From: Guzman, Richard
To: "Semancik, Jeffrey"
Cc: Mcnamara, Nancy; Tifft, Doug
Subject: [External_Sender] RE: Comments on Dominion LAR
Date: Friday, July 15, 2016 1:22:36 PM

Jeff,

The NRC staff is preparing to issue the following license amendments related to Millstone Power Station, Unit Nos. 2 and 3 (MPS2 and MPS3). A brief description of the license amendment request (LAR) is provided below. Additional information can be found in the licensee's submittal, as supplemented, which is also referenced below by ADAMS Accession number.

Thank you for providing your comments in your e-mail dated July 24, 2015, which were considered in the NRC staff's review. The staff's response to your comments are also inserted below following the license amendment description.

My current projection for issuance of the amendment is on or before July 29, 2016. I've also copied our Region State Liaison Officers for their awareness.

MPS Unit Nos. 2 and 3, License Amendment Request re: Removal of the Severe Line Outage Detection Special Protection System from the Offsite Power System

Application date: June 30, 2015, as supplemented by letters dated February 25 and June 29, 2016 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML15183A022, ML16061A007 and ML16189A076, respectively).

Brief Description of LAR: The amendment would revise the MPS2 and MPS3 Final Safety Analysis Reports (FSARs) to: 1) delete the information pertaining to the severe line outage detection (SLOD) special protection system (SPS), 2) update the description of the tower structures associated with the four offsite transmission lines feeding MPS, and 3) describe how the current offsite power source configuration and design satisfies the requirements of General Design Criteria (GDC)-17, "Electric Power Systems" and GDC-5, "Sharing of Structures, Systems, and Components." In addition, a new section, "Offsite Line Power Sources," would be added to the MPS2 and MPS3 technical requirements manual (TRM) supporting the licensing basis change. Specifically, with one offsite transmission line nonfunctional, the TRM requirement would allow 72 hours to restore the nonfunctional line with a provision to allow up to 7 days (for Lines 310, 348, and 383) or up to 14 days (for Line 371/364) if specific TRM action requirements are met.

Federal Register (FR) Notice: The LAR was published in the FR on October 13, 2015 (80 FR 61478): https://www.gpo.gov/fdsys/pkg/FR-2015-10-13/pdf/2015-25860.pdf with no comments or requests for hearing received.

State Official Comment

1. Dominion's submittal does not discuss the external risk of a common mode

failure that could result from brush fires along the 9-mile common ROW for the four transmission lines. Hot gases from a fire can ionize the air above a transmission line, causing the air to conduct electricity and short-circuit the conductors. Since the ROW contains heavy brush undergrowth, the "Avoidance of Plant Configurations that Could Degrade Defense-in-Depth Using Appropriate Mitigating Measures," should include some review not only of winds and hurricanes, but also brush conditions such as Red Flag warnings. Also, based upon the risk of lightening to induce brush fires, I do not believe it is appropriate to exclude lightening conditions from the weather assessment.

NRC staff response

The NRC staff views the concern of short-circuiting on conductors due to hot gases as a scenario that is enveloped by the loss of one transmission line or the simultaneous loss of two
transmission lines; this specific scenario was evaluated by the staff. While the staff noted that this scenario is not part of the NERC normal contingency, and is considered an extreme event, it issued an RAI for the licensee to address the technical concern involving two lines that are impacted by a single point vulnerability (for example, a single line at Hunts Brook Station dropping on the other lines resulting in a short-circuit condition of three lines nonfunctional) (DNC RAI response dated February 25, 2016, RAI-1, (ADAMS Accession no. ML16061A007). The staff determined that the licensee's supplemental responses adequately addressed its concerns:

The staff determined that the proposed revisions to the FSAR as supported with the TRM actions substantially reduce the potential for the simultaneous loss of two or more circuits due to a single event. The staff found that the proposed manual actions in lieu of the automatic protection afforded by the SLOD provide reasonable assurance that the potential for multiple circuit losses following a single line outage is reduced for the following reasons:

- The licensee modified the design for four 345 kV transmission lines leaving MPS. Specifically, the modification entailed relocating one of the two 345 kV transmission lines from each of the two existing DCTs onto a new SCT so that each 345 kV transmission line was on its own separate transmission tower. Thus, the modification minimizes the potential for the simultaneous loss of two circuits when one line is taken out of service for maintenance.

