VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

October 28, 2011

10 CFR 100, Appendix A

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

| | |
|---|---|
| Serial No.: | 11-566D |
| NL&OS/ETS | R0 |
| Docket Nos.: | 50-338 |
| | 50-339 |
| License Nos.: | NPF-4 |
| | NPF-7 |

**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**

By letters dated September 26, 28, and 30, and October 6 and 13, 2011, the NRC requested additional information regarding Dominion's Restart Readiness Determination Plan for North Anna Power Station following the August 23, 2011 Central Virginia earthquake. By letters dated September 27, 2011 (Serial No. 11-544), October 3, 2011 (Serial Nos. 11-544A and 11-566), October 10, 2011 (Serial Nos. 11-566A and 11-577), October 17, 2011 (Serial No. 11-544B), October 18, 2011 (Serial Nos. 11-566B and 11-577A), and October 20, 2011 (Serial No. 11-566C), Dominion provided responses to numerous RAIs. Upon reviewing Dominion's responses and as a result of several follow-up conference calls, the NRC has asked for additional information to support the review. Therefore, Dominion is providing responses to recent NRC questions/clarifications in the attachment to this letter. The specific technical review areas and the associated questions being answered are provided below for reference:

| | |
|---|---|
| Electrical & I&C | Clarifications 1 and 2 |
| Inservice Testing | Clarifications 1, 2, 3, 4, and 5 |
| Steam Generators | Clarification 1 |
| Piping | Clarifications 1, 2, and 3 |
| Reactor Vessel Internals | Question 1a through 1e |

A001
NRR

If you have any questions or require additional information, please contact Thomas Shaub at (804) 273-2763 or Gary D. Miller at (804) 273-2771.

Sincerely,

E. S. Grecheck
Vice President – Nuclear Development

Attachment:

Response to Request for Additional Information - Restart Readiness Determination Plan

There are no commitments made in this letter.

VICKI L. HULL
Notary Public
Commonwealth of Virginia
140542
My Commission Expires May 31, 2014

COMMONWEALTH OF VIRGINIA )

COUNTY OF HENRICO )

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by E. S. Grecheck who is Vice President – Nuclear Development, of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 28TH day of October, 2011.

My Commission Expires: May 31, 2014.

Vicki L. Hull
Notary Public

cc: U.S. Nuclear Regulatory Commission - Region II
Marquis One Tower
245 Peachtree Center Ave., NE
Suite 1200
Atlanta, Georgia 30303-1257

NRC Senior Resident Inspector
North Anna Power Station

M. Khanna
NRC Branch Chief – Mechanical and Civil Engineering
U. S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 08 G-9E3
11555 Rockville Pike
Rockville, MD 20852-2738

R. E. Martin
NRC Project Manager
U. S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 08 G-9A
11555 Rockville Pike
Rockville, MD 20852-2738

P. G. Boyle
NRC Project Manager
U. S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 08 G-9A
11555 Rockville Pike
Rockville, MD 20852-2738

J. E. Reasor, Jr.
Old Dominion Electric Cooperative
Innsbrook Corporate Center
4201 Dominion Blvd.
Suite 300
Glen Allen, Virginia 23060

**Attachment**

**Response to Request for Additional Information**
**Restart Readiness Determination Plan**

**Virginia Electric and Power Company**
**(Dominion)**
**North Anna Power Station Units 1 and 2**

## BACKGROUND

By letters dated September 26, 28, and 30, and October 6 and 13, 2011, the NRC requested additional information regarding Dominion's Restart Readiness Determination Plan for North Anna Power Station following the August 23, 2011 Central Virginia earthquake. By letters dated September 27, 2011 (11-544), October 3, 2011 (Serial Nos. 11-544A and 11-566), October 10, 2011 (Serial Nos. 11-566A and 11-577), October 17, 2011 (Serial No. 11-544B), October 18, 2011 (Serial Nos. 11-566B and 11-577A), and October 20, 2011 (Serial No. 11-566C), Dominion provided numerous responses to the RAIs. Upon reviewing Dominion's responses and as a result of several follow-up conference calls, the NRC has asked for additional information to support their review activities. Therefore, Dominion is providing responses to recent remaining NRC questions/clarifications below.

## *NRC Request for Information*

*Electrical and I&C*

1. *Provide a list of the Units 1 and 2 Periodic Tests (PTs) that were/will be performed for electrical and I&C equipment, and summarize the individual PT's scope and test results.*

## Dominion Response

The Unit 1 Technical Specification (TS) surveillance tests (PTs) identified below were completed subsequent to the August 23, 2011 earthquake to establish operability of the nuclear steam supply system (NSSS) protection circuits. The similar Unit 2 PTs have been completed with the exception of three PTs. The three (3) PTs are on the Unit 2 Mode hold list and will be completed prior to entering Mode 4.

Instrument CHANNEL CALIBRATIONS [Instrument Calibration Procedures (ICPs)], CHANNEL OPERATIONAL TESTS (COT), and TRIP ACTUATING DEVICE OPERATIONAL TESTS (TADOT) have been completed for the Reactor Trip System (RTS) and the Engineered Safety Features Actuation System (ESFAS) functions listed below. These tests were completed in accordance with the surveillance requirements noted. ICP performance 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. The functional test of protection system bistables (i.e., analog comparator "NAL" Cards) is embedded in the Instrument Calibration Procedure.

