 2011 (Reference 30). The NRC staff finds that this confirms observations made from comparable inspection activities conducted by the licensee.

The electric power system at NAPS, Units 1 and 2, is described in Chapter 8 of the UFSAR for each unit and is outlined below:

8.1 Offsite Power System

The output of the two NAPS units is delivered to a 500 kilovolt (kV) switchyard through the unit main step-up transformers, as described in Section 8.2 of the NAPS UFSAR. The switchyard serves three 500 kV lines and one 230 kV line. The plant is connected to the switchyard by two 500 kV transmission lines, three 34.5 kV underground lines and two 34.5 kV overhead lines. Power supplies for the 500 kV switchyard controls are provided by two direct current (DC) systems from separate and completely independent batteries and chargers.

The preferred alternating current (AC) power source is the switchyard, which is connected to both NAPS units via three reserve station service transformers. The reserve station service power is available at all times to the safety-related equipment and has the capacity to drive the station auxiliaries in the event of a loss of the normal AC power supply.

In its letter dated October 10, 2011 (Serial No. 11-577; Reference 7), in response to an NRC staff RAI, the licensee stated that it initiated an inspection program of the NAPS switchyard and large power transformers, based on the guidance provided by Regulatory Guide (RG) 1.167, "Restart of a Nuclear Power Plant Shut Down by a Seismic Event," Electric Power Research Institute (EPRI)-NP-6695, "Guidance for Nuclear Plant Response to an Earthquake," and operating experience. The inspection focus was to comprehensively inspect the entire switchyard to determine the impact of the August 23, 2011, seismic event on switchyard components. The licensee's inspection program included: switchyard equipment, the generator step-up units, station service transformers, reserve station service transformers, and the disconnect switches located in the mini-switchyard, as well as line zone equipment one

substation away from NAPS Units 1 and 2. The licensee's inspection criteria included guidance from equipment manufacturers and operating experience from the industry in the United States and Japan. In its October 3, 2011 (Serial No. 11-566; Reference 4), response to a NRC staff RAI, the licensee stated that the focus areas of the internal inspections were as follows: 1) wiring pull-out from terminal blocks, 2) damaged insulators (porcelain, ceramic, or plastic), 3) wiring pull-out from lugs, 4) wiring harness spacing issues, 5) backed out or missing hardware from electrical bus work, 6) foreign material, 7) components that have become loose from electrical sockets, 8) insulator damage to conductors, 9) signs of electrical flashover, 10) odd smells or sounds of resonance, and 11) mechanical and electrical misalignment. The licensee documented its inspection findings and entered deficiencies into its corrective action program. The listing of identified conditions was provided to the NRC staff by letter dated October 10, 2011 (Serial No. 11-577; Reference 7). The NRC staff reviewed the list of conditions, and agrees that the licensee's corrective action program provides the appropriate controls to disposition these conditions. Therefore, the NRC staff finds that the licensee's inspections and related corrective actions provide reasonable assurance that the offsite power supply from the switchyard has sufficient integrity to support operation of NAPS, Units 1 and 2, following the August 23, 2011, seismic event and that no functional damage has occurred.

The NRC staff requested the licensee to describe the impact of the August 23, 2011, earthquake on the main transformers, station service transformers, and reserve station service transformers. The licensee provided its response to the NRC staff's RAI in letter dated October 20, 2011 (Serial No. 11-566C; Reference 12). Based on its review of the licensee's response, the NRC staff understands that as part of its evaluation the licensee examined the oil and dissolved gases in the main transformers, station service transformers, and reserve station service transformers in accordance with the Institute of Electrical and Electronics Engineers (IEEE) C57.104-2008, "IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers." According to the licensee, it did not identify any negative or adverse trends as a result of its review. Since the licensee did not identify any negative or adverse trends in its evaluation of transformer oil and dissolved gases, the NRC staff finds that the main transformers, station service transformers, and reserve station service transformers should be capable of performing their intended design function following the August 23, 2011, earthquake.

The August 23, 2011, earthquake led to the actuation of several transformers' Fault or Sudden Pressure Relays (SPRs). The reserve station service transformers, which provide off-site power to the station, were among the affected equipment; therefore, the electric transmission network was unable to provide power to the site for approximately 3 hours. The SPR is a type of relay used to detect internal, small magnitude faults that other protective devices, such as differential and overcurrent relays, do not normally observe. When a fault occurs inside a transformer, the fault arc produces gases that create a sudden increase of pressure inside the transformer. This relay will react to the fast increase in pressure and trip the transformer before the fault evolves into a larger, and more damaging, disturbance.

Based on the actuation of the SPRs, the NRC staff requested the licensee to provide (1) an overview of the analyses performed to validate that the relay actuation should have occurred for a non-transformer related external event considering that the purpose of the relays is to detect internal transformer faults, and (2) details on testing performed on the reserve station service transformers to validate their integrity and capability to perform their intended functions.

The licensee provided its response to the NRC staff's RAI in a letter dated October 20, 2011 (Serial No. 11-566C; Reference 12). Based on its review of the licensee's response, the NRC staff understands that as part of its evaluation the licensee examined the oil and dissolved gases in the main transformers, station service transformers, and reserve station service transformers in accordance with the IEEE C57.104-2008. Since the licensee did not identify any indications that an internal transformer fault occurred during its evaluation of oil samples and dissolved gas, the NRC staff has reason to conclude that actuation of the SPR relays was due to the ground acceleration produced by the August 23, 2011, earthquake and not due to transformer internal faults.

In its October 3, 2011 (Serial No. 11-566; Reference 4), response to an NRC staff RAI, the licensee confirmed that it has evaluated the impact of a dual unit trip at NAPS and have not identified any concerns with either the adequacy of equipment voltages or separation from offsite power via degraded voltage relays. Based on our review of the information submitted by the licensee, the NRC staff finds that the licensee has considered the impact of a dual unit trip at NAPS and demonstrated that the impact of this event on the NAPS plants would be minimal given the electrical system configuration.

In its October 18, 2011 (Serial No. 11-566B; Reference 11), response to an NRC staff RAI, the licensee stated that the undervoltage (UV)/degraded voltage (DV) relays were calibrated post earthquake and compared to previous calibration data for the relays and timers. The NRC staff reviewed the relay test data provided by the licensee. Based on our review, the NRC staff did not identify any indications that the August 23, 2011, earthquake caused damage to these relays. The NRC staff also finds that the licensee's test data indicates that each UV/DV relay tested within the acceptance criteria. Therefore, the NRC staff concludes that no functional damage occurred to the relays.

8.2 Onsite Power System

The NAPS onsite electric system includes electrical equipment necessary to generate power and deliver it to the high-voltage switchyard. It also includes power supplies and equipment, including batteries, necessary to distribute power, both AC and DC, to the normal (non-safety-related) auxiliaries, and emergency (safety-related) auxiliaries. The onsite electric system also supplies power for control and instrumentation, and is designed to provide dependable sources of power and to distribute it to the plant auxiliaries.