- The transmission towers which support the four 345 kV lines are designed to the National Electric Safety Code, Part C2 and provide reasonable assurance that the towers will withstand typical severe weather conditions.

- The licensee's administrative controls, transmission operating guides and procedures are established to minimize the potential for a severe event to impact grid reliability with one offsite line nonfunctional. The procedural controls require restoration of the nonfunctional 345 kV line to functional status prior to arrival of inclement weather or total station output to be reduced to = 1650 MW_e net.

Therefore, the NRC staff concluded the proposed changes to the offsite power system with the removal of SLOD SPS and changes to the UFSARs for MPS2 and MPS3 provide reasonable assurance of the continued availability of offsite power required to shut down and maintain the reactor in a safe condition after an anticipated operational occurrence or a postulated design-basis accident. Additionally, the staff concludes that with the proposed changes, the licensee would continue to meet the requirements of GDC-5 and GDC-17.

State Official Comment

2. Line outage review in the submittal is limited to the specific transmission path. There is no industry operating experience review. For example, one of the events leading to the August 14, 2003 blackout identified by the investigation task force was the loss of the Stuart – Atlanta 345 kV line (part of the transmission pathway from southwestern Ohio into northern Ohio) that disconnected from the system due to a brush fire under a portion of the line.

NRC staff response

The NRC staff considered in its evaluation of the proposed license amendment, the operating experience applicable to MPS and the station's adjacent transmission path. The staff noted that based on operating experience of transmission line disturbances or line failures for the four offsite transmission lines from 2005 to May 2015, forced line outages from 2005 to 2014, and planned transmission line outages from 2009 to May 2015, there have been no contingency events at Hunts Brook Junction. In the staff's RAI discussed above in comment no. 1, the staff considered, as identified by the licensee's walkdown, the configuration of the transmission lines at Hunts Brook Junction as a primary area of concern in that Lines 383 or 310 cross over line 371/364 (Line 348 runs to the west of the crossover). Specifically, with transmission line 348, 310, or 383 nonfunctional, the possibility exists for either Line 383 or 310 to drop on Line 371/364 (and the result of three transmission lines nonfunctional). The staff also noted that along with no contingency events at Hunts Brook Junction, there has been no instability or LOOP events that have occurred due to transmission element failures at Hunts Brook Junction.

Additionally, the licensee confirmed that the grid operator performs assessments using NERC reliability standard TPL-001-4, NPCC Directory #1, ISO-New England Planning Procedure 3,
ISO-New England Operating Procedure OP-19 and has concluded that the system will remain stable following the most severe of normal contingencies such as a permanent three-phase
fault on any generator, transmission circuit, transformer, or bus section with normal fault clearing. Therefore, the NRC staff concluded the proposed changes to the offsite power system
with the removal of SLOD SPS and changes to the UFSARs for MPS2 and MPS3 provide reasonable assurance of the continued availability of offsite power required to shut down and
maintain the reactor in a safe condition after an anticipated operational occurrence or a postulated design-basis accident. Additionally, the staff concludes that with the proposed changes, the
licensee would continue to meet the requirements of GDC-5 and GDC-17.

State Official Comment

3. The license submittal does not include a plant specific PRA basis to control the 14-day AOT subject to 50.59 in the TRM vice controlling it as a Technical Specification Limiting Condition for Operation pursuant to 50.36. Following the May 2014 LOOP, the NRC estimated "CCDPs for Unit 2 in the range of one in 66,000 to 120,000 for such events, and for Unit 3 one in 74,000 to 137,000, for such events. In both cases, the assumption was that with SLOD removed and one transmission line out-of-service, Dominion should have implemented the combined-unit output limitations such that given the event of May 25, 2014, neither unit would have experienced a LOOP." I [believe] that LOOP is the highest risk contributor for both Units 2 and 3. With the PRA impact of a loss of offsite power at Millstone, especially in light of the occurrence of the event of concern, it seems that there should be a quantitative risk assessment for why this LCO does not meet criteria 4 of 10 CFR 50.36(c)(2)(ii)(D).

