Exhibit DVP-003

March 2, 2017

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Commission

In the Matter of	)	
	)	
Dominion Virginia Power	)	Docket No. 52-017-COL
	)	
North Anna Power Station, Unit 3	)	

DOMINION VIRGINIA POWER'S
RESPONSES TO PRE-HEARING QUESTIONS

In accordance with the Notice of Hearing[1] and the Nuclear Regulatory Commission's (Commission) Order (Transmitting Pre-Hearing Questions) (Feb. 17, 2017), Virginia Electric and Power Company, dba Dominion Virginia Power (Dominion), submits the following responses to each of the questions posed to it by the Commission.

Question 1: In Request for Additional Information 5693, 2.5.2-3a, dated May 5, 2011 (ML11125A124), the Staff asked the Applicant to justify the one-dimensional (1D) site response analysis using only vertically propagating shear waves, given the complex topography of the subsurface layers. On August 25, 2011 (ML11241A058), the Applicant responded that the soil and rocks at the site are all derived from the same parent rock. The Applicant attributed the subsurface variability to the localized effects of weathering on minerals comprising the parent rock rather than to deposition of soil as distinct layers. For lateral variability, the Applicant states that the boundaries between rock types are gradational and so do not represent lateral impedance boundaries that may result in refraction, reflection, or trapping of the shear waves traveling in horizontal directions. Therefore, the site can be characterized as undulating, but not *dipping*, thus justifying the 1D analysis. The Applicant uses the same weathering process to explain the existence of vertical variation, but with distinct boundary impedances at different depths as shown in Final Safety Evaluation Report (FSER) Figure 2.5.2-5. Please discuss why the same weathering mechanism generates sharp boundaries vertically, but not laterally.

Response: The North Anna site is located within the Piedmont Upland Section of the Piedmont Physiographic Province – the topography in the site region is described as gently undulating, with slopes typically ranging from 2 to 5 percent. The bedrock formation immediately below the

[1] Dominion Virginia Power, North Anna Unit 3, Combined license application; hearing, 82 Fed. Reg. 8,864 (Jan. 31, 2017).

North Anna site, termed the Ta River Metamorphic Suite, is estimated to be several hundred million years old (Cambrian and/or Ordovician) and about 10,000 feet thick. The Ta River Metamorphic Suite consists of a sequence of amphibolites and amphibole-bearing gneisses with subordinate quartzites and biotite gneiss. These rocks are interpreted as a metamorphosed oceanward side of an Ordovician-age volcanic island arc.

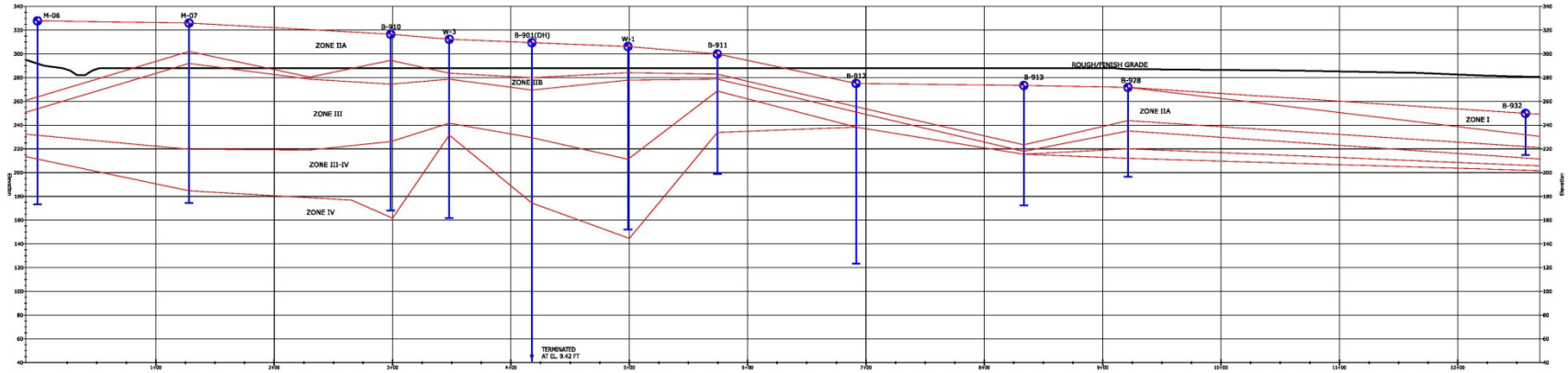
Weathering, the process of breaking rock down to soil, has probably been active during the past tens of millions of years, since regional uplift of the Piedmont Province. The weathering process starts from the surface and progresses vertically downwards – it can be physical, chemical or biological. Physical weathering is caused by processes such as freezing and thawing, wetting and drying, and shrinking and swelling. In chemical weathering, the rock decomposes through a series of chemical processes such as dissolution, oxidation and acidification. Biological weathering is most commonly characterized by the effects of tree and plant roots.

The end product of rock weathering depends on the composition of the rock and the weathering processes. The various stages of the weathering in place of the North Anna bedrock can be seen in Figure Q1-1 (FSER Figure 2.5.4-1 modified to remove the vertical scale exaggeration). The sound bedrock (Zone IV) degrades to slightly-to-moderately weathered rock (Zone III-IV), then weathered rock (Zone III), then saprolite (Zones IIA and IIB) which is mainly granular soil that still exhibits the structure of the bedrock, and finally clay soil (Zone I) which contains no relict bedrock structure and is now mostly absent from the site. Because of the vertical progression of the weathering process, these zones are nominally horizontal. Some random lateral variation (as seen in Figure Q1-1) occurs because the weathering processes are not always uniform, and the rock is not entirely homogeneous. It should be noted that the zone separations depicted on the figure are made by joining the zone boundaries in the borings by straight lines for simplification

– in reality these changes will be a gradual transition (similar to the ground surface) and thus the description of "undulating."