The standby emergency AC power source for each unit consists of two emergency diesel generators (EDGs). The standby AC power system has adequate capacity to supply the safety-related equipment. The standby AC power source, during the periods of interrupted preferred power, automatically supplies safety-related equipment.

An alternate AC (AAC) diesel generator is available to provide emergency power in the event of a Station Blackout (SBO). The AAC system is auto-started by an SBO event. Operator action is required to align the AAC diesel generator output to the desired emergency bus.

In its September 17, 2011, letter, the licensee noted that it has completed a comprehensive external and internal inspection in accordance with a post-seismic event plant procedure for 4160 volts (V) AC, 480 V AC, Vital/Semi-Vital 120 V AC, and 125 V DC equipment. The

licensee further noted that it used the guidance in RG 1.167 to develop a methodology for performing inspections to assess significant physical or functional earthquake-related damage to SSCs. The licensee noted that it did not identify any significant physical or functional damage to the electrical systems and components that would render them incapable of performing their design function. When crediting NAPS, Unit 2 inspection activities for demonstrating acceptability of NAPS, Unit 1 electrical components, the NRC staff confirmed that the electrical equipment (i.e., batteries, bus work, breakers) and Instrument and Control equipment (e.g., protection and control cabinets) are similar and functionally equivalent and the equipment orientation and location is the same in each unit. Based on this information, the NRC staff finds that the effect of the August 23, 2011, seismic event on electrical equipment in NAPS, Unit 1 should be the same as NAPS, Unit 2 and vice versa. Therefore, the NRC staff finds that the inspections of NAPS, Unit 1 electrical and Instrument and Control equipment that is equivalent and installed in the same orientation and general location (e.g., elevation) are acceptable to demonstrate the adequacy of the electrical and Instrument and Control equipment in NAPS, Unit 2 and vice versa.

Using the guidance in Appendix B of Electric Power Research Institute (EPRI) NP-6695, which is endorsed by RG 1.167, the licensee also developed a list of surveillance tests that needed to be performed prior to restarting NAPS, Units 1 and 2. The licensee performed these tests to demonstrate the availability and operability of components and systems, identified in the NAPS, Units 1 and 2 Technical Specifications, important to nuclear safety or required to mitigate the consequences of an accident. The NRC staff concluded that these tests demonstrated that the electrical equipment is capable of performing its design function.

After reviewing the September 17, 2011, letter, the NRC staff developed several questions related to the licensee's evaluation of electrical equipment following the August 23, 2011, earthquake. The licensee responded to these questions in the supplements listed in Section 1.0 of this SE.

In its October 3, 2011 (Serial No. 11-566; Reference 4), response to a staff RAI, the licensee provided detailed information on the inspection activities associated with the safety-related batteries at NAPS, Units 1 and 2. The licensee stated that it did not identify any abnormal results when using thermography to find potential evidence of battery degradation. The licensee also performed visual inspections of the battery rack anchorages, feeder cable tie wraps, and battery cell jars (internal and external). The licensee did not identify any visible damage as a result of its battery inspections. The licensee measured battery cell parameters (temperature, specific gravity, electrolyte level, and individual cell voltages) for the NAPS Unit 2 battery banks with no abnormal or adverse trends noted from pre-seismic event results.

The licensee also performed modified performance discharge testing of the Unit 2 batteries with no adverse trends noted. The NRC staff reviewed the results of the modified discharge tests and compared them to previous tests to confirm that the batteries were not in a degraded condition from a capacity perspective. Based on its review of the battery test results, provided by the licensee in letter dated October 18, 2011 (Serial No. 11-566B; Reference 11), the NRC staff finds that batteries 2-II, 2-III, and 2-IV appear to be healthy, with adequate capacity to perform their intended design function. The NRC staff notes that the 2H and 2J batteries, while shown to have a capacity greater than 100 percent, should be considered to be in a degraded condition since the capacity for each of these batteries has decreased by greater than

10 percent from the previous test (as described in the NAPS technical specifications and IEEE Std. 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications"). The NRC staff also notes that the capacity of 2-I battery decreased by almost 10 percent from the previous test and may warrant increased attention during routine surveillance testing and monitoring. While these batteries have shown a decrease in capacity, the remaining capacity is above the technical specification limits. The NRC staff considers this issue to be an item that can be resolved within the licensee's corrective action program, subject to NRC inspection, outside of the NRC staff's review efforts associated with the NAPS seismic event. Based on the available capacity (Unit 2 safety-related batteries only), no visible damage, and no abnormal thermography results, the NRC staff finds that the NAPS safety-related batteries remain capable of performing their intended design functions and that no functional damage has occurred to the NAPS safety-related batteries as a result of the August 23, 2011, earthquake.

As reported by the licensee in the submittal dated September 17, 2011, based on the recorded time-histories of the Kinemetrics instrument at the Containment basemat, the August 23, 2011, earthquake exceeded the NAPS DBE in the 2 to 10 Hertz range, on average, by about 12 percent in the North-South direction, by about 21 percent in the vertical direction and none in the East-West direction. The effective strong motion duration of the August 23, 2011, earthquake was about one second in the North-South direction, about 3.1 seconds in the East-West direction and about 1.5 seconds in the vertical direction. To confirm the existing margins in the seismic testing (i.e., shake-testing) of equipment, the licensee stated in letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), that it performed a sampling evaluation of various items of electrical equipment that were qualified by seismic testing. The licensee's sample of electrical equipment included the main station batteries, EDG battery chargers, Solidstate Controls, Inc. 15 kilovolt ampere (KVA) and 20 KVA Inverters, Cutler-Hammer Model AR420A Relays, and ABB 480 V Transformers.

The NRC staff requested the licensee to describe how seismic qualification remains valid for electrical components that are required to be qualified for seismic events. In its October 18, 2011 (Serial No. 11-5677A; Reference 10), response to the NRC staff's request, the licensee noted that the primary industry standard used for seismic qualification of new and replacement mechanical, electrical, and Instrument and Control equipment is IEEE Standard 344-1975, "Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," as endorsed by RG 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants," Revision 1. The licensee also uses 1987 version of this standard, as endorsed by RG 1.100, Revision 2.

With respect to durations and margins in testing, seismic tests are performed to simulate five OBE and one DBE events, which are generally triaxial with a typical duration of 30 seconds and minimum strong motion durations of 15 seconds for each test. Functionality of the tested equipment is verified during and after the seismic tests (i.e., shake tests).

The test response spectra in shake table testing are required to have at least 10 percent margin over the required response spectra in the entire frequency range, as required by IEEE Std. 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," as endorsed by RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," Revision 1. Based on its review of the test

response spectra data submitted by the licensee for these components, the NRC staff finds that the licensee has demonstrated that margin exists beyond the 10 percent margin that is required per IEEE Std. 323-1974.

Given (1) that the August 23, 2011, earthquake was of short duration and had low damage potential, (2) extensive plant inspections performed by both the licensee and NRC confirm a lack of damage to safety-related SSCs, (3) successful functional testing of electrical components, (4) the existence of margin in excess of that suggested by industry standards and RGs, the NRC staff has reasonable assurance that these components remain capable of performing their intended design functions during and after a potential future DBE.