North Anna transmitter calibrations are performed using quality controlled gauges and pressure devices. In cases where the transmitter is a differential pressure transmitter, a wet calibration rig is typically used to keep the transmitter filled and vented during the calibration.

Functional testing (which validates proper logic, relay, and component actuation) of the RTS and ESFAS was completed subsequent to the August 23, 2011 earthquake using the following procedures:

| | |
|---|---|
| 1-PT-36.1A/B: | Train A/B Reactor Protection and ESF Logic Actuation Logic Test |
| 1-PT-57.4: | Safety Injection Operational Test |
| 1-PT-66.3: | Containment Depressurization Actuation Operational Test |
| 1-PT-71.4: | AFW Pump Time Response and Logic Test Including Service Water Pump AND SBO Diesel Auto Start Tests on U1 Loss of Reserve Power |

The following surveillances were performed subsequent to the August 23, 2011 earthquake on the Reactor Trip System (RTS) and Engineered Safety Features Actuation System (ESFAS) instrumentation.

TS 3.3.1: RTS Instrumentation

1. $\Delta T/T_{AVG}$ Protection System – Table 3.3.1-1 #6 and 7
   SR 3.3.1.7 COT procedures: 1-PT-31.1.1, 31.1.2, 31.1.3
   SR 3.3.1.12 calibration procedures: 1-PT-31.2.1, 31.2.2, 31.2.3
2. Pressurizer Pressure Protection – Table 3.3.1-1 #8
   SR 3.3.1.7 COT procedures: 1-PT-31.5.1, 31.5.2, 31.5.3
   SR 3.3.1.10 calibration procedures: 1-PT-31.6.1, 31.6.2, 31.6.3
3. Pressurizer Level Protection – Table 3.3.1-1 #9
   SR 3.3.1.7 COT procedures: 1-PT-31.7.1, 31.7.2, 31.7.3
   SR 3.3.1.10 calibration procedures: 1-PT-31.8.1, 31.8.2, 31.8.3
4. Steam Flow and Feed Flow Protection – Table 3.3.1-1 #15
   SR 3.3.1.7 COT procedures: 1-PT-32.3.1, 32.3.2, 32.3.3, 32.3.4, 32.3.5, 32.3.6
   SR 3.3.1.10 calibration procedures: 1-PT-32.4.1, 32.4.2, 32.4.3, 32.4.4, 32.4.5, 32.4.6
5. Turbine First Stage Pressure Protection – Table 3.3.1-1 #18
   SR 3.3.1.10 calibration procedures: 1-PT-32.4.7, 32.4.8
6. Reactor Coolant Flow Protection – Table 3.3.1-1 #10
   SR 3.3.1.7 COT procedures: 1-PT-31.3.1, 31.3.2, 31.3.3, 31.3.4, 31.3.5, 31.3.6, 31.3.7, 31.3.8, 31.3.9
   SR 3.3.1.10 calibration procedures: 1-PT-31.4.1, 31.4.2, 31.4.3, 31.4.4, 31.4.5, 31.4.6, 31.4.7, 31.4.8, 31.4.9
7. Steam Generator Narrow Range Level Protection – Table 3.3.1-1 #14 and 15
   SR 3.3.1.7 COT procedures: 1-PT- 32.1.1, 32.1.2, 32.1.3, 32.1.4, 32.1.5, 32.1.6, 32.1.7, 32.1.8, 32.1.9; 1-PT-32.3.1, 32.3.2, 32.3.3, 32.3.4, 32.3.5, 32.3.6
   SR 3.3.1.10 calibration procedures: 1-PT-32.2.1, 32.2.2, 32.2.3, 32.2.4, 32.2.5, 32.2.6, 32.2.7, 32.2.8, 32.2.9; 1-PT-32.4.1, 32.4.2, 32.4.3, 32.4.4, 32.4.5, 32.4.6
8. Nuclear Instrumentation (NI) Source Range Protection – Table 3.3.1-1 #5
   SR 3.3.1.7 COT procedure: 1-PT-30.5
   SR 3.3.1.11 calibration procedures: 1-PT-30.4.1, 30.4.2

TS 3.3.1: Reactor Trip System (RTS) Instrumentation (continued)

9. Nuclear Instrumentation (NI) Intermediate Range Protection – Table 3.3.1-1 #4
   SR 3.3.1.11 calibration procedures: 1-PT-30.4.3, 30.4.4
10. Nuclear Instrumentation (NI) Power Range Protection – Table 3.3.1-1 #2,3, and 18
   SR 3.3.1.7 COT procedure: 1-PT-30.2.1, 30.2.2, 30.2.3, 30.2.4
   SR 3.3.1.8 COT procedures: 1-PT-30.7.1, 30.7.2, 30.7.3, 30.7.4
   SR 3.3.1.11 calibration procedures: 1-PT-30.3.2.1, 30.3.2.2, 30.3.2.3, 30.3.2.4
11. Safety Injection Input from ESFAS: Table 3.3.1-1 #17
   SR 3.3.1.14 TADOT procedure: 1-PT-57.4
12. Reactor Trip Breakers: Table 3.3.1-1 #1,19,20,21
   SR 3.3.1.14 TADOT procedure: 1-PT-36.6
   SR 3.3.1.4 TADOT and SR 3.3.1.5 Actuation Logic Test procedures: 1-PT-36.1A, 36.1B
13. Reactor Coolant Pump Breaker Position: Table 3.3.1-1 #11
   SR 3.3.1.14 TADOT procedure: 1-PT-33.5
14. Reactor Coolant Pump UV/UF – Table 3.3.1-1 #12 and 13
   SR 3.3.1.10 calibration procedures: 1-PT-33.2A, 33.2B, 33.2C, 33.4A, 33.4B, 33.4C
15. Turbine Trip Stop Valve Closure – Table 3.3.1-1 #16
   SR 3.3.1.10 calibration procedure: 1-PT-31.9.5
16. Turbine Trip Auto Stop Oil Pressure Switches – Table 3.3.1-1 #16
   SR 3.3.1.10 calibration procedures: 1-PT-31.9.2, 31.9.3, 31.9.4

ESFAS Instrumentation

1. Containment Pressure Protection – Table 3.3.2-1 #1,2,3, and 4
   SR 3.3.2.4 COT procedures: 1-PT-35.1.1, 35.1.2, 35.1.3, 35.1.4
   SR 3.3.2.8 calibration procedures: 1-PT-35.2.1, 35.2.2, 35.2.3, 35.2.4
2. Pressurizer Pressure Protection – Table 3.3.2-1 #1,8
   SR 3.3.2.4 COT procedures: 1-PT-31.5.1, 31.5.2, 31.5.3
   SR 3.3.2.8 calibration procedures: 1-PT-31.6.1, 31.6.2, 31.6.3
3. Main Steam Line Pressure Protection – Table 3.3.2-1 #1 and 4
   SR 3.3.2.4 COT procedures: 1-PT-32.5.1, 32.5.2, 32.5.3
   SR 3.3.2.8 calibration procedures: 1-PT-32.6.1, 32.6.2, 32.6.3, 32.6.4, 32.6.5, 32.6.6, 32.6.7, 32.6.8, 32.6.9
4. Main Steam Line Flow Protection – Table 3.3.2-1 #1 and 4
   SR 3.3.2.4 COT procedures: 1-PT-32.3.1, 32.3.2, 32.3.3, 32.3.4, 32.3.5, 32.3.6
   SR 3.3.2.8 calibration procedures: 1-PT-32.4.1, 32.4.2, 32.4.3, 32.4.4, 32.4.5, 32.4.6
5. $\Delta$ T/$T_{AVG}$ Protection – Table 3.3.2-1 #1,4, and 8
   SR 3.3.2.4 COT procedures: 1-PT-31.1.1, 31.1.2, 31.1.3
   SR 3.3.2.8 calibration procedures: 1-PT-31.2.1, 31.2.2, 31.2.3

ESFAS Instrumentation (continued)

6. Refueling Water Storage Tank Level Protection – Table 3.3.2-1 #2, and 7
   SR 3.3.2.4 COT procedures: 1-PT-45.1.1, 45.1.2, 45.1.3, 45.1.4
   SR 3.3.2.8 calibration procedures: 1-PT-44.2.5, 44.2.6, 44.2.7, 44.2.8
7. Steam Generator Narrow Range Level Protection – Table 3.3.2-1 #5, and 6
   SR 3.3.2.4 COT procedures: 1-PT-32.1.1, 32.1.2, 32.1.3, 32.1.4, 32.1.5, 32.1.6, 32.1.7, 32.1.8, 32.1.9
   SR 3.3.2.8 calibration procedures: 1-PT-32.2.1, 32.2.2, 32.2.3, 32.2.4, 32.2.5, 32.2.6, 32.2.7, 32.2.8, 32.2.9
8. ESFAS automatic actuation logic and relays – Table 3.3.2-1 #1,2,3,4,5,6, and 7
   SR 3.3.2.2 Actuation Logic Test and SR 3.3.2.3 Master Relay Test procedures: 1-PT-36.1A, 36.1B
   SR 3.3.2.5 Slave Relay Test and SR 3.3.2.7 Manual Initiation (SI/CDA/Phase A/Phase B) procedures: 1-PT-57.4, 66.3
9. Auxiliary Feedwater Initiation – Table 3.3.2-1 #6
   SR 3.3.2.4 COT and SR 3.3.2.6 and 3.3.2.7 TADOT procedure: 1-PT-71.4

Control and Balance of Plant

The following calibration procedures were completed, unless otherwise noted, for the instrumentation listed below on Unit 2. Calibration techniques are similar to those used for the RTS/ESFAS instruments. Similar procedures were used to complete the calibrations for Unit 1 control and balance of plant systems noted in our previous response (Serial No. 11-566):

10. Steam Generator Level Control 2-ICP-FW-F-2478/2488/2498
11. Pressurizer Pressure Control 2-PT-44.2.17 and 2-PT-41.2.11
12. Pressurizer Level Control 2-PT-34.8.1
13. Steam Dump Control calibration procedure: ICP-P-2-T-408
14. $T_{ave}$ Steam Dump control calibration procedure: ICP-P-2-T-409B
15. $T_{AVG}$ Rod Control and Power Mismatch
16. Power Mismatch / Rod speed control calibration procedure: ICP-P-2-T-409B
17. Power Mismatch calibration procedure: 2-ICP-RC-T-2409D
18. Feedwater Bypass Flow Control 2-ICP-FW-F-2479/2489/2499
19. Steam Generator Atmospheric Relief Valve Control 2-ICP-MS-P-201A/B/C
20. $T_{AVG}$ Deviation Alarm and Median Select Circuits 2-ICP-RC-T-2408A
21. Refueling Water Storage Tank (RWST) 2-PT-44.2.5, 44.2.6, 44.2.7, 44.2.8
22. Emergency Condensate Storage Tank (ECST) 2-PT-41.2.5A, PT-41.2.5B
23. Casing Cooling tank level: 2-PT-45.2.2, 45.2.4
24. Volume Control Tank (VCT) ICP-P-2-L-112/115
25. Chemical Addition Tank (CAT) 2-ICP-QS-L-201

26. Steam Generator (S/G) wide range (WR) level 2-PT-41.4, 41.5, 41.6
27. Pressurizer (PZR) WR Level 2-ICP-RC-L-2462
28. Reactor Vessel Level Indication System (RVLIS) 2-PT-44.2.18
29. Inadequate Core Cooling Monitor (ICCM) 2-PT-44.2.46, 44.2.47
30. RCS WR Pressure – NDT2-PT-44.2.3, 44.2.4, 44.3
31. RHR Flow 2-ICP-RH-F-2605
32. Safety Injection Flow 2-ICP-SI-F-2960/61/62/63/2932/2933/2940/2940-1
33. Steam Line Radiation Monitors / Noble Gas Effluent Monitor 2-PT-44.2.36/37/38
34. Containment Radiation Monitor 2-PT-38.2.1.19/20,
35. N-16 Leak Rate Radiation Monitor 2-PT-46.4.5,6,7,8 (currently in progress)
36. Condenser Air Ejector Radiation Monitor 2-PT-38.2.1.14
37. ATWS mitigation system actuation circuitry (AMSAC) functional testing completed under 2-PT-36R
38. FW Flow ultrasonic flow monitors (UFMs) 2-PT-32.4.9/10 (complete except for that to be done at full power)

2. *Provide the results of Dominion's investigation of the 1J EDG frequency oscillations that occurred following the earthquake.*

**Dominion Response**

While the 1J emergency diesel generator (EDG) was supplying the 1J emergency bus following the August 23, 2011 earthquake, cycling of the pressurizer heaters caused EDG frequency to vary between 59.7 Hz - 60 Hz producing inverter trouble alarms. The EDG remained fully operable, but a troubleshooting effort was initiated to reduce potential alarms being received in the control room.

A previous frequency oscillation with the 1J EDG that was identified on strip charts recorded during an isochronous run on September 24, 2010. A drop in frequency of 0.3 Hz with some instability was noted. However, overall EDG performance was within the Technical Specification acceptance criterion and the surveillance was completed satisfactorily at that time. Based on the previous occasion of frequency oscillation, Dominion concluded that the frequency oscillations seen on August 23, 2011 were likely preexistent and not caused by the earthquake.

However, due to the recurrence of the frequency oscillation issue, the decision was made to change the mechanical governor and the motor-operated potentiometer (MOP). Following replacement of the mechanical governor and the MOP, the EDG was tuned and it was confirmed through additional testing that the EDG frequency was maintained between $\pm$ 0.1 Hz, which is within the TS acceptance criteria of $\pm$ 0.5 Hz.

_Inservice Testing (IST)_

Inservice Testing questions received in E-mails dated October 24 and 25, 2011.

1. *It was stated that "Safety related pumps and valves were inspected as part of the system inspections." Were all safety related pumps and valves in both units inspected?*

**Dominion Response**

Each safety related pump and valve on both units was inspected as part of the structure, system, and components detailed inspections preformed post earthquake. In addition, with the exception of the inside recirculation spray (IRS) pumps on Unit 1, the safety related pumps on both units were or will be tested in accordance with the Inservice Testing Program. The auxiliary feedwater turbine driven pumps will be tested during startup when there is sufficient steam pressure to test the pump.

2. *Why weren't the Unit 1 Inside Recirculation Spray pumps tested?*

**Dominion Response**

The IRS pumps are located in the basement of containment. Testing these pumps is an involved process. The test 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. After installing instrumentation and blanks, and rotating the pump discharge pipe elbows to the recirculation loop, the dike is filled and the pumps started and run one at a time to obtain the required pump characteristics. Flow, pressure, vibration, and motor amps data are obtained from each pump. After running the pumps, the dike is drained and disassembled, instrumentation is removed, blanks are removed, strainer header spool pieces and test inlet covers are re-installed, and the pump discharge pipe elbows are rotated back.

The Unit 2 IRS pumps were tested as described above with acceptable results. In addition to testing the Unit 2 IRS pumps, the Unit 1 and Unit 2 IRS pumps were inspected during the structure, systems and components (SSCs) detailed inspection. Based on the detailed inspections on both pumps and satisfactory Unit 2 testing results, the ruggedness of the pump design, and similar orientation of the pumps in containment basements, the Unit 1 IRS pumps were judged to be acceptable without performing functional testing.

3. *Were the component cooling water pumps and SG blowdown containment isolation valves (mentioned in your 9/17 letter) inspected and tested?*

**Dominion Response**

The component cooling water pumps were tested in accordance with the IST Program and the steam generator (S/G) blowdown valves were stroke time tested in accordance with the IST Program. These components test results were satisfactory.