The question references FSER Figure 2.5.2-5 (shear wave velocity (Vs) profiles for the Reactor Building/Fuel Building (RB/FB) and Control Building (CB) used in site response analysis) as depicting the distinct boundary impedances at different depths. As described above, these are boundaries of variation of impedance in the vertical direction (termed "vertical impedance boundaries" here) defined by the approximately horizontal zone boundaries caused by weathering. Because the weathering impact on the rock is severe, the vertical impedance boundaries are significant, as illustrated in FSER Figure 2.5.2-5. The random and relatively small lateral variations as shown on the figure do not produce equivalent lateral impedance boundaries. The vertical impedance boundaries of the Vs profiles in FSER Figure 2.5.2-5 are somewhat simplified for use as input to the site response analysis. The Vs values are averaged over 10 ft intervals, and thus the sharp impedance boundaries in FSER Figure 2.5.2-5 do not reflect the transitions between zones that inevitably occur in a weathering profile. These slight approximations are accounted for in the randomization of the Vs profile as part of the response analysis. Similarly, local variations in the Vs profile due to variations in the weathering patterns are taken into account in the randomization process.

The question notes the reference to the site being characterized as undulating rather than dipping to justify the 1D analysis. In a dipping rock site, layers that are present on one end of the site may be absent on the other end, and vice versa. If these layers have distinctly different dynamic properties (Vs, damping, etc.), then the site response can be quite different at either end of the site – and additional analytical efforts would be needed to reconcile this situation. As described above, this is not the case with the undulations at the North Anna site.



NOTE:
THE CONVERSION FROM NAVD88 DATUM ELEVATIONS TO NGVD29 DATUM ELEVATIONS IS +0.86 FT

SUBSURFACE PROFILE A-A

0 25 50 100 150 200FT

VERTICAL EXAGGERATION = 1:1

Figure Q1-1 – Typical Subsurface Profile across Unit 3 Power Block Area
(FSER Figure 2.5.4-1 Modified to Remove Vertical Exaggeration)

Question 2: The FSER states that the Applicant concluded that the three-component strong ground motion accelerograms of the M5.8 Mineral earthquake recorded at the North Anna Unit 1 structure (the closest available strong motion recordings of the Mineral earthquake) "correlated well with ground motion prediction equations [(GMPEs)] for the [central and eastern United States] at high frequencies (peak ground acceleration (PGA), 5 Hz[)] but [that they] were lower than predicted at low frequency (1 Hz)."

Since the GMPEs describe the *free-field* ground motion at a given location, how is the correlation with the recorded motion on the containment mat foundation (not a free-field location) justified?

Response: The observation made regarding the 2011 Mineral, Virginia earthquake in comparison with eastern ground motion prediction equations is based on strong motion recordings consistent with the Center for Engineering Strong-Motion Data (CESMD) data, which do not include the ground motions recorded at the North Anna Unit 1 structure.

Section 2.5.2.1.3 of the North Anna Unit 3 Final Safety Analysis Report (FSAR), Significant Site Earthquakes, discusses in detail the various observations and characteristics of the 2011 Mineral, Virginia earthquake, and includes a subsection entitled "Strong-Motion Records." The initial portion of this subsection describes the observations of recorded motions on the containment mat foundation and containment operating deck locations at North Anna Unit 1. At the end of this discussion, the FSAR states:

> Reference 2.5-386 [Graizer et al., 2013] concludes that when comparisons are made between the time histories of the containment mat foundation and containment operating deck records, it is apparent that both sets of recordings are affected by the structure and should not be considered equivalent to free-field recordings.

A subsequent paragraph proceeds to discuss other observed ground motions from the 2011 Mineral, Virginia earthquake, as compiled by the CESMD. FSAR Table 2.5.2-205 lists these CESMD data, and does not include the North Anna Unit 1 data. The FSAR then observes:

> At short periods (PGA, 0.2s), ground motions agreed well with eastern ground-motion prediction equations, but were less than expected at longer periods (1.0s) (Cramer et al., 2012) (Reference 2.5-234).

Therefore, FSAR Section 2.5.2 does not suggest that the North Anna Unit 1 containment mat foundation recordings of the 2011 Mineral, Virginia earthquake represent free-field measurements or were compared with the GMPEs.

Question 3: The Applicant requested a variance from ESP, Appendix A, Figure 1, Note 2, which states, "Abandoned Unit 3 and 4 Reactor Building Mat Foundations are to be removed." The requested variance, however, also indicates that the Applicant would "not remove the abandoned mat foundations … unless a Unit 3 Seismic Category I or II structure would be located above an abandoned foundation."

For the Staff: The Staff states that the site layout in Final Safety Analysis Report (FSAR) Figure 2.4-201 is subject to control under the provisions of 10 C.F.R. § 50.59, and this control is sufficient to ensure that Dominion will account for any effect the abandoned mat foundations might have. Please explain in more detail why the provisions of 10 C.F.R. § 50.59 are sufficient in this context.

For the Applicant: Please explain why the variance indicated the abandoned mat foundations would not be removed unless a Unit 3 Seismic Category I or II structure would be located above an abandoned foundation. Does the Applicant anticipate the need to relocate the Unit 3 Seismic Category I or II structures from the coordinates in the FSAR?

Response (pertaining to Applicant): Figure 1 of Appendix A to the Early Site Permit (ESP) documents the boundaries within which new reactor facilities may be located, including any Seismic Category I or II structures. The abandoned Units 3 and 4 reactor building mat foundations are located within the ESP-established boundary. At the time that the ESP application (ESPA) was developed, Dominion had not chosen a specific reactor technology; therefore, the specific location of Seismic Category I or II structures within the boundary was unknown.

Note 2 states: "Abandoned Unit 3 and 4 Reactor Building Mat Foundations are to be removed." Dominion included Note 2 on Figure 1.0-1 of the ESPA Site Safety Analysis Report (SSAR), conservatively assuming that a Seismic Category I or II structure might be placed in the location currently occupied by the abandoned mat foundations, thus first necessitating removal of the foundations.

For the North Anna Unit 3 combined license application (COLA), Dominion selected the ESBWR reactor technology. Once the ESBWR reactor was selected, the specific arrangement of ESBWR facilities (including Seismic Category I and II structures) became known. As shown in FSAR Figure 2.0-205 and FSER referenced FSAR Figure 2.4-201, Dominion was able to site the ESBWR facilities within the ESP-established boundary such that no Seismic Category I and II structure would be located in the location currently occupied by the abandoned Units 3 and 4 reactor building mat foundations. Therefore, there is no need to remove the abandoned mat foundations as specified by Note 2 and a variance from the requirement to do so was needed.

The discussion included in variance NAPS ESP VAR 2.0-7 that Dominion would "not remove the abandoned mat foundations for the originally planned North Anna Units 3 and 4 unless a Unit 3 Seismic Category I or II structure would be located above an abandoned foundation" was intended to serve as the generally applicable criterion for determining the need for removal. By locating the ESBWR facilities such that no Seismic Category I or II structure is located at the location of the abandoned foundations, the condition set forth by the variance is met. Therefore, as stated in variance NAPS ESP VAR 2.0-7, "it is no longer necessary to remove the abandoned foundations."