Following the August 23, 2011, seismic event and the subsequent loss-of-offsite power (LOOP), all four station EDGs started and loaded onto their respective emergency buses. The SBO diesel generator also started, as designed, with the LOOP, and was subsequently successfully loaded onto the 2H emergency bus due to the 2H EDG failure, described below. All relay logic and load sequencers appeared to have worked properly during the initial event. No unexpected alarms related to the station EDGs were received at the onset of the event and the licensee did not identify any instrumentation, relay, or breaker issues that adversely impacted EDG performance during the response to the seismic event. However, approximately 50 minutes after the seismic event, the 2H EDG developed a coolant leak that required the engine to be manually secured. A diesel trouble alarm was received in the control room during this time period due to alarms at the local control panel. The licensee indicated that the coolant leakage was a result of an improperly installed gasket and not the result of the August 23, 2011, seismic event. The NRC's investigation of this event, and any subsequent regulatory actions, are described in NRC inspection report dated October 31, 2011 (Reference 30). The NRC staff considers this issue to be an inspection related item that can be resolved outside of the NRC staff's review efforts associated with the NAPS seismic event.

Following the seismic event on August 23, 2011, while the 1J EDG was supplying power to the 1J emergency bus, control room operators identified frequency oscillations on the 1J EDG bus as well as 1-III and 1-IV inverter momentary trouble alarms when the pressurizer heaters were cycled. The licensee entered this issue into its corrective action program even though the frequency oscillations appeared to remain within the technical specification frequency limits (e.g., between 59.5 and 60.5 Hz). The NRC's investigation of this event, and any subsequent regulatory actions, are described in NRC inspection report dated October 31, 2011 (Reference 30). The NRC staff considers this issue to be an inspection related item that can be resolved outside of the NRC staff's review efforts associated with the NAPS seismic event.

In its October 10, 2011, letter (Serial No. 11-566A; Reference 6), the licensee provided a list of Technical Specification Surveillance Requirements that it will complete for each EDG prior to restart. The licensee also noted that it inspected the following equipment associated with the EDGs, as well as the SBO diesel generator, in accordance with the guidance in RG 1.167: EDGs including the cabinets, relays, voltage regulators and breakers; the EDG support systems (cooling water, starting air, fuel oil, and batteries); and the SBO diesel generator engine, support systems, electrical breakers, and busses. The licensee also inspected and tested the fuel oil transfer system to verify the pumps supplied fuel oil to the EDGs as designed. The licensee did not find any seismically induced damage to the EDGs, SBO diesel generator, and the associated support systems as a result of its inspections.

The NRC staff finds that successful performance of the Technical Specification Surveillance Requirement tests will demonstrate the availability and operability of the EDGs. The NRC staff further concludes that these tests, coupled with the results of the licensee and NRC inspections (see NRC inspection report dated October 31, 2011 (Reference 30)), which did not find any seismically induced damage, provides reasonable assurance that the EDGs remain capable of performing their intended design functions during and after a potential future DBE. The NRC staff also finds that the inspection results (both by the licensee and by NRC inspectors, as detailed in inspection report dated October 31, 2011 (Reference 30)), and successful tests, demonstrate that the SBO diesel generator is capable of performing its design function.

In its October 18, 2011, letter (Serial No. 11-577A; Reference 10), the licensee stated that it inspected approximately 50 percent of the safety-related electrical vaults/duct banks and did not identify any earthquake-related damage. The NRC staff finds that the lack of finding any earthquake-related damage to the electrical vaults/duct banks provides reasonable assurance that no functional damage occurred to the SSCs.

The licensee performed external inspections of large dry transformers to ensure that no damage resulted from the seismic event. The licensee noted that it found no discoloration, damage, smell, or other problems during the inspection. The licensee also noted that it found no loosening, damage, or other problems around peripheral components such as connections, supporting insulators, and external cables. The licensee monitored voltages, temperature, noises, and did not identify any indications of damage. The licensee performed internal inspections on two safety-related dry transformers and did not identify any damage. The NRC staff finds the scope of the licensee's inspection of dry transformers to be adequate and the results demonstrate that no functional damage occurred as a result of the August 23, 2011, seismic event.

The licensee evaluated the effect of the seismic event on electrical connections. The licensee inspected a sample of electrical connections for damage. This sample included electrical connections for the Reactor Protection System (RPS), Rod Control System, and Emergency Power Buses. The licensee noted that no indications of loose or damaged connections were noted in the RPS during performance of calibrations or subsequent testing of the NAPS, Unit 2, loop A, B, and C Feedwater Control System calibrations.

In the Rod Control System, the licensee performed calibration maintenance with the Reactor Trip Breakers open. During testing, the licensee checked the connections and ensured proper seating of the logic cabinet circuit cards. The licensee also performed maintenance on the 2J Emergency Switchgear Bus (4160 V). According to the licensee, the procedure for maintenance on the 2J Emergency Switchgear Bus includes bus/cubicle inspection, insulation resistance testing, and micro-resistance readings of the bus-to-bus bolted connections and verification of proper torque of the electrical connections. The licensee further noted that other electrical tests have been performed following the seismic event that functionally tested the electrical connections. The licensee stated that there have been no reports of loose connections in any of the testing or inspections performed after the seismic event. The licensee performed internal inspections of emergency electrical and electrical power system components (e.g., breakers, process racks, etc.) and have not identified any areas of connection distress or loose components. Furthermore, the licensee's thermography program has not identified any

increase in loose connections following the seismic event. Based on this information, the NRC staff finds that the licensee has demonstrated that electrical connections have not been adversely impacted as a result of the August 23, 2011, seismic event and that no functional damage has occurred to the electrical connections as a result of the August 23, 2011, earthquake.

8.3 Electrical Systems Conclusion

Based on the above evaluation, the NRC staff concludes that the licensee has demonstrated that electrical equipment, offsite and onsite, at NAPS, Units 1 and 2, remains capable of performing their intended design functions, and that no functional damage has occurred to the electrical equipment as a result of the August 23, 2011, earthquake. The results of the NRC inspection activities also support this conclusion, in that no significant damage to electrical equipment has been observed. The NRC staff also has reasonable assurance that any degradation of equipment, whether created by the August 23, 2011, earthquake or not, should be detected during performance of routine technical specification surveillance requirements or maintenance activities. Therefore, the NRC staff finds that the resumption of plant operation will not result in undue risk to the health and safety of the public.

9.0 AUXILIARY SYSTEMS

9.1 Balance of Plant Systems

The NRC staff reviewed the licensee's submittals as they relate to the balance of plant (BOP) systems. One specific area of interest was the service water buried piping. An evaluation of buried piping, including service water, is contained in Section 3.1.3 of this safety evaluation. The remaining BOP systems are evaluated below.