NRC staff response

The NRC staff acknowledges that the LOOP event is an important risk contributor to consider for both MPS2 and MPS3. However, while the licensee's PRAs for MPS2 and MPS3 do not specifically model the four offsite power transmission lines, LOOP frequency and consequential LOOP probability values are applied in the MPS PRA models. As stated by the licensee in its LAR, the values are calculated based on industry LOOP events occurring within a certain time period. The May 25, 2014, event at MPS is the only LOOP event to affect all operating units on site or the only instance during which a loss of three transmission lines occurred in the station's history. MPS3 experienced a LOOP event during its refueling outage in 2007; however, it did not impact the other operating units (i.e., MPS2 remained in operation). The cause of the 2007 transmission line-related event was due to a switchyard breaker being inadvertently opened by the transmission system operator. The licensee stated that with only one LOOP event occurring over a relatively extended period and the cause of that event addressed (i.e., the protective relaying element that caused the trip was removed), the May 2014 event is not considered representative of the risk impact associated with the removal of one transmission line from service. The NRC staff considers the licensee's assessment as a reasonable basis in making the determination that the site specific configuration involving one transmission line out-of-service for maintenance are not viewed as significant to public health and safety in terms of the 50.36(c)(ii) criteria.

Additionally, per 10 CFR 50.36(c)(2)(i), LCOs are the lowest functional capability or performance levels of equipment required for the safe operation of the facility. Both units are permitted by Technical Specifications, to have any power source out of service for 72 hours. The 72-hour allowed outage time is based in part on MPS having multiple sources of power. While offsite power is the preferred power source for plant equipment, it is usually not the safety-related source used to mitigate accidents in the accident analysis. TSs are derived from the analysis; MPS2 and MPS3 each have two independent safety grade emergency diesel generators that automatically start and load following an interruption of power to their respective 4 kV emergency buses. No TS requirements for the EDGs are being changed as part of the proposed amendment and the associated equipment is expected to function as designed for accident mitigation and recovery. The EDGs are the credited source of power that meet 10 CFR 50.36(c)(2)(ii)(C).

The proposed TRM action requirements limit any transmission line outage to 72 hours or when instituting additional measures, 7 days with transmission lines 310, 348, and 383 nonfunctional or 14 days with transmission line 371/364 nonfunctional. Part of the additional measures would require the licensee to limit MPS power output from the site, when adverse weather is predicted during a simultaneous single transmission line outage, to = 1650 MW_e net as a conservative measure to maintain grid stability. The proposed TRM actions do not involve adverse impact to the primary success path associated with offsite power availability. With one offsite line nonfunctional, offsite power remains available and the existing analyses remain bounding.

The NRC staff also reviewed the proposed MPS actions for inclusion into the TRM along with the licensee's evaluation that determined that the requirements did not meet the threshold for inclusion into the TS. Additionally, the staff evaluated the proposed changes against the guidance in NUREGs 1432, Rev. 4 and 1431, Rev. 4 for MPS2 and MPS3, respectively. The NRC staff found that the proposed TRM requirements did not meet any of the criteria and there were no similar TS LCOs in the guidance documents. The staff noted that requirements associated with offsite power systems not being included in the TSs is consistent with NUREG-1431 and NUREG-1432 for MPS2 and MPS3, respectively. The staff found the licensee's evaluation for four criteria as acceptable; that is, the proposed TRM action requirements for offsite line power sources do not meet the criteria for inclusion into the TSs. Therefore, based on the above evaluation, the staff concluded that there is reasonable assurance that the requirements of 10 CFR 50.36 will continue to be met.

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From: Semancik, Jeffrey
Sent: Friday, July 24, 2015 4:32 PM
To: Richard Guzman (Richard.Guzman@nrc.gov)
Subject: Comments on Dominion LAR

Richard,

I received a copy of Dominion's License Amendment Request (LAR) Serial 15-297 (June 30, 2015) for removal of Severe Line Outage Detection from the Offsite Power System. I reviewed the LAR and had some comments for your consideration. I understand that you have just received it and are in the review process, but, since this involves GDC17 compliance and I recognize that is a complicated technical subject, I wanted to forward questions early so I don't cause any delays in the process.

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Please let me know if you have any questions or if I should be using another method to forward my comments. I would appreciate feedback on my comments.

Thanks,

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