Question 5: Instead of providing the information to meet the requirements of 10 C.F.R. §§ 50.54(w), 140.11(a)(4), and 140.21 at the time of COL issuance, the Applicant proposed two license conditions to meet these requirements. The Staff accepted the conditions with minor variations and found that with the conditions the Applicant met all applicable requirements. Why is it acceptable to meet these requirements with a license condition without taking an exemption from the regulation?

Both license conditions require action "before the scheduled date for initial fuel load." Therefore, why are these requirements included as license conditions and not as Inspections, Tests, and/or Analyses and Acceptance Criteria?

Response: License Conditions 2.E.(1) and (2) in the draft combined license (COL) relate to provisions of NRC regulations that are not required to be implemented at the time of COL

issuance. As explained in more detail below, no exemptions are necessary, and including these requirements as part of Inspections, Tests, Analyses and Acceptance Criteria (ITAAC) is not consistent with the purpose of ITAAC.

The second sentence in 10 C.F.R. § 50.54 states, "The following paragraphs with the exception of paragraph (r), (s), and (u) of this section are conditions in every combined license issued under part 52 of this chapter, provided, however, that paragraphs (i) introductory text, (i)(1), (j), (k), (l), (m), (n), (w), (x), (y), (z), and (hh) of this section are only applicable after the Commission makes the finding under § 52.103(g) of this chapter." Therefore, the provisions of 10 C.F.R. § 50.54(w) are not required to be met until after the § 52.103(g) finding, and no exemption is necessary.

The general language in 10 C.F.R. § 140.11(a)(4) is superseded by the more specific provisions in 10 C.F.R. § 140.13 governing the financial protection required to be provided by a COL holder prior to the § 52.103(g) finding. 10 C.F.R. § 140.13, "Amount of financial protection required of certain holders of construction permits and combined licenses under 10 CFR part 52," provides that:

> Each holder of a part 50 construction permit, or a holder of a combined license under part 52 of this chapter before the date that the Commission had made the finding under 10 CFR 52.103(g), who also holds a license under part 70 of this chapter authorizing ownership, possession and storage only of special nuclear material at the site of the nuclear reactor for use as fuel in operation of the nuclear reactor after issuance of either an operating license under 10 CFR part 50 or combined license under 10 CFR part 52, shall, during the period before issuance of a license authorizing operation under 10 CFR part 50, or the period before the Commission makes the finding under § 52.103(g) of this chapter, as applicable, have and maintain financial protection in the amount of $1,000,000. Proof of financial protection shall be filed with the Commission in the manner specified in § 140.15 of this chapter before issuance of the license under part 70 of this chapter.

This provision in 10 C.F.R. § 140.13 is more specific than the general language in 10 C.F.R. § 140.11(a)(4), and specifically controls the amount and timing of the financial protection that must be provided by a COL holder prior to the § 52.103(g) finding. As the Commission has held, "It is well-established that specific regulations . . . control over general regulations. . ." *DTE Electric Co.* (Fermi Nuclear Power Plant, Unit 3) et al., CLI-15-10, 81 N.R.C. 535, 540 (2015) (citations omitted). Therefore, under the NRC rules, a COL holder is not required to meet the provisions in 10 C.F.R. § 140.11(a)(4) prior to the § 52.103(g) finding, and no exemption is necessary.

10 C.F.R. § 140.21 requires that each licensee required to maintain financial protection under 10 C.F.R. § 140.11(a)(4) shall provide evidence that it maintains a guarantee of payment of deferred premiums in the amount specified in § 140.11(a)(4). Because a COL holder is not required to meet the financial protection amounts in § 140.11(a)(4) prior to the § 52.103(g) finding, for the reasons discussed above, the requirement in 10 C.F.R. § 140.21 does not become applicable until the § 52.103(g) finding. Therefore, no exemption is necessary.

10 C.F.R. § 52.97(b) provides that:

> The Commission shall identify within the combined license the inspections, tests, and analyses, including those applicable to emergency planning, that the licensee shall perform, and the acceptance criteria that, if met, are necessary and sufficient to provide reasonable assurance that the facility has been constructed and will be operated in conformity with the license, the provisions of the Act, and the Commission's rules and regulations.

The insurance and financial protection requirements addressed in License Conditions 2.E.(1) and (2) in the draft COL do not relate to tests, inspections or analyses that are specified to ensure a plant has been constructed and will be operated in conformity with the license, the Atomic Energy Act, and NRC rules; and they are also unrelated to acceptance criteria verifying that plant systems, structures and components (SSCs) have been constructed as designed, or that

operational programs have been developed. Further, Section 170(a) of the Atomic Energy Act provides that the financial protection required by the Commission shall be a condition of each license. Similarly, 10 C.F.R. § 50.54 specifies that the provisions in this rule, including the property insurance requirements, are a condition of each license. Thus, use of license conditions for these financial and insurance requirements is appropriate.

Question 6: The Staff's Statement in Support of the Uncontested Hearing for Issuance of a Combined Licensed for North Anna Power Station Unit 3 notes that, because the site-specific seismic conditions for North Anna Unit 3 are not bounded by the ESBWR Design Control Document seismic design parameters, the Applicant defines the SSE to include the Certified Seismic Design Response Spectra (CSDRS) and the site-specific foundation input response spectra (FIRS) for each seismically qualified structure. What are the practical implications for the SSE being defined in this manner as far as assessing future modifications to the plant with respect to seismic safety?

Response: The practical implication of the Safe Shutdown Earthquake (SSE) definition is that any future modification to an SSC required to withstand SSE loads must be designed, analyzed, and qualified for SSE demands defined by both the CSDRS and the site-specific FIRS. This assessment is well within normal engineering capabilities.

Part 10 of the COLA, "Tier 1/ITAAC/Proposed License Conditions," and FSAR Section 3.7.1, define the Unit 3 seismic design motion, as follows:

> SSE design ground motion for purposes of seismic design, analysis, and qualification of Unit 3 plant SSCs, is defined by two sets of ground motion acceleration response spectra:
>
> - the single envelope design ground motion response spectra or CSDRS described in FSAR Section 3.7.1.1.3 that defines the SSE design motion for seismic design of ESBWR Standard Plant, and
> - the site-specific FIRS described in FSAR Section 3.7.1.1.4.2, representative of the Unit 3 site specific seismological and geological conditions.

The above definition is applicable to SSCs that are required to withstand SSE loads, through the entire life of the plant. Therefore, each SSC required to withstand SSE loads that is affected by a

future modification must be designed, analyzed, and qualified using the methodology specified in FSAR Sections 3.7 and 3.8 for SSE demands defined by the CSDRS and the site-specific FIRS.

The NRC acknowledges the applicability of the definition of the Unit 3 SSE in the FSER. As noted in FSER Section 3.7.1.4, the SSE as defined in FSAR 3.7.1 will be applied for any future potential plant modifications. Specifically, Section 3.7.1.4 states:

> The site-specific definition of SSE will be applied in the ITAAC for ensuring seismic capability of the plant as designed, as constructed, and for any future potential plant modifications.

Question 7: Please provide the regulatory basis for the requirement that the schedule for implementation of the operational programs listed in FSAR Table 13.4-201, "Operational Programs Required by NRC Regulations," includes site-specific Severe Accident Management Guidelines.

Response: Table 13.4-201 of the FSAR does not identify site-specific Severe Accident Management Guidelines (SAMG) as an operational program by NRC regulations. In a Staff Requirements Memorandum pertaining to SECY-15-0065 – Proposed Rulemaking: Mitigation of Beyond-Design Basis Events (August 27, 2015), the Commission disapproved proposed requirements for SAMG, maintaining them as voluntary. However, the development of an accident management program and severe accident guidelines is part of the procedure development under Section 18.9 and Reference 18.9-1 of the ESBWR Design Control Document (DCD) (relating to human factors engineering), which the FSAR incorporates. In addition, Chapter 19 of the DCD identifies a severe accident management program as an example of COL holder programs that would be supported by the probabilistic risk assessment. *See* ESBWR DCD, §§ 19.2.2.2.1, 19.2.2.3.1, 19.2.2.4.1. Thus, Condition 2.D.(11) in the draft COL, which Dominion proposed in Part 10 of the COLA to require the schedule for implementation of the

operational programs in FSAR Table 13.4-201 to "also address" site-specific SAMG, is consistent with the programs contemplated by the DCD.

Question 8: Please explain the relationship between conditions 2.B.(1)(a) and (b) in the draft COL. Condition (a) appears to grant Dominion authority to operate the facility, while condition (b) appears to remove that same authority. When the owner and operator of the facility are the same company—as is the case here—is it necessary to include condition (b) in the COL?

If the Staff intends to retain the condition, please discuss the reason for the difference between the North Anna and Fermi licenses.

Response: Condition 2.B.(1)(b) was erroneously included in the draft COL. Condition 2.B.(1)(b) is a provision that would be included in a license to authorize a non-operating co-owner. As North Anna Unit 3 is wholly owned by Dominion, the COL should not include this provision.

Question 9: License Condition 2.D.(2), "Startup Administration Manual, Preoperational and Startup Test Procedures," was not included in the Fermi COL. Please discuss why it was added for this subsequent COL.

Response: Dominion included proposed license conditions for the "Startup Administration Manual, Preoperational and Startup Test Procedures" in the COLA to be consistent with the Reference combined license application (R-COLA) for the ESBWR design-center, Fermi 3. The Fermi 3 applicant, DTE Energy, had included the same proposed license conditions, with only minor differences, in the R-COLA in response to NRC Request for Additional Information (RAI) 14.02-4 (ML101960646; ML12170A664).

The NRC Staff included the proposed license conditions in paragraph 2.D.(2) of the draft COL for North Anna Unit 3.

Question 11: 10 C.F.R. § 52.79(b)(3) states that any terms and conditions of the early site permit (ESP) that could not be met by the time of COL issuance "must be set forth as terms or conditions of the combined license." Section 3.E of the North Anna ESP includes six site-specific conditions. Please describe where these conditions were met in the FSAR and evaluated in the FSER or where they appear in the draft COL.

Response: FSAR Table 1.10-202, Summary of FSAR Sections Where ESP COL Action Items and Permit Conditions Are Addressed, provides the FSAR section(s) where each North Anna ESP Section 3.E permit condition is addressed. A more detailed description of where in the FSAR each applicable ESP condition is met or where the condition appears in the draft COL is provided below.

<u>Permit Condition 3.E.(1)</u>

This permit condition (PC) was deleted by an amendment to the ESP issued on October 30, 2008 (ML082820068). This deleted condition, which had previously required an applicant referencing the ESP to execute an agreement providing for the applicant's control of the North Anna ESP site exclusion area and obtain all approvals required by State law in connection with that agreement before the commencement of construction, was directed to the original ESP holder, Dominion Nuclear North Anna. LLC (DNNA), and became unnecessary when the ESP was transferred to Dominion and Old Dominion Electric Cooperative (ODEC). (By Order dated January 30, 2013 (ML12297A196), the NRC later approved the transfer of ODEC's interest in the ESP to Dominion.) As discussed in FSAR Section 2.1.2.1 and FSER Section 2.1.4, Dominion currently controls the NAPS site and exclusion area under its existing agreement with ODEC, and no approvals are required by state law for shared control of the exclusion area.

Permit Condition 3.E.(2) – *An applicant for a CP or COL referencing this ESP for a second new unit shall use a dry cooling tower system to remove waste heat from the working fluid passed through the turbine/generator set during normal operation.*

This permit condition is not applicable to North Anna Unit 3 because it is not a second unit referencing the ESP.

Permit Condition 3.E.(3) - *An applicant for a CP or COL referencing this ESP shall ensure that any new unit's radioactive waste management systems, structures, and components, as defined in Regulatory Guide 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants," for a future reactor include features to preclude accidental releases of radionuclides into potential liquid pathways.*

FSAR Section 2.4.13.1 describes the mitigating design features which demonstrate that the radioactive waste management systems, structures, and components for Unit 3, as defined in Regulatory Guide 1.143, include features to preclude accidental releases of radionuclides into potential liquid pathways; therefore PC 3.E.(3) is met.

An evaluation of PC 3.E.(3) is provided in FSER Section 2.4.13.4.

Permit Condition 3.E.(4) - *An applicant for a CP or COL referencing this ESP shall excavate weathered or fractured rock at the foundation level and replace it with lean concrete before the commencement of foundation construction for safety-related structures.*

FSAR Section 2.5.1.2.6 describes that weathered or fractured rock at the foundation level for safety-related structures will be excavated and replaced with lean concrete before initiation of foundation construction; therefore PC 3.E.(4) is met.

An evaluation of PC 3.E.(4) is provided in FSER Sections 2.5.1.4, 2.5.1.6, 2.5.4.4, and 2.5.4.4.5.

Permit Condition 3.E.(5) - *The permit holder and an applicant for a CP or COL referencing this ESP shall not use an engineered fill with high compressibility and low maximum density, such as saprolite.*

FSAR Sections 2.5.1.2.3 and 2.5.4.5.3 describe that Zone IIA soil will not be used as structural fill to support Seismic Category I or II structures; therefore PC 3.E.(5) is met.

An evaluation of PC 3.E.(5) is provided in FSER Sections 2.5.1.4, 2.5.1.6, 2.5.4.4, and 2.5.4.4.5.

Permit Condition 3.E.(6) - *If the ESP holder performs an excavation for a safety-related structure, the ESP holder shall perform geologic mapping of such excavation, evaluate any unforeseen geologic features that are encountered, and notify the NRC no later than 30 days before any such excavation is open for NRC examination and evaluation. An applicant for a CP or COL referencing this ESP shall perform geologic mapping of any excavation for a safety-related structure, evaluate any unforeseen geologic features that are encountered, and notify the NRC no later than 30 days before any such excavation is open for NRC examination and evaluation.*

FSAR Sections 2.5.1.2.6 and 2.5.4.5.2 describe that the excavation for safety-related structures will be geologically mapped and photographed by experienced geologists, unforeseen geologic features that are encountered will be evaluated and that the NRC will be notified no later than 30 days before any excavations for safety-related structures are open to allow for NRC Staff examination and evaluation; therefore PC 3.E.(6) is met.

An evaluation of PC 3.E.(6) is provided in FSER Sections 2.5.1.4, 2.5.1.5 (COL License Condition), 2.5.1.6, 2.5.4.4, and 2.5.4.4.5.

The draft COL includes site-specific condition 2.D.(12)(e) that Dominion shall perform detailed geologic mapping of excavations for safety-related structures; examine and evaluate geologic features discovered in these excavations; and shall notify the Director of the Office of New Reactors (NRO), or the Director's designee, in writing, no later than 30 days before any such excavations are open for NRC examination and evaluation. The requirements of 10 C.F.R. § 52.79(b)(3) are met by inclusion of this requirement as a condition of the COL.

Permit Condition 3.E.(7) - *An applicant for a CP or COL referencing this ESP shall improve Zone II saprolitic soils to reduce any liquefaction potential if safety-related structures are to be founded on them.*

FSAR Section 2.5.4.8 states that all of the Seismic Category I structures are founded on rock or on concrete fill on rock at the Unit 3 site; therefore PC 3.E.(7) is met.

An evaluation of PC 3.E.(7) is provided in FSER Sections 2.5.4.4 and 2.5.4.4.8.

Question 12: What is the status of pending environmental permits, certifications, and authorizations?

Response: A list and description of Federal, State and Local authorizations that will be required in order to construct and operate North Anna Unit 3 is included in Table 1.2-1 of Dominion's Environmental Report (ER), Revision 8, which was submitted to the NRC in June 2016.

Except as noted below, the information in Table 1.2-1 of Revision 8 of Dominion's ER remains accurate:

- Table 1.2-1 identifies the certificate of public convenience and necessity (CPCN) as necessary for construction, but does not further describe the status of this certificate. As Dominion has not yet made a decision to build, there is currently no schedule for submittal of the CPCN application.
- Virginia Marine Resources Commission (VMRC) permit #10-1256, which is required by the Rivers and Harbors Act, and Title 28.2 of the Code of Virginia – Fisheries and Habitat of The Tidal Waters – that addresses impacts to navigable waters, was received but never became effective pending payment of royalties and formal execution of the documents. This permit will be obtained prior to commencement of any covered activities.
- Because of concerns raised by individuals about potential impacts to populations of the Sensitive Joint-Vetch (*Aeschynomene virginica)* along the Mattaponi River resulting from barges transporting large components to the roll-off facility near Walkerton, Virginia in November 2016, the U.S. Army Corps of Engineers suspended the Clean Water Act (CWA) Section 404 permit that authorized impacts related to the Mattaponi

River roll-off facility pending the resolution of additional consultations between NRC and the U.S. Fish and Wildlife Service (USFWS) under Section 7 of the Endangered Species Act. As part of the Section 7 consultation, NRC submitted to USFWS on December 9, 2016, a Supplemental Biological Assessment (BA) (ML16312A319, ML16312A320) updating the assessment that was performed for the ESP and evaluating the impact of construction and operation of the new nuclear unit on federally protected species within the jurisdiction of the USFWS. This Supplemental BA included an evaluation of potential impacts to Sensitive Joint-Vetch populations along the barge transport route and concluded that the project is not likely to adversely affect the Sensitive Joint-Vetch. In addition, in a letter dated February 20, 2017 (ML17053B270), Dominion committed to additional measures for avoiding impacts to Sensitive Joint-Vetch populations. By letter dated February 22, 2017 (ML17058B064), the USFWS concurred with the Supplemental BA and Dominion's proposed actions, completing the Section 7 consultation.

- In April 2016, as part of its consultations with U.S. National Marine Fisheries Service (NMFS), the NRC prepared a BA determining that the proposed action is not likely to adversely affect the Atlantic Sturgeon or other species subject to the jurisdiction of NMFS. The NMFS concurred with this assessment on November 3, 2016.

Question 15: Please describe the Staff's National Historic Preservation Act (NHPA) Section 106 consultation efforts since publication of the Final SEIS.

Response: The North Anna Unit 3 Supplemental Environmental Impact Statement (SEIS) was published as NUREG-1917 in February 2010, and included a February 3, 2009 letter from the Virginia Department of Historic Resources (VDHR) finding that, with the commitments reflected in the SEIS, a determination of no adverse effect to historic properties is appropriate.

In February 2011, after Dominion revised its application to reference the US-APWR technology, the NRC published a notice in the Federal Register notifying the public of its intent to prepare a supplement to the SEIS, and reinitiated consultation with the VDHR. Subsequently, in a letter dated September 1, 2011 (ML14175A297), Dominion summarized the consultations that had continued with the VDHR. By letter dated October 5, 2011 (ML11298A131), the VDHR confirmed that Dominion's September 1, 2011 letter accurately summarized the consultations and commitments that had occurred to date. After Dominion reverted to the ESBWR technology, the NRC Staff notified the VDHR that it would no longer be preparing a supplement to the SEIS and sought confirmation that consultation under Section 106 of the National Historic Preservation Act was complete. By letter dated October 3, 2014 (ML16172A193), the VDHR responded confirming that, subject to the commitments summarized in Dominion's October 5, 2011 letter, the February 3, 2009 finding of no adverse effect remains valid and the Section 106 consultation is considered complete.

As reflected above, Dominion has maintained close coordination with VDHR since the preparation of the COLA ER and subsequent publication of the SEIS. The Environmental Protection Plan included as Appendix B to the draft COL requires Dominion to implement the commitments that Dominion has made to the VDHR to protect historic and cultural resources. The NRC has continued to monitor for project changes or environmental factors that could be considered new and significant. These monitoring activities include audits, the most recent of which was documented in a letter to Dominion dated December 22, 2016 (ML16288A846). Based on the audit and follow up discussions, the NRC Staff determined all historic and cultural documentation was complete.

Question 20: Did the Applicant propose any novel environmental approaches in the environmental portion of its application? How did the Staff address these approaches?

Response: Dominion does not view its approach in the environmental portion of the COLA as "novel." Dominion did, however, use a previously untested element of the Part 52 process during the environmental portion of the licensing action. This element was to reference an ESP that is based on a plant parameter envelope (PPE) and demonstrate that the reactor technology selected for the COLA fell within the PPE established by the ESP. The NRC Staff described its approach for conducting a PPE-based review in the Final SEIS:

> During the NAPS ESP review, the staff evaluated a set of values of plant design parameters for the reactors and associated facilities. This set of values, or plant parameter envelope (PPE), serves as a surrogate for actual reactor design information. The approval of the ESP bound these values and assumptions for the COL review. In the COL application, Dominion provided the actual values for most parameters when it chose a reactor design. The staff's analysis of the environmental impacts associated with the COL will confirm the reactor design values provided in the COL application and necessary PPE values are bounded by the ESP and other required NRC regulations.

NUREG-1917 at 1-3.

Question 21: Please highlight major themes from the comments on the Draft SEIS, and generally describe the Staff's responses to those comments.

Response: The NRC Staff issued the North Anna Unit 3 Draft SEIS for public comment in December 2008. The comment period closed on March 20, 2009. The comments that were received and the NRC Staff's responses are documented in Appendix E to the Final SEIS. The NRC Staff received comments on topics that were within the scope of the environmental review, along with some comments on topics that were outside the scope of the environmental review.

With respect to the comments on topics within the scope of the NRC Staff's environmental review, the themes identified related primarily to the areas of hydrology-surface water, ecology (terrestrial and aquatic), energy alternatives, and need for power. Some comments related to

topics that were resolved at the ESP stage. For each of these comments, the NRC Staff noted that the comment was resolved in the ESP Final Environmental Impact Statement (FEIS) and identified the appropriate section where the topic was discussed. For comments which addressed issues discussed in the Draft SEIS, the NRC Staff typically made a conclusion as to whether the comment provided new and significant information and stated whether or not changes were made to the Draft SEIS.

Some comments addressed topics and issues that are outside the scope of the environmental review. These comments included questions about the NRC's safety review, general statements of support or opposition to nuclear power, observations regarding national nuclear waste management policies, comments on the NRC regulatory process in general, and comments on NRC regulations. With respect to these comments, the NRC Staff generally either acknowledged the commenter's position or explained why the matter raised was not within the scope of the NRC's environmental review.

Question 23: On February 4, 2017, a member of the public filed a comment on the public docket that raised concerns with whether the need for power analysis in Chapter 8 of the Final SEIS met the guidance of NUREG-1555 (available at ML17037D071). Because the Applicant did not address its need for power in the ESP proceeding, it is within the scope of the COL review. Please respond to the arguments made in the public comment.

Response: Ms. Noakes raises a concern whether the need for power analysis meets the guidance in the Environmental Standard Review Plan (NUREG-1555). She also raises concerns with two areas of the discussion of alternatives. These concerns are addressed below.

Ms. Noakes challenges the demand growth assumption that was included in the need for power analysis in the original ER, submitted in 2007. Dominion updated the need for power analysis in Revision 6 of the ER in 2013. The revised analysis showed a continued need for power, despite the slower demand growth rate of approximately 1.8% projected for the period of 2013 to 2028.

The NRC Staff subsequently determined that there was no need to supplement the Final SEIS. Dominion and the NRC Staff have continued to assess whether there has been new and significant information affecting the conclusions of the environmental review. This assessment has included examination of the demand projections and estimated capacity requirements in Dominion's Integrated Resource Plans (IRP) since Dominion's update of its need for power analysis. The IRPs continue to reflect a substantial need for new capacity.

The 2006 peak demand and energy forecast included in the need for power analysis of the original ER included a 2.4% growth rate for the next ten years (2006 – 2015). The growth rate projection in the original ER is consistent with the following statistics from the time the 2006 forecast was generated:

1. On an annual basis and over the most recent 15 years, the U.S. economy was growing at a pace of 3.3% in 2006 when the peak demand and energy forecast was constructed.
2. From 2000 - 2006, the Virginia Gross State Product was growing at a rate of 3.9%, and the expected growth according to Moody's over the next 10 years was approximately 3% a year.
3. Residential Housing starts, a major driver for Dominion residential revenue class growth, was growing at a rate of 6% a year between 2000 and 2006.
4. Commercial employment, a major driver for Dominion commercial revenue class sales, was growing at a rate of 2.6% a year and according to Moody's, its expected growth for the next 10 years (2006 – 2015) was approximately 2%.

The severe recession, unforeseen by the majority of economic experts in 2005 – 2006, slowed energy growth significantly over 2009 – 2015. Additionally, the recession in 2009 lasted longer than recessions in recent decades, and the energy demand rebound following the recession was much less robust than any other recession recovery. All of these factors show that the forecast generated in 2006 was reasonable, considering the economic climate at the time.

Contrary to Ms. Noakes' concern, the need for power analysis in the ER (as originally submitted and as revised in 2013) are based on independent load forecasts prepared by PJM. As stated in the ER, "PJM is an independent regional transmission organization (RTO) responsible for operating the wholesale energy market in the largest centrally dispatched control area in North America." Dominion based its need for power analysis on data provided by PJM. This data includes historical integrated hourly loads and a forecasted energy growth rate for the Dominion Zone.

