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PSEG
Nuclear LLC

10 CFR 50.90

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LAR S18-02
OCT 20 2018

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Salem Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. DPR-70 and DPR-75
NRC Docket Nos. 50-272 and 50-311

Subject: Response to Request for Additional Information, Re: License Amendment Request: Inverter Allowed Outage Time (AOT) Extension

References:

1. PSEG letter to NRC, "License Amendment Request: Vital Instrument Bus Inverter Allowed Outage Time (AOT) Extension," dated May 16, 2018 (ADAMS Accession No. ML18136A866)
2. NRC email to PSEG, "Salem 1 and 2 - Final RAI from PRA Branch RE: Inverter AOT Extension," (EPID: L-2018-LLA-0140) dated September 21, 2018 (ADAMS Accession No. ML18267A171)

In the Reference 1 letter, PSEG Nuclear LLC (PSEG) submitted a license amendment request for Salem Generating Station Unit 1 and Unit 2. The proposed amendment would increase the Vital Instrument Bus (VIB) Inverters allowed outage time (AOT) from 24 hours for the A, B and C inverters to 7 days and from 72 hours for the D inverter to 7 days. In Reference 2, the Nuclear Regulatory Commission (NRC) requested PSEG to provide additional information in order to evaluate the proposed License Amendment Request to revise Technical Specifications. The response due date was subsequently extended to October 24, 2018 at PSEG's request.

Attachment 1 to this letter provides a restatement of the RAI questions followed by our responses. PSEG has determined that the information provided in this submittal does not alter the conclusions reached in the 10 CFR 50.92 no significant hazards determination previously submitted. In addition, the information provided in this submittal does not affect the bases for concluding that neither an environmental impact statement