4. *Dominion's letter dated October 3, 2011 (Serial No. 11-566), details testing done on Unit 1 valves and lists three valves that did not pass their stroke time. Those valves were repaired. Please provide the root cause for these stroke time failures. If these root cause was damage from the earthquake, please state if other similar valves were thoroughly inspected. If the root cause was not from the earthquake, please describe the cause, corrective action, and the additional corrective actions being taken to prevent future stroke time failures.*

**Dominion Response**

1-CC-TV-102A containment isolation valve for CC return from B reactor coolant pump (RCP)

This valve stroke time was slightly greater than the IST Program acceptance criteria, but was well within the containment isolation design requirements. A cause analysis determined that the limit switch was not making up until the last 1 or 2 degrees of valve travel. When this soft seat butterfly valve's limit is set too close to the end of rotation, it is difficult to obtain consistent stroke time results. Leak tightness is achieved before full travel into the soft seat. The limit switch was adjusted in accordance with North Anna maintenance procedures and the stroke time returned to the acceptable band. There is no indication that the limit switch adjustment concern was related to the August 23, 2011 earthquake. (CA 211060)

1-MS-TV-101A/101B Main Steam Trip Valves (MSTVs)

The MSTVs are provided to isolate the S/G in the event of a steam line rupture downstream of the trip valve. The valve is essentially a swing-disc check valve installed so when the disc is seated, pressure from the S/G holds the disc shut and flow is impeded. During normal operation, the disc is held open by compressed-air pistons. When a trip signal is generated, the compressed-air is vented and the valve disc shuts aided by the steam flow. During operation, steam flow assists in closing the valves, and the valves close in a very short time. During cold shutdown, with no motive steam force, the stroke time has always been close to the TS limit of 5.0 seconds. (Note that the times did meet the accident analysis required time for closure). These two valves stroked in slightly greater than 5.0 seconds. The cause analysis concluded that packing adjustments that were made to these valves on-line had more influence on stroke time than expected. The valves were repacked and acceptable stroke time results were obtained. There is no indication that the slow stroke times are related to the August 23, 2011 earthquake.

5. *Describe the scope of the Unit 1 and Unit 2 inservice testing of plant valves and if the valves in the IST program have been or will be tested prior to startup.*

**Dominion Response**

The following provides a summary of the valve testing performed on Unit 1 and Unit 2.

Unit 1 has approximately 110 MOVs in IST Program. The valves have been functionally tested following the August 23, 2011 earthquake except:

- 1-FW-MOV-100D (tested with auxiliary feedwater (AFW) pump testing in Mode 2)
- 1-RH-MOV-1700, 1701, 1720A, 1720B (The valves were opened to place RHR in service and will be stroked closed when RHR is removed from service during unit startup.)

Unit 2 has approximately 110 MOVs in IST Program. The valves have been functionally tested following the August 23, 2011 earthquake except:

- 2-FW-MOV-200D (tested with AFW pump testing in Mode 2)

Unit 1 has approximately 145 AOVs/ SOVs in IST Program. These valves have been functionally tested following the August 23, 2011 earthquake.

Unit 2 has approximately 145 AOVs/ SOVs in IST Program. The valves have been functionally tested following the August 23, 2011 earthquake except:

- 2-MS-PCV-201A/B/C (planned)
- 2-MS-TV-201A/B/C, 213A/B/C (planned)
- 2-MS-TV-209 (planned)
- 2-SS-TV-200A/B, 201A/B, 202A/B, 203A/B, 204A/B, 206A/B, 212A/B (planned)

Relief valves (RVs) are considered robust and review of industry operating experience (OE) does not identify concerns with RVs being damaged by earthquakes. A sampling of IST Program RVs was tested in accordance with the normal Unit 2 refueling outage scope. One bank (five) of Main Steam Safety Valves was functionally tested (representing 33% of Unit 2 population) and one RCS Pressurizer Safety Valve (representing 33% of Unit 2 population) was functionally tested on Unit 2 as part of the refueling outage scope. Each of these valves had successful test results. Twenty-eight (28) RVs were functionally tested (representing greater than 40% of the Unit 2 population) with only one test failure. 2-RH-RV-2721A (1A Residual Heat Removal Pump Suction Header Relief Valve) lifted early at 450 psig outside the acceptable range of 456 – 485 psig. No damage was observed in the valve and valve setting was adjusted to acceptable range satisfactorily. No additional testing of RVs was required by program as other valves in the group were tested satisfactorily. Based on similarities between Unit 1 and 2 equipment, location / orientation in the plant, and support of the valves, Unit 2 results are considered representative of Unit 1 valves. No earthquake damage was identified for IST Program relief valves.

Unit 1 has approximately 180 check valves in the IST Program. Approximately 90 of these valves were tested with satisfactory results after the August 23, 2011 earthquake. No damage has been identified and no test failures have occurred.

Unit 2 has approximately 180 check valves in the IST Program. Approximately 125 of these valves were tested with satisfactory results after the August 23, 2011 earthquake. No damage has been identified and no test failures have occurred.

Unit 1 has approximately 25 manual valves in the IST Program. Each valve has been exercise tested since the August 23, 2011 earthquake except:

- 1-CH-550, charging pump cross-tie valve (typically performed when charging system is removed from service)

- 1-MS-18/57/95, steam supply to turbine for AFW pump, 1-FW-P-2. This test will be performed when unit conditions support (Mode 2) in accordance with TS requirements.

Unit 2 has approximately 20 manual valves in the IST Program. Each valve has been exercise tested since the August 23, 2011 earth quake except:

- 2-MS-18/57/95, steam supply to turbine for AFW pump 2-FW-P-2. This test will be performed when unit conditions support (Mode 2) in accordance with TS requirements.

The Unit 1 and Unit 2 safety related pump and valve inspections and tests have not identified any functional damage attributable to the August 23, 2011 earthquake.

<u>*Steam Generator Inspections*</u>

*The following clarification was requested during a phone call with the NRC on October 18, 2011.*

1. *Provide the final results of Dominion's evaluation of the loose part identified in the Unit 1 Steam Generator.*

**Dominion Response**

Dominion provided updates regarding the loose part identified in the Unit 1 'A' Steam Generator (S/G) in letters dated September 27, 2011 (Serial No. 11-520A) and October 10, 2011 (Serial No. 11-566A).

As part of Dominion's investigation, two potential paths were investigated in an attempt to determine the source of the foreign material: 1) the foreign material originated from the reactor vessel internals, including the fuel assemblies, the Reactor Coolant System (RCS) or a system connected to the RCS (e.g., Safety Injection); or 2) the foreign material originated from a source external to the RCS.

1. <u>From the Reactor Vessel Internals</u> - The components within the Unit 1 reactor vessel and its internals were eliminated as a credible source of the loose parts. The identified loose parts were measured to be approximately 1/8" thick, and had an intentional curvature, suggesting a spring or a clamp around a pipe, conduit, or column. The most similar known component in the reactor internals is a core exit temperature conduit support, but this component is of a different shape, is welded onto the support column and mixing device, and is of a more rugged design than the discovered parts. Westinghouse reactor internals drawings were reviewed and no components of this thickness were identified, which could possibly be used as a shim or as a support to a structural column. Shims described in reactor internals drawings have a thickness of 1/4" or greater, have no curvature, and are specified to precise interference fits. Finally, it is not considered to be reasonable that a component of this curved shape, and low thickness would be used as any sort of spring for large reactor internal components.

   Dominion initially believed, as stated in its letter dated September 27, 2011 (Serial No. 11-520A), that the foreign material had not come from the reactor vessel based on the relatively low radiation levels exhibited by the objects. To confirm this point, an isotopic analysis was performed on the foreign material to determine whether the part had resided in the reactor vessel for any significant period of time. Due to the difficulty of distinguishing between the fixed contamination and the activation exposure rates, the results of this analysis were inconclusive.

   There are two lines which provide a possible flow path, i.e., piping large enough for the foreign material to enter into the 'A' hot leg piping, 1) safety injection line 6"-RC-16-1502-Q1, and 2) reactor coolant loop bypass line 8"-RC-11-2501R-Q1.

The bypass line contains bypass motor operated valve (MOV) 1-RC-MOV-1585, which is installed at an elevation approximately ten (10) feet above the cold leg loop stop valve 1-RC-MOV-1591. The bypass MOV is opened during refueling outages; however, it is improbable that the two pieces of foreign material would follow this torturous path into the hot leg. Furthermore, the 1-RC-MOV-1585 materials list does not contain any parts that match the foreign material in the S/G. Other valves in the RCS and SI systems were also investigated for possible loose parts (e.g., 1-RC-MOV-1590, 1-SI-99, 1-SI-209, 1-SI-240, 1-SI-MOV-1890A, and 1-SI-9). These valves' material lists do not contain any parts that could have generated the S/G 'A' foreign material. In addition, the low head safety injection pump (1-SI-P-1A) was investigated as the possible source of the loose parts. Associated pump drawings were also reviewed. No pump parts were identified that were consistent with the identified foreign material.

It was also considered improbable for the foreign material to have been introduced between the S/G cold leg bowl/nozzle and the reactor inlet nozzle. This is because the foreign material would have had to bypass the Lower Core Plate (i.e., a baffle plate with 2.5" diameter holes), and then penetrate through the fuel assemblies' debris filters. A fuel assembly sits on top of an individual debris filter, and each debris filter is spaced within 40 mils (0.040 inch) of the next filter. Therefore, a 1/8" (0.125 inch) piece of material could not bypass this Foreign Material Exclusion filter screen system. In addition, the pieces were too large to have flowed backwards through the S/G U-tubes (0.875" OD; 0.050" wall thickness) to get into the hot leg bowl.

2. <u>From a Source External to the RCS</u> - Potential sources external to the RCS were also considered. The manipulator crane (1-FH-MH-5) was walked down by the fuel handling crew, and no missing or loose electrical or pipe clamps on the crane were identified. The electrical and pipe clamps on the crane bridge and manipulator mast were visually compared to the loose parts found in the S/G, but none of the equipment used for fuel handling was comparable.

   The Reactor Head O-Ring retainer clips were assessed based on a review of plant Operating Experience; however, the vendor drawing clearly showed that the retainer clips used to hold the reactor O-rings are of a different design than the foreign material found in the S/G.

   The reactor vessel ISI vendor who performed the 2009 10-year reactor vessel ISI inspection was also consulted about the possibility of equipment used during the inspection being the source of the S/G foreign material. When the vendor's robotic system was previously used to perform the 10-year inspection, a locking clamp became disconnected from an Ultrasonic Testing (UT) assembly and resulted in foreign material entering the reactor vessel inlet nozzle. However, the foreign material was successfully recovered by the vendor. The S/G foreign material was compared to the UT parts that had entered the vessel inlet nozzle in 2009, and it is evident that they were not the same type of parts. Neither the physical size nor the material composition matched. The vendor also 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 robot.

Finally, a general walkdown of components near the reactor cavity was performed by station engineering. As previously noted, the foreign material resembles a piping/tubing support; however, no matches could be found. The station planning department also reviewed material stock numbers for stainless steel Uni-strut accessories. No similar material could be identified that would be brought into containment.

3. Time Frame - A time frame of when the material was introduced into the RCS was also investigated. The method used was to trend the alarms from the Vibration and Loose Parts Monitoring System (V&LPMS). This system provides a control room alarm based on exceeding a certain impact energy (Loose Parts Alarm) or a vibration amplitude (Vibration Alarm). Possible causes for the alarm include: excessive loose part noise in any S/G, maintenance in the vicinity of the sensors, large electrical impulse, or equipment vibration due to excessive wear or misalignment. The first possible Loose Parts Alarm for the 'A' S/G was on September 10, 2008. A condition report indicates that a slight pinging was heard on the monitoring panel; however, no indication of a loose part being identified on the loose parts chart recorder is noted. Several condition reports and log entries were made following the Unit 1 2009 spring refueling outage (RFO) in which the loose parts chart recorder indicated one or two small spikes (indicating a small impact). Only one V&LPMS alarm occurred for the Upper Vessel channel, and this coincided with the 'C' S/G alarm on October 20, 2010. The cause for this alarm was determined to be from cold water vibration during the Unit 1 start-up following the fall 2010 RFO. The alarm cleared as RCS temperature increased.

   Because the last 'A' S/G eddy current inspection was performed during the 2007 fall RFO with no foreign material found, and the majority of the loose parts indications (13 plausibles) followed the 2009 spring RFO, there is a high probability that the material was introduced sometime during the 2007 or 2009 RFOs when a large amount of work was performed around the reactor vessel cavity and the S/Gs. The lack of alarms after the 2010 fall RFO could be indicative that the foreign material became lodged in a S/G tube at the tubesheet opening where it was ultimately found.

Conclusion - No definitive source for the 'A' S/G foreign material could be identified. However, 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. The most likely timeframe when such material could have been introduced into the RCS would have been during the 2007 or 2009 RFO. Based on the visual examinations performed during the 'A' S/G tube inspection, the surface of the S/G tube sheet did not show any evidence of impact on the tube sheet clad surface or tube-ends, and no tube wear was observed in the tube (R29 C21) that contained the foreign material. Therefore, there is no evidence that the foreign material caused any damage to the S/G or the RCS in general.

Based on the evaluation discussed above, the introduction of the foreign material into Unit 1 'A' S/G is not believed to be related to the seismic event that occurred on August 23, 2011.

<u>EMCB - Piping</u>

The following clarifications were requested in an E-mail from the NRC on October 24, 2011.

1. *On page 20 of Attachment 1 to letter dated September 27, 2011 (Serial No 11-520A), the licensee provided the results of its inspection of weld SH-37 in Unit 1 safety injection line 10"-SI-238-1502-Q1. The licensee stated that it identified a loose bolt on a spring hanger riser clamp at the weld. The licensee further stated that the condition has been entered into the corrective action system and will be repaired. Discuss whether the repair has been completed. If not, provide a date for the repair.*

**Dominion Response**

The loose spring hanger SH-37 riser bolt was corrected (i.e., retightened) on October 5, 2011 by work order. This work has been completed.

2. *In letter dated October 10, 2011 (Serial No. 11-577), page 9, second paragraph states that "...During a conference call with the NRC on October 7, 2011, Dominion discussed additional justification that it will be providing in support of this conclusion. This information will be provided to the NRC in subsequent correspondence..." Discuss whether the information has been provided. If yes, reference the date and serial number of the letter and specific page. If not, discuss when the information will be provided.*

**Dominion Response**

This information will be provided in Dominion letter (Serial No. 11-577B) that is scheduled to be submitted to the NRC by October 31, 2011. This letter addresses long-term actions, which includes re-evaluation of pipe support structural analyses. (Note: This issue is addressed by NRC Long-Term RAI question EMCB 3 in NRC RAI dated October 13, 2011.

3. *Discuss how the inspections were performed for piping and supports that are located in high elevations or distant away from the operator. For example, discuss the inspection of segment of the containment spray piping system and associated supports that is attached to the ceiling of the primary containment.*

**Dominion Response**

The Quench Spray/Recirculation Spray rings were inspected in both Unit 1 and Unit 2 containments. Station engineers accessed the Polar Crane cat walk (elevation 332') to perform the initial inspections. The initial inspections were documented as identifying no earthquake damage. However, it was noted that visibility was limited due to poor lighting. Subsequently, another team of engineers accessed the platform on the side of the Polar Crane (elevation 344') and re-inspected the areas in both units with the aid of high power flood lights and binoculars. This re-inspection confirmed the results of the initial inspections (i.e., no earthquake damage was identified).

<u>Reactor Vessel Internals</u>

The following clarifications were requested in an E-mail from the NRC on October 24, 2011.

*The September 17, 2011, restart readiness demonstration plan for the North Anna Power Station (NAPS) states that a margin assessment was performed for key reactor vessel internals (RVIs) interface load points in the reactor pressure vessel (RPV) to demonstrate the functionality of the RVIs following the August 23, 2011, seismic event felt at NAPS. Enclosure 3 to the September 17, 2011, submittal states that seismic-only loads were compared with allowable load limits for upset conditions for which no deformation is allowed (i.e., elastic limits). Please address the following items relative to the aforementioned margin assessment:*

*a) The margin only assessment states that only seismic loads were compared against the elastic stress limits. Please confirm that the loads associated with normal operating conditions were also included in the "seismic-only" margin assessment, given that the plant was in a normal operating mode at the time of the August 23, 2011, seismic event. If no other loads were combined with the seismic loads in the margin assessment, please provide justification for the exclusion of other normal operating loads from the loading combination.*

**Dominion Response**

The load combination used in the evaluation discussed in Enclosure 3 of the September 17, 2011 letter (Serial No. 11-520) included normal plus seismic loads. The normal loads accounted for deadweight plus thermal and pressure loads associated with normal operating conditions.

*b) Please confirm that the seismic loads used in the aforementioned margin assessment are those resulting from the NAPS design basis earthquake.*

**Dominion Response**

The seismic loads used in the evaluation discussed in Enclosure 3 of the September 17, 2011 letter (Serial No. 11-520) are those resulting from the North Anna Design Basis Earthquake (DBE), or Operating Basis Earthquake (OBE), whichever produced the maximum calculated load. The OBE loads can be limiting due to the character of the seismic spectra that are defined in the North Anna design basis analyses.

*c) Please provide additional information regarding which RVI interface load points were selected for the margin assessment. Please provide a technical justification which demonstrates that the satisfactory results of the margin assessment for these load* *points envelopes the remainder of the RVIs which were not included in the margin assessment.*

**Dominion Response**

The following interface load points were used in the subject evaluation:

- Vessel – Upper Support Plate, Horizontal
- Vessel – Upper Support Plate, Vertical
- Vessel – Core Support Ledge, Horizontal
- Vessel – Core Support Ledge, Vertical
- Vessel – Core Barrel Nozzle, Radial
- Lower Radial Keys, Tangential
- Lower Radial Keys, Radial
- Lower Radial Keys, Total Sum

The interface load points presented above are taken from the Westinghouse reactor vessel structural analysis design calculation which was performed as part of the transition from Advanced Mark-BW to Westinghouse RFA-2 fuel. The selected load points represent key locations of reactor vessel to internals contact which provide a means to quantify overall loading on the reactor internals structure. Confirming that the DBE interface loads meet limits associated with an OBE no yield condition provides reasonable assurance that individual reactor internals components do not exceed the yield load, with the exception of the lower radial keys, for which results of detailed calculations are discussed in Item e below.

*d) Please provide the results of the aforementioned margin assessment. These results should be in summary form and should demonstrate that adequate margin exists between the stresses developed using the "seismic only" loading combination and the aforementioned elastic stress limits.*

**Dominion Response**

The results of the load margin assessment are provided below in Table 1.

**Table 1: North Anna Units 1 and 2 Reactor Internals Interface Loads[1]**

| Location | Direction | Seismic Loads (includes Deadweight, Thermal, Pressure) | | OBE Load Limits |
|---|---|---|---|---|
| | | OBE (lbf) | DBE (lbf) | Load (lbf) |
| Vessel – Upper Support Plate | Horizontal | 0 | 0 | 162,000 |
| Vessel – Upper Support Plate | Vertical | 544,947 | 529,951 | 1,640,000 |
| Vessel – Core Support Ledge | Horizontal | 0 | 0 | 1,900,000 |
| Vessel – Core Support Ledge | Vertical | 1,013,347 | 977,613 | 2,250,000 |
| Vessel – Core Barrel Nozzle | Radial | 1,294 | 15,510 | 225,000 |
| Lower Radial Keys | Tangential | 48,176 | 96,671 | 100,000 |
| Lower Radial Keys | Radial | 0 | 0 | 0 |
| Lower Radial Keys | Total Sum | 48,176 | 96,671 | 100,000 |

[1] Zero loads signify that the gaps at those locations between components are not fully closed, so there are no impact loads.

e) *Please provide justification which demonstrates that the use of the seismic loads in the current (existing) analyses of record provides reasonable assurance that adequate margin exists between the elastic stress limits and the loads which were induced in the RVIs during the August 23, 2011, seismic event felt at NAPS.*

**Dominion Response**

The results summarized in Table 1 indicate that the selected interface loads calculated for either the OBE or DBE have a considerable amount of margin compared to the qualified load limits associated with the OBE, with the exception of the lower radial keys. The qualified OBE load limit corresponds to no yield in the components. The calculated loads listed for the vessel upper support plate and core support ledge may be doubled and still not exceed the OBE load limits. For the radial keys, a supplemental stress analysis has been performed using calculated loads from a reactor vessel seismic analysis of the August 23, 2011 event. Table 2 presents the maximum primary stresses in the lower radial key from this supplemental analysis for the analyzed load associated with the August 23, 2011 event.

**Table 2: Lower Radial Key Primary Stresses**

| Primary Membrane Stress, $P_m$ (psi) | Primary Bending Stress, $P_b$ (psi) | $P_m + P_b$ (psi) |
|---|---|---|
| 12,320 | 14,000 | 21,320 |

At 600°F, the key material's allowable membrane stress ($S_m$) is 16,600 psi. For Level A and B conditions (no yield), the margin for primary membrane stress is:

$$MS_{mem} = \frac{S_m}{P_m} = \frac{16{,}600 \text{ psi}}{12{,}320 \text{ psi}} = 1.347$$

The margin for primary membrane-plus-bending stress is:

$$MS_{mem+bend} = \frac{1.5*S_m}{P_m + P_b} = \frac{24{,}900 \text{ psi}}{21{,}320 \text{ psi}} = 1.168$$

These results demonstrate that 16% margin exists to the no yield stress limit for the lower radial key with the loading resulting from the August 23, 2011 earthquake.