NUREG-1555 "directs the staff's review and assessment of the need for new baseload generating capacity." NUREG-1555 allows the NRC reviewer to "rely on the analysis in the applicant's ER (ER) and/or State or regional authorities' or Independent System Operators' (ISOs') analyses concerning the need for power and energy supply alternatives after ensuring that the analysis of the need for power and alternatives is reasonable and meets high quality standards."

NUREG-1555 provides four criteria to ensure the analysis of the need for power and alternatives is reasonable and meets high quality standards. It states:

> Affected States and/or regions, NERC reliability councils, and regional transmission organizations may prepare need-for-power evaluations for proposed generation and transmission facilities. The NRC will review the evaluation of the proposed facility and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty.

NUREG-1555 at 8.4-2. As documented in section 8.4.2 of the SEIS, the NRC evaluated the PJM/Dominion studies against these four criteria, and ultimately determined that the PJM studies and reports could be relied upon to help determine the reasonableness of Dominion's need for power analysis. Therefore, because Dominion utilized data from an independent source (PJM) to produce its analysis, and because the NRC reviewed the collective PJM reports against the criteria in NUREG-1555 and found that the studies and reports could be relied upon, the need for power analysis in the ER is considered "independently produced."

Ms. Noakes also asserts that adequate baseload capacity already exists. She utilizes a table provided by the Energy Information Administration (EIA) which states that Virginia has the capacity to produce 20,928 MW and assigns a capacity factor of 85% to obtain a power generation total for 2015. According to the EIA, baseload generating units generally operate 24 hours a day, year-round, except for maintenance outages. Peaking generators typically operate when hourly loads are at their highest. Intermediate generating units (cycling units) operate between baseload and peaking units, and typically vary their output to adapt as demand for electricity changes over the course of the day and year. In referencing the generation sources from the EIA table, Ms. Noakes has included generation not classified as baseload, which includes natural gas, petroleum, pumped storage, hydroelectric and wood generation. Furthermore, she is including generation for the entire state of Virginia, not just the Dominion Zone. As documented in Section 8.4 of the need for power analysis of the ER filed in 2013, the current baseload demand in the Dominion Zone has been estimated by reviewing 2012 historical PJM hourly loads for the Dominion Zone, sorting the 8760 hourly loads in declining order to create the load duration curve and selecting the 65th percentile hour load equal to 9,601 MW as the proxy for the 2012 baseload demand.

Ms. Noakes is concerned that insufficient consideration was given to alternatives not requiring new generating capacity, because the NRC Staff did not discuss the four such alternatives in Section 9.2.1 of the SEIS in combination with each other. It should be noted that Dominion took energy conservation into account by crediting 100 percent of Virginia's 10-percent conservation goal. *See* SEIS at 8-12. Dominion also explained that additional Demand Side Management programs (DSM) focus on reducing peak demand, and therefore do not affect the projected need for baseload capacity (*see id.* at 8-8). Thus, conservation and DSM were considered in establishing the baseline need (*id.* at 9-4), and evaluating these measures again as alternatives, alone or in combination with other alternatives, would essentially have double counted their potential impact. With respect to purchasing power from other suppliers, the ER and SEIS explain that imports are constrained by the transmission import capability and demand centers competing for the same electricity, and that any significant incremental imports would require major system upgrades or reliance on the already strained transmission system (with planned upgrades focused on meeting expected peak load supply requirements). *Id.* at 9-2, 9-3. Ms. Noakes does not dispute this conclusion or provide any explanation of what transmission upgrades, alone or in combination with other alternatives, could be implemented reasonably and economically to eliminate the projected need for base load power. With respect to extending the lives of existing plants, the SEIS explains that the units planned for retirement burn fuel oil and are not used to generate baseload power. *Id.* at 9-4. Thus, deferring their retirement, alone or in combination with other alternatives, would not reduce baseload demand. Finally, the SEIS explains that refurbishing retired plants would be economically difficult and not a reasonable alternative. Combining this alternative with other measures would not alter the conclusion.

Ms. Noakes also incorrectly suggests that eliminating transmission losses could eliminate half of the baseload generation of North Anna Unit 3. Ms. Noakes asserts that Virginia's transmission losses are approximately 10.1%. The EIA data to which Ms. Noakes refers do not support this assertion. In fact, in 2015, Dominion's transmission losses were 1.4% and distribution losses were 3.8%, totaling 5.2%. Dominion falls well below the EIA national average of losses of 6%. Dominion currently serves electric customers located in approximately 30,000 square miles across Virginia and North Carolina. Dominion currently has over 6,500 miles of transmission lines that operate at higher voltages (500, 230 and 115 kV). The backbone of Dominion's transmission system is rated at 500 kV, which is very efficient. Higher voltage transmission lines equate to lower transmission losses. Dominion currently has more than 57,000 miles of distribution lines across Virginia, North Carolina, and West Virginia. The majority of the distribution lines in Dominion's system have higher voltages (34.5 kV), which itself produces lower losses. Dominion is one of very few companies in the country that have a 34.5 kV distribution system. Dominion takes pride in doing everything it can to take all reasonable actions to minimize losses and considers its transmission and distribution system one of the best in the country, and is not aware of any reasonable measures to further reduce transmission losses that would alter the projected need for baseload capacity.

Ms. Noakes asserts that novel technologies have emerged since 2010 which should be discussed in the SEIS as alternatives to the construction and operation of a new nuclear unit. Dominion continually monitors and gathers information about potential and emerging utility-scale generation technologies from a mix of internal and external sources. Ms. Noakes refers to two emerging technologies, rail storage and salt water batteries. Rail storage and salt water batteries are not commercially viable technology capable of supplying baseload power at this time, or

likely to become so in the relatively near term. First, these technologies are still under development, have not been sufficiently demonstrated, and remain too expensive to address the intermittency of renewable generation. The Advanced Rail Energy System to which Ms. Noakes refers is at the prototype stage involving a 50 MW plant that will run seven trains through 5.5 miles of track up a slope rising 2000 feet in the Nevada desert. At this juncture, there is no information indicating that such a system is suitable for Virginia's topography or could be developed at a scale to displace 1500 MW(e) of baseload generation at any reasonable economic or environmental cost. Salt water batteries are also a startup technology deployed in small-scale projects, but they are large and have relatively short lives, and have not yet been developed and demonstrated for grid scale operation.

More importantly, rail storage and salt water batteries would not be a suitable substitute for 1500 MW of baseload generation and would be instead considered peaking units.

Solar and wind units only produce electricity when the sun is shining and the wind is blowing; therefore, energy output is variable and cannot be dispatched. Solar or wind coupled with storage such as batteries would be considered peaking, not baseload units. Solar generation has a capacity factor of approximately 25% and wind generation has a capacity factor of approximately 42%. Even with the addition of battery storage, the solar and wind units would not be considered baseload units due to the low capacity factors. As defined above, baseload units, which Dominion considers to include coal and nuclear units, should operate generally 24 hours a day, 365 days a year except for maintenance planned outages.

She also states that natural gas combined cycle units have achieved efficiency rates of 45%, and asserts that the higher efficiency compared with nuclear necessitates assuming fewer than three combined cycle units in section 9.2.2 of the ER. In fact, the ER already assumes the combined

cycle units have a heat rate of 7000 Btu/kW-hrs (*see* ER Table 9.2-8), which corresponds to an efficiency of nearly 49%. Further, her assertion that the relatively higher efficiency of natural gas combined-cycle turbines (45% in 2015 compared to 33% for nuclear) means that section 9.2.2.2 of the SEIS should have compared the 1500 MW(e) Unit 3 with less than three 500 MW(e) combined cycle units is incorrect. The higher thermodynamic efficiency is already reflected in the projected impacts from the combined cycle units producing equivalent capacity.

Dominion monitors utility-scale technology developments regularly for potential inclusion into the IRP. The IRP, filed annually and reviewed by the State Corporation Commission of Virginia, discusses emerging technologies and their potential application. To date, none of the emerging technologies identified in the IRP have enough potential to cause Dominion not to continue consideration of North Anna Unit 3 as a future generation option.

Question 24: Describe the Applicant's process for review of new and potentially significant information both between the ESP and COL applications and after the Final SEIS was published.

Response: The North Anna ESPA was submitted in September 2003. The NRC issued the FEIS in December 2006 and issued the North Anna ESP in November 2007. During the period from initial submittal of the ESPA to NRC issuance of the ESP, the ER in the ESPA was revised and updated as new information became available.

Dominion's new and significant information process in support of the COLA began with NRC issuance of the ESP FEIS. Since that time, it has remained an ongoing process which will continue to issuance of the COL. The new and significant process is described in Chapter 1 of the COLA ER.

During preparation of the COLA ER, Dominion implemented the new and significant process as follows:

- Dominion identified issues resolved in the FEIS. The NRC has established three significance levels for environmental impacts: SMALL, MODERATE, and LARGE. In general, one of these three significance levels was assigned to each impact evaluated and resolved in the FEIS. Environmental issues not resolved in the ESP proceeding were addressed in the COLA ER. The new and significant process was not utilized in those instances because the NRC had not yet evaluated the environmental impacts and assigned a significance level.
- Dominion performed a line-by-line review to identify key inputs from the FEIS and ESPA ER, and created a markup of each applicable section or chapter with each key input identified and numbered. Each numbered key input was listed in a new and significant screening table. These FEIS key inputs identify the main sources of information that were considered when determining if there could be new information potentially affecting a finding or conclusion regarding an environmental impact. The representations and assumptions relied upon by the NRC Staff during its review of the ESPA ER and development of the FEIS are identified in each section of the FEIS, and are also listed in FEIS Appendix J. In addition to the review of the FEIS for key inputs, the ESPA ER was also reviewed to identify any relevant key inputs for which new information is available that may bear on the FEIS impact evaluations.
- A review team consisting of subject matter experts, licensing specialists, and engineering and environmental personnel performed a screening of the FEIS and ESPA ER key inputs to determine whether there was new information available. Consideration was given to the potential for new information since time passage was a factor from FEIS completion to development of the COLA ER. The search for new information relied on discussions

with individuals knowledgeable on various aspects of the North Anna Unit 3 project, the North Anna Power Station site, and the region. The search also involved a review of project documentation such as the ESBWR DCD and ESBWR technical reports, review of ongoing North Anna Units 1 and 2 activities including environmental monitoring and updates to the site Virginia Pollutant Discharge Elimination System (VPDES) permit, consultations with Federal, State, and Local officials, and review of scientific literature and government agency websites. The results of the search were documented in the screening table.

- Dominion licensing and subject matter experts performed an evaluation of the new information documented in the screening table to determine if the new information was potentially significant. For new information to be "significant," it must be material to the issue being considered; that is, it must have the potential to affect the finding or conclusions of the NRC Staff's evaluation of the issue (72 Fed. Reg. 49,431). The results of the review, including the bases for the determination of significance, are documented and were audited by NRC Staff during the site environmental audit in April 2008 and subsequent environmental audits both on and off site. A description and evaluation of any new information determined to be potentially significant is provided in the COLA ER, submitted in November 2007.

The process Dominion has used for review of new and potentially significant information has not changed since the issuance of the Final SEIS, published in February 2010. Dominion has continued to use its subject matter experts, licensing specialists, and engineering and environmental personnel to identify new information that may affect key inputs in the prior environmental review, and to screen and evaluate this information as discussed above. However,

information and NRC conclusions found in the Final SEIS have been used to inform the ongoing new and significant screening and evaluation process. The NRC Staff performed periodic audits of documentation associated with Dominion's review process.

Respectfully submitted,

/Signed electronically by David R. Lewis/

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Dated: March 2, 2017

CERTIFICATION

I, Mark A. Giles, am responsible for the responses to the above questions. I certify that these answers were prepared by me or under my direction, and I adopt the answers as part of my sworn testimony in this proceeding. I hereby certify under penalty of perjury that the forgoing is true and complete to the best of my knowledge, information, and belief.

/Executed in Accord with 10 C.F.R. § 2.304(d)/
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Dated at Glen Allen, VA
this 2nd day of March, 2017

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Commission

In the Matter of	)	
	)	
Dominion Virginia Power	)	Docket No. 52-017-COL
	)	
North Anna Power Station, Unit 3	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Dominion Virginia Power's Responses to Pre-Hearing Questions, and accompanying Certification, have been served through the E-Filing system on the participants in the above-captioned proceeding, this 2nd day of March, 2017.

/Signed electronically by David R. Lewis/

David R. Lewis