9.1.1 Licensee's Assessment

By letter dated September 17, 2011 (Serial No. 11-520; Reference 1), the licensee stated that the comprehensive walkdowns, inspections, evaluations and surveillances that have been completed confirm the expected lack of significant physical or functional damage to safety-related SSCs. In addition, the surveillance and functional tests and other identified items that will be completed prior to startup will provide further assurance of the ability of safety-related and plant support SSCs to perform their design-basis functions. Further, the licensee stated that over 80 systems for Unit 1 and over 50 systems for Unit 2 have been inspected in accordance with a station procedure developed in response to this event. Results of the inspections were documented in logs, and discrepancies were entered into the Corrective Action Program. The licensee inspections did not identify any significant physical or functional damage to safety-related SSCs that would render them incapable of performing their design functions.

9.1.2 NRC Staff Evaluation

The NRC staff evaluated the information provided by the licensee to determine whether it provided assurance that the plant would continue to respond to upset conditions in a manner bounded by the safety analyses in the UFSAR for safety-related systems and systems important

to safety. The NRC staff reviewed the licensee's inspection summary and concludes that the licensee has conducted inspections consistent with the EPRI NP-6695 guidelines. The NRC staff further notes that the NRC's independent inspection, conducted by an AIT, largely confirm the licensee's inspection observations, stating in its inspection report (Reference 30), Section 8.2b, "…the team found no significant damage to the plant relating to the earthquake."

By letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), the licensee provided additional information regarding pump and valve testing for safety-related systems. Valve test results are assessed, in detail, in Section 5.4.2 of this safety evaluation. All safety-related BOP pumps have been satisfactorily tested, with the exception of the turbine-driven auxiliary feedwater (TDAFW) pump, which can only be tested after the plant is heated up. By letter dated November 3, 2011 (Serial No. 11-520C; Reference 18), the licensee indicated periodic test 1/ 2-PT-71.1Q, "Turbine Driven Feedwater Pump Test," will be performed prior to Mode 2 entry. A discussion specific to the TDAFW pump is contained in Section 3.8.2 of this safety evaluation. Further, the NRC AIT performed a review of licensee operability assessments completed since the earthquake associated with safety equipment, and no findings of significance were identified (Reference 30). Further NRC inspection activities will be conducted as described in the North Anna Power Station Post-Earthquake Restart Readiness Review Restart Readiness Inspection Plan 05000338, 339/2011011. Given the licensee inspection results, satisfactory pump and valve testing results (with the exception of the TDAFW pump), and NRC regional inspection results, the NRC staff concludes that the licensee had demonstrated that the safety-related BOP systems have not sustained functional damage that impacts operational readiness.

9.1.3 Conclusion

Based on staff review of the licensee's inspections and testing as discussed above, the NRC staff concludes that no functional damage has occurred to the BOP safety systems such that the resumption of plant operation will not result in undue risk to the health and safety of the public. The NRC staff notes that TDAFW pump testing will be performed before entry into Mode 2 and monitored as part of the reactor oversight process. The NRC staff further noted that the operability of the TDAFW pump is governed by the plant Technical Specifications.

9.2 Emergency Diesel Support Systems

EPRI-NP-6695 provides guidelines for responding to an earthquake that exceeds OBE in order to demonstrate no functional damage. Similar to other plant systems, the EDG support systems were included in the over 80 systems for Unit 1 and over 50 systems for Unit 2 have been inspected after the August 23 earthquake.

By letter dated October 10, 2011 (Serial No. 11-566A; Reference 6), in response to a RAI from the NRC staff, the licensee stated:

> Consistent with the EPRI NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake," NAPS developed a methodology for performing inspections to assess significant physical or functional earthquake-related damage to structures, systems, and components (SSCs). Using this methodology, inspections were performed on the EDGs and the Station Blackout (SBO) diesel

> generator (DG) and their support systems. The inspections did not identify any earthquake-related physical or functional damage to the EDGs, the SBO DG or their support systems that would render them incapable of performing their design functions... The following equipment associated with the EDGs, as well as the SBO DG, was inspected in accordance with the guidance noted above: EDGs including the cabinets, relays, voltage regulators and breakers; the EDG support systems (cooling water, starting air, fuel oil (FO) and batteries); the SBO DG engine, support systems, electrical breakers and busses. The FO transfer system was inspected and performance tests were run to verify the pumps supplied fuel oil to the EDGs as designed.

The NRC staff evaluated the licensee's assessment of EDG support systems, as described in the following sections.

9.2.1 Emergency Diesel Generator Fuel-Oil Storage and Transfer System

The Emergency Diesel Generator Fuel-Oil Storage and Transfer System (EDGFOST) has the following design bases:

1. Provide sufficient storage of fuel oil in missile protected, seismic category I tanks to supply the requirements for full load operation of two diesel generators for 7 days.

2. Deliver this fuel to the diesel generators by redundant, missile-protected, seismic category I systems.

The licensee UFSAR describes the EDGFOST system as each engine as having an independent 1000-gallon storage day tank with the capacity for at least 1 hour of full load operation. Each tank is located inside a seismic category I missile-protected cubicles and are filled by pumping through two buried fuel-oil lines, one of which is in standby, from two underground fuel-oil storage tanks of 50,000-gallon capacity each. The fuel lines and the underground fuel-oil storage tanks are of seismic category I design and are missile protected. The licensee provided a comprehensive listing of inspections and EDG testing by letter dated October 10, 2011.

The NRC staff reviewed the results of the EDG surveillance testing applicable to the EDGFOST system, and is satisfied that the testing described supports a no functional damage determination. Specifically, the licensee has verified that each diesel fuel oil tank has the required amount of fuel for full load operation for 7 days and the system was tested and verified to deliver fuel oil to each diesel generator. The licensee did not identify any earthquake-related physical damage to the EDG support systems. The NRC's AIT also did not identify any damage that would be considered contrary to that determination.

Based on the evaluation described above, the NRC staff concludes that no functional damage has occurred to the emergency diesel fuel-oil storage and transfer system such that the resumption of operation will not result in undue risk to the health and safety of the public.

9.2.2 Emergency Diesel Generator Cooling Water System

The emergency diesel-generator cooling water system (EDGCWS) has the following design bases:

1. Provides cooling water to the emergency diesel generator from a seismic category I, missile protected system.

2. Provides emergency diesel-generator lubricating oil cooling from a seismic Class I, missile protected system.

The licensee's UFSAR describes the EDGCWS as a system that circulates coolant through the engine at approximately 800 gpm by an engine driven centrifugal pump. The system also includes tanks, heat exchangers, valves, alarm switches, pressure and temperature gauges.

As required by the plant technical specifications, the licensee has performed surveillances that verified the following: proper starting of each diesel, achieving satisfactory standby conditions after start, achieving steady state voltage, and operating at greater than 60 minutes at full load.

The NRC staff was satisfied with the licensee's scope of review because the safety designated system was tested and verified to perform its safety function of providing cooling water to the emergency diesel generators by performing the required surveillance tests. The licensee did not identify any earthquake-related physical damage to the EDG support systems, nor did the NRC's AIT identify any damage that would be considered contrary to that determination. Therefore, based on the evaluation described above, the NRC staff concludes that no functional damage has occurred to the emergency diesel generator cooling water system such that the resumption of operation will not result in undue risk to the health and safety of the public.

9.2.3 Emergency Diesel Generator Starting Air System

The emergency diesel generator starting air system has the following design bases:

1. Start the emergency diesel generators in an average of 2 seconds.

2. Provides air pressure to the booster/accumulator piston of the diesel-generator lubrication system to initiate the operating lubrication mode.

The licensee's UFSAR describes the emergency diesel generator starting air system as including compressors, air receivers, air dryers, relief valves, dual air start solenoid valves, pressure switches and gauges. Starting system equipment located prior to the valves upstream of the air receivers such as compressor, electric motor, diesel engine, aftercoolers, air dryer and associated piping and instrumentation is considered non-safety-related.

As required by the plant technical specifications, and described in the licensee's submittal dated October 10, 2011, the licensee has verified the following: proper starting of each EDG and proper pressure in the air start receivers. The NRC staff was satisfied with the licensee's scope of review because the safety designated system was tested and verified to perform its safety function of starting the diesel generators in an average of 2 seconds by performing the required

surveillance tests. The system was also tested and verified to deliver air pressure to the booster/accumulator piston of the diesel generator lubrication system by an independent and redundant system. The licensee did not identify any earthquake-related physical damage to the EDG support systems, nor did the NRC's AIT identify any damage that would be considered contrary to that determination. Therefore, based on the evaluation described above, the NRC staff concludes that no functional damage has occurred to the emergency diesel generator starting air system such that the resumption of operation will not result in undue risk to the health and safety of the public.

9.2.4 Emergency Diesel Generator Lubrication System

The emergency diesel generator lubrication system has the following design bases:

1. Provides adequate lubrication from a seismic category I system during operation.

2. Provide continuous lubrication when the diesel generator is idle, preventing the possibility of dry starts.

The licensee's UFSAR describes the emergency generator lubrication system as consisting of engine driven lube-oil pumps, lube-oil filters, oil cooler, motor-driven lube-oil circulating pumps, electric heater, and booster/accumulator.

The licensee provided surveillance testing results which show that the EDGs were started and run at full load to demonstrate that the lubrication system is functioning properly. The NRC staff was satisfied with the licensee's scope of review because the safety designated system was tested and verified to perform its safety function of providing adequate lubrication of the emergency diesel generator by performing the required surveillance tests. The system was also tested and verified to provide continuous lubrication when the diesel generator is idle. The licensee did not identify any earthquake-related physical damage to the EDG support systems, nor did the NRC's AIT identify any damage that would be considered contrary to that determination.

Based on the evaluation described above, the NRC staff concludes that no functional damage has occurred to the emergency diesel generator lubrication system such that the resumption of operation will not result in undue risk to the health and safety of the public.

9.2.5 Emergency Diesel Generator Ventilation and Combustion Air Intake and Exhaust System

The emergency diesel generator ventilation and combustion air intake and exhaust (EDGVCAIE) system has the following design bases:

1. General space cooling from a seismic category I and missile protected system

2. Diesel-engine combustion air intake and exhaust

3. The dissipation of heat from the diesel-engine cooling system

The licensee's UFSAR describes the EDGVCAIE system as consisting of fixed-blade louver backed by a self-actuating damper, exhaust fans. The exhaust fans are not required for the operation of the diesel generators.

The licensee has provided EDG testing results which show that the EDG: achieves steady state voltage, operates greater than 60 minutes at full load, and operates greater than 24 hours. The NRC staff was satisfied with the licensee's scope of review because the safety designated system was tested and verified to perform its safety function of providing adequate general space cooling and diesel generator combustion air intake and exhaust by performing the required surveillance tests. The system was also tested and verified to dissipate heat when the diesel generator is operating.

The licensee did not identify any earthquake-related physical damage to the EDG support systems, nor did the NRC's AIT identify any damage that would be considered contrary to that determination. Based on the evaluation described above, the NRC staff concludes that no functional damage has occurred to the emergency diesel generator ventilation and combustion air intake and exhaust system such that the resumption of operation will not result in undue risk to the health and safety of the public.

9.3 Fire Protection

9.3.1 Description of Licensee Evaluation/Actions

By letter dated September 17, 2011, the licensee evaluated the impact of the August 23, 2011, seismic event on Engineering Programs at NAPS Units 1 and 2. This was accomplished through a review of procedures, regulatory documents, and industry related source documents for the Fire Protection/Appendix R Engineering Program to determine if plant equipment or supporting documentation required additional analysis or inspection in response to exceeding either the OBE, or the DBE. The licensee's assessment concluded that additional program actions were not necessary for the Fire Protection/Appendix R Engineering Program, but that additional program actions were necessary prior to Unit 1 and 2 restart for the Buried Pipe Monitoring/Ground Water Monitoring Program which included a buried pipe inspection of fire protection pipe in two areas that were previously excavated.

The licensee's September 27, 2011, letter stated that subsequent to the earthquake it was determined that procedural improvements could be incorporated to provide plant staff with more comprehensive direction for responding to an earthquake in order to verify fire main loop integrity. In that same letter, the licensee also stated that buried pipe inspections have been completed and that the inspected piping was determined to be in satisfactory condition with no indication of seismic related damage. The licensee stated that a direct inspection of the Fire Protection system piping going to the Warehouse 5 Fire Protection Pump House was conducted, that an indirect inspection for leakage by review of detailed pictures of the Fire Protection main loop near the West Security Gate was conducted within a few days following the seismic event, and that a direct inspection of Fire Protection piping to the North Anna Nuclear Information Center was also conducted.

After reviewing the information provided by the licensee in its September 17, 2011, and September 27, 2011, letters, the NRC staff requested that the licensee provide additional

information regarding fire protection systems. In a letter dated October 3, 2011, the licensee responded to the NRC staff's request for additional information and stated that consistent with the EPRI NP-6695, a methodology for performing inspections to assess significant physical or functional earthquake-related damage to SSCs was developed, and that inspections were performed on the Fire Protection System using this methodology.

The licensee's October 3, 2011, letter provided the following considerations regarding fire protection. The licensee stated that a Reasonable Assurance of Safety (RAS) evaluation was written to document the functionality of the Fire Protection System following the seismic event and the RAS evaluated aspects of the Fire Protection/Appendix R system (seismic or non-seismic) to determine reasonable assurance that the system met its functional requirements without the need for further compensatory actions. The fire pumps were checked on operator rounds and have shown no damage since the seismic activity, and surveillance tests demonstrated that the fire pumps meet their functional requirements. The Fire Protection pressure maintenance (jockey) pump has not been operating more frequently than before the earthquake, which is an indication that fire protection hydraulic piping (fire mains, fire valves, and standpipes) integrity has not been breached by the seismic event. The fire hydrants and deluge systems are dry systems and were visually checked.

The Fire Protection valves and hydrant and hose station valve positions were verified functional in accordance with station procedures. For the sprinkler systems, inspections have identified only minor deficiencies, which have been resolved through the work order process. Visual inspection of the carbon dioxide (CO2) system piping determined that there are no structural deficiencies due to the seismic event and that the main generators were purged in accordance with station procedures. The licensee further stated that this indicates that the CO2 system is available if needed for fire extinguishment. The electrical control cabinets for the CO2 system are robust in construction. In addition, a representative sample of CO2 control cabinets were inspected. Circuit boards, terminal strips, relays and internal wiring were also verified intact. The Unit 2 Main Control Room Halon System was tested and no deficiencies were noted. The licensee further stated that the emergency switchgear halon discharge nozzles were also inspected and no discrepancies noted.

The NRC staff requested further information from the licensee regarding whether or not the Unit 1 control room halon system was also tested and regarding whether or not the underfloor area is common to the entire control room (or if there is separation between the Unit 1 and Unit 2 sides). The NRC staff also asked for clarification regarding whether or not observations were made for both Units 1 and 2 emergency switchgear rooms. In a letter dated October 20, 2011, the licensee responded to the NRC staff's request for additional information and stated that there are two (2) Halon Systems in the underfloor area of the Main Control Room, System 5 (Unit 1) and System 6 (Unit 2), that are identical in layout, equipment type and design function and that Halon System 6 was tested, with no discrepancies noted. The licensee also stated that Halon control panels, halon storage bottles and system piping for both System 5 and System 6 were visually inspected and no evidence of damage attributed to the earthquake was identified. Due to the similar configuration (piping layout and design), System 5 in Unit 1 was not tested. The licensee further stated that System 5 was last tested on June 20, 2011. Based on the post-earthquake functional testing of System 6 in Unit 2, the detailed inspections of both System 5 and System 6, and the similar configurations of the two systems, the licensee concluded that there is reasonable assurance that the August 23, 2011, earthquake did not result in any

seismically-induced damage that would prevent the discharge nozzles from performing their intended function. The licensee stated that Halon System 5 and System 6 are separated by an underfloor gas suppression barrier. The licensee further stated that the Unit 1 and Unit 2 emergency switchgear room halon nozzles were visually inspected and found to be intact.

By letter dated October 3, 2011, the licensee stated that plant inspections were conducted to verify functionality of the fire doors, dampers and penetration seals in Unit 1 Containment, Units 1 and 2 Emergency Switchgear Room, Units 1 and 2 Cable Vault and Tunnel, Units 1 and 2 Cable Tray Spreading Room, Unit 2 Quench Spray, and Unit 2 Safeguards fire areas with no deficiencies found. The licensee further stated that procedures were used as a guideline for performing and documenting these inspections. The NRC staff requested clarification regarding if inspections conducted to verify functionality of the fire doors, dampers and penetration seals were conducted in Unit 2 Containment, Unit 1 Quench Spray, and Unit 1 Safeguards areas. By letter dated October 20, 2011, the licensee responded and stated that the Unit 2 Containment, Unit 1 Quench Spray and Unit 1 Safeguards were inspected and some minor deficiencies of penetration seals outside containment were identified, documented and corrected, but that the damage was not attributed to the earthquake. The licensee further stated that during inspection of the cable tray cover boards in Unit 2 Containment, several covers were determined to have been broken due to physical damage during a rigging operation and work orders were initiated for repairs. The licensee stated that several minor cracks were observed in marinite cable tray covers, which could have been caused by the earthquake since they were not identified in 2010 walkdowns, and there was no evidence of someone stepping on these particular covers. The licensee stated that a Condition Report was submitted for repairs/replacement, as required.

By letter dated October 3, 2011, the licensee stated that visual inspections of fire walls and barriers and structural steel fire coating were completed by civil engineering personnel. The results of the inspection were documented and only cosmetic damage has been found to these structures. Fire protection engineers examined several of these minor cracks and found no passage of air or light. As a result, fire barrier integrity has not been jeopardized by this cosmetic damage. The licensee stated that the work order process is being used to complete repairs to the structures, as required. The licensee stated that there have been some log entries regarding rattle space seals in the open joint between the Cable Vault floor and the Auxiliary Building mechanical penetration area below, and that the HVAC system engineer and the FP system engineer examined these seals and found them to be intact. Cable tray covers, conduit seals, conduit fire wraps, radiant energy shields, and cable tray firestops were inspected in the containments and no deficiencies were found.

The NRC staff requested clarification regarding whether or not inspections of cable tray covers, conduit seals, conduit fire wraps, radiant energy shields and cable tray firestops were conducted in other areas of the plant besides containment. By letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), the licensee responded that other areas of the plant were visually inspected for fire protection items similar to those in the containment and that passive fire protection features such as fire wrap installed on charging and component cooling pumps, and cables in the Auxiliary Building were also inspected and found to be intact. The licensee further stated that radiant energy shields are unique to the containments and are not located in other plant areas.

In the letter dated October 3, 2011, the licensee stated that the Control Room alarm panel (smoke/heat detection and fire alarms) is a Simplex network that is supervised and compliant with NFPA-72, which means that each detector is addressable through the network and constant self-checks are automatically performed by the system. According to the licensee, any loose connector base, open circuit or shorted wires will create a malfunction alarm. The licensee determined through observation, that there were no abnormal conditions with the fire detection or alarm instrumentation.

The licensee stated that immediately following the earthquake, a sprinkler head in the Unit 2 turbine building was noted to have actuated, but that no fire was present. The sprinkler was isolated and repairs were completed on August 25, 2011. The licensee further stated that approximately 10 hours after the earthquake, the Unit 2 "A" Main Transformer deluge actuated, but that no fire was noted and the system was isolated for repairs. In a letter dated November 3, 2011, the licensee reported that repairs to the Unit 2 “A” Main Transformer deluge system were completed. No other Fire Protection systems actuations were noted as a result of the earthquake.

The licensee provided an Appendix R/Fire Protection Systems Functional Validation table in its October 3, 2011, letter, which provided the method of validation for Appendix R/Fire Protection Systems. The systems included Appendix R Systems, such as emergency lighting and Appendix R instrumentation; manual systems, such as fire extinguishers and hose houses; detection systems; fire suppression systems, such as sprinkler systems, halon extinguishing systems, and standpipes; and passive fire protection, such as doors, dampers and barriers. The licensee described the methods of functional validation, which included visual inspections, functional checks, alarm panel checks, and piping integrity checks.

The licensee further stated that based on performance monitoring of the Fire Protection System since the seismic activity, it has been concluded that the Fire Protection Instrumentation, Suppression System, Detection System, and Passive Fire Protection Barriers are capable of performing their design functions. The licensee stated that its Engineering Department performed thorough inspections of the Fire Protection System to support this determination and that the guidance of Fire Protection/Appendix R implementing procedures, applicable periodic tests (PTs), periodic maintenance procedures and TRM requirements, were used to determine functionality acceptance during the inspections and other evaluations. The licensee further stated that inspections did not identify any significant physical or functional damage to the system that would render it incapable of performing its design functions. The NRC staff requested the licensee clarify that its assertions regarding system functionality are based on performance since August 23, 2011. Specifically the NRC staff asked whether it was the August 23, 2011, earthquake, or subsequent seismic activity that occurred after August 23, 2011.

By letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), the licensee stated that the statements regarding the seismic activity refer to the earthquake of August 23, 2011, and that their conclusion bounds subsequent after-shocks since August 23, 2011, to the present, since the magnitudes of the follow-on events were less than the initial event.

The NRC staff requested that the licensee provide verification that smaller diameter fire protection pipes and dead legs were checked for clogging and that fire mains were flushed as

described in EPRI NP-6695, Table 5-1. By letter dated October 20, 2011 (Serial No. 11-566C; Reference 12), the licensee stated that the fire main was flushed on September 23, 2011, and that the flush flows water in one direction in each plant area using selected hydrants with a quantity of outlets that provide sufficient flow rates for flushing. The licensee further stated that this method enhances the possibility of removing any objects and sediments that may be in the system, and that each plant area was flushed for 15 minutes. The licensee further stated that discharge from the fire main was clear and free of sediment or corrosion products in each plant area and that based on clarity of the fire main water discharge, it was not necessary to flush the smaller diameter piping associated with sprinkler and deluge systems.

9.3.2 NRC Staff Evaluation of Licensee Evaluation/Actions

The NRC staff reviewed the information provided by the licensee and determined that it satisfied the criteria related to fire protection outlined in EPRI Technical Report NP-6695. Specifically, the information provided by the licensee addressed the following EPRI NP-6695 guidance:

1. Section 4.3.1- control room board checks for trips to systems and equipment including fire protection main leakage;

2. Section 5.3.2.1 - post earthquake inspections of pumps and fire protection system mains;

3. Table 5-1 - visual inspection of fire deluge systems protecting transformers;

4. Table 5-1 - inspection for self excavation and actuation of back up fire pumps for buried pipe; and

5. Table 5-1 - inspection for corrosion and growths which are knocked loose by earthquake motion and can clog small diameter pipes.

The NRC staff noted that the licensee evaluated the Fire Protection/Appendix R Engineering Program, completed a Reasonable Assurance of Safety for the Fire Protection Systems, and conducted inspections and tests on the fire pumps, fire mains, fire valves, standpipes, sprinkler systems, the carbon dioxide system, the halon systems, fire doors, fire dampers, penetration seals, fire walls and barriers, structural steel fire coating, cable tray covers, conduit seals, conduit fire wraps, radiant energy shields, cable tray firestops, and fire detection and alarm systems. These SSCs were identified as intact by the licensee, in good material condition, with no indication of earthquake-related degradation. The NRC staff noted that the licensee identified minor deficiencies for the sprinkler systems , which included some marinate cable tray covers, whereby the licensee stated were, or will be, resolved through the work order process. The NRC staff agrees that the licensee's work order process is the proper mechanism to disposition these deficiencies.

9.3.3 Conclusion

Based on the information provided by the licensee, the NRC staff has determined that the licensee has adequately verified the functionality, following the earthquake, of the fire protection SSCs, both passive and active, that are credited in its approved fire protection program or are

relied upon to ensure safe shutdown in the event of a fire. In addition, the NRC staff concluded that the licensee has adequately demonstrated that, consistent with EPRI topical report NP-6695, no functional damage has occurred to the fire protection systems as a result of the August 23, 2011, earthquake.

10.0 RISK INSIGHTS

10.1 Description of Licensee Evaluations/Actions

The NRC staff was concerned that non-safety-related equipment credited in a risk-informed license amendment, could have been affected by the August 23, 2011, seismic event. The NRC staff requested information about the licensee's approach to address this equipment.

In its letter dated October 3, 2011 (Serial No. 11-566; Reference 4), the licensee stated that risk-informed license amendments were reviewed to determine whether credit was previously given for non-safety-related equipment to support the risk informed amendments. The licensee determined that an amendment crediting the station blackout (SBO) diesel was the only risk-informed amendment for which non-safety-related equipment was credited in the risk assessment.

The licensee stated that during the August 23, 2011, earthquake, the SBO diesel started and was subsequently used to provide power to an emergency bus for several hours. Since then the SBO diesel has been visually inspected, including the engine, motor control centers, and related bus work. The SBO diesel is considered fully functional.

10.2 NRC Staff's Evaluation of Licensee Evaluation/Actions

The NRC staff reviewed the licensee's response to the NRC staff's question regarding the functionality of non-safety-related equipment credited in risk-informed license amendments and finds that the licensee's response is acceptable, based on the licensee having reviewed risk-informed amendments and determining that the SBO diesel was the only non-safety-related equipment credited. The SBO diesel's performance following the seismic event and the inspections performed by the licensee confirm that the equipment is fully functional.

Based on the licensee's review for non-safety-related equipment credited in a risk-informed license amendments, and the performance and inspection results of the SBO diesel described above, the NRC staff finds that there is reasonable assurance that no functional damage has occurred to those features necessary to ensure continued operation without undue risk to the health and safety of the public.

11.0 CONCLUSION

Based on the above evaluations, the NRC concludes that the licensee has acceptably demonstrated that no functional damage has occurred at NAPS to those features necessary for continued operation, and that NAPS Units 1 and 2, can be operated without undue risk to the health and safety of the public.

12.0 REFERENCES

1. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, North Anna Independent Spent Fuel Storage Installation Summary Report of August 23, 2011, earthquake Response and Restart Readiness Determination Plan," Serial No. 11-520, dated September 17, 2011 (ADAMS Accession No. ML11262A151).

2. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Post-Earthquake Restart Readiness Determination Plan Status Update," Serial No. 11-520A, dated September 27, 2011 (ADAMS Accession No. ML11272A129).

3. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan," Serial No. 11-544, dated September 27, 2011 (ADAMS Accession No. ML11272A130).

4. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information Regarding the August 23, 2011, earthquake - Restart Readiness Determination Plan," Serial No. 11-566, dated October 3, 2011 (ADAMS Accession No. ML11277A267).

5. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan," Serial No. 11-544A, dated October 3, 2011 (ADAMS Accession No. ML11277A270).

6. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan," Serial No. 11-566A, dated October 10, 2011 (ADAMS Accession No. ML11286A018).

7. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information, Restart Readiness Determination Plan," Serial No. 11-577, dated October 10, 2011 (ADAMS Accession No. ML11286A019).

8. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Toot Cause Evaluation, Dual Unit Trip Following the August 23, 2011, earthquake,” Serial No. 11-578, dated October 12, 2011 (ADAMS Accession No. ML11290A170).

9. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan,” Serial No. 11-544B, dated October 17, 2011 (ADAMS Accession No. ML11292A034).

10. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, North Anna Independent Spent Fuel Storage Installation, Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan,” Serial No. 11-577A, dated October 18, 2011 (ADAMS Accession No. ML11292A151).

11. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information, Restart Readiness Determination Plan,” Serial No. 11-566B, dated October 18, 2011 (ADAMS Accession No. ML11292A198).

12. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information (RAI), Status of Near Term Action Items, Restart Readiness Determination Plan,” Serial No. 11-566C, dated October 20, 2011 (ADAMS Accession No. ML11297A122).

13. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Request for Additional Information Regarding the Earthquake on August 23, 2011 and Restart Readiness Determination Plan,” Serial No. 11-544C, dated October 25, 2011 (*not publicly available – proprietary information*).

14. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information (RAI), Restart Readiness Determination Plan,” Serial No. 11-566D, dated October 28, 2011 (ADAMS Accession No. ML11305A090).

15. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Request for Additional Information (RAI), Long-Term Questions - Restart Readiness Determination Plan,” Serial No. 11-577B, dated October 28, 2011 (ADAMS Accession No. ML11305A091).

16. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Independent Spent Fuel Storage Installation, Determination Of Restart Readiness and Long-Term Action Plan to be Completed after Unit Restart," Serial No. 11-520B, dated October 31, 2011 (ADAMS Accession No. ML11307A229).

17. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Response to Requests for Additional Information (RAI), Restart Readiness Determination Plan," Serial No. 11-566E, dated October 31, 2011 (ADAMS Accession No. ML11307A228).

18. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Revised Independent Spent Fuel Storage Installation, Restart Readiness Determination Plan – Completed Activities, Long-Term Action Plan to Be Completed After Restart," Serial No. 11-520C, dated November 3, 2011 (ADAMS Accession No. ML11308B386).

19. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Revised Response to Request for Additional Information (RAI), Long-Term Actions to Address Seismic Analysis Considering the August 23, 2011, earthquake," Serial No. 11-577C, dated November 4, 2011 (ADAMS Accession No. ML11312A243).

20. Grecheck, E. S., Virginia Electric and Power Company (Dominion), letter to U.S. Nuclear Regulatory Commission, "Virginia Electric and Power Company (Dominion), North Anna Power Station Units 1 and 2, Independent Spent Fuel Storage Installation, Revised Long-Term Actions Commitment List," Serial No. 11-520D, dated November 7, 2011 (ADAMS Accession No. ML11314A069).

21. McCree, V. M., U.S. Nuclear Regulatory Commission, letter to David Heacock, Virginia Electric and Power Company, "Confirmatory Action Letter – North Anna Power Station Unit Nos. 1 And 2, Commitments To Address Exceeding Design Bases Seismic Event (TAC Nos. ME7050 and ME7051)," CAL No. 2-2011-001, dated September 30, 2011 (ADAMS Accession No. ML11273A078).

22. Virginia Electric and Power Company (Dominion), licensee slides entitled, "Overview of 08/23/11 Earthquake Response and Restart Readiness Demonstration Plan, North Anna Power Station Units 1 and 2," dated September 8, 2011 (ADAMS Accession No. ML11252A006).

23. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.167, “Restart of a Nuclear Power Plant Shut Down by a Seismic Event,” March 1997 (ADAMS Accession No. ML003740093), and the associated Electric Power Research Institute (EPRI) report, NP-6695, “Guidelines for Nuclear Plant Response to an Earthquake,” available from the epri.com website.

24. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.166, “Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Post-Earthquake Actions,” March 1997 (ADAMS Accession No. ML003740089).

25. U.S. Nuclear Regulatory Commission, Generic Letter 88-20, Supplement 4, “Individual Plant Examination of External Events (IPEEE), Accident Vulnerabilities – 10 CFR 50.54(f),” dated June 28, 1991 (ADAMS Accession No. ML031150485).

26. Monarque, U.S. Nuclear Regulatory Commission, letter to David A. Christian, Virginia Electric and Power Company, “North Anna Power station, Units 1 and 2 – Review of Individual Plant Examination of External Events (IPEEE) (TAC Nos. M83647 and M83648),” dated June 5, 2000.

27. U.S. Nuclear Regulatory Commission, Regulatory Issue Summary (RIS) 2005-20, Revision 1, “Revision to NRC Inspection Manual Part 9900 Technical Guidance, “Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety”,” on April 16, 2008 (ADAMS Accession No. ML073440103).

28. U.S. Nuclear Regulatory Commission, NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification,” dated December 20, 1988 (ADAMS Accession No. ML031220290).

29. U.S. Nuclear Regulatory Commission, NRC Generic Letter 82-07, “Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46,” dated February 19, 1987 (ADAMS Accession No. ML031150371).

30. McCree, V. M., U.S. Nuclear Regulatory Commission, letter to David A. Heacock, Virginia Electric and Power Company, “North Anna Power Station – Augmented Inspection Team (AIT) Report 05000338/2011011, 05000339/2011011, 07200016/2011001, and 07200056/2011002,” dated October 31, 2011 (ADAMS Accession No. ML113040031).

31. Martin, R. E., U.S. Nuclear Regulatory Commission, letter to David A. Heacock, Virginia Electric and Power Company, “North Anna Power Station, Unit Nos. 1 and 2, Request for Information Regarding the Earthquake of August 23, 2011 (TAC Nos. ME7050 and ME7051),” dated September 14, 2011 (ADAMS Accession No. ML11258A021).

32. Electric Power Research Institute, “EPRI Materials Reliability Program (MRP) 227, ‘Pressurized Water Reactor Internals Inspections and Evaluation Guidelines’,” December 2008 (*not publicly available - proprietary*).

33. U.S. Nuclear Regulatory Commission, Information Notice (IN) 83-38, "Defective Heat Sink Adhesive and Seismically Induced Chatter In Relays Within Printed Circuit Cards," dated June 13, 1983 (ADAMS Legacy Accession No. 8305110470; also available at http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/1983/).

34. U.S. Nuclear Regulatory Commission, RG 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants," Revision 1, August 1977.

35. U.S. Nuclear Regulatory Commission, RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," Revision 1, June 1984.

36. U.S. Nuclear Regulatory Commission, Mendiola, A. J., memorandum to William H. Ruland, "Technical Audit Report of North Anna Post-Seismic Fuel Inspections," October 4, 2011 (not publicly available – proprietary).

Principal Contributors: P. Bamford, G. Bedi, J. Bettle, J. Billerbeck, P. Boyle, G. Casto, G. Cheruvenki, P. Clifford, C. Fairbanks, F. Farzam, M. Franke, D. Frumkin, S. Gardocki, C. Gratton, O. Hopkins, W. Jessup, K. Karwoski, B. Lee, Y. Li, G. McCoy, M. Orenak, K. Manoly, R. Martin, M. McConnell, A. Mendiola, S. Miranda, E. Murphy, B. Parks, G. Purciarello, D. Rahn, J. Robinson, A. Sabisch, M. Snodderly, J. Tsao, A. Tsirigotis, G. Wilson, and R. Wolfgang

Date: November 11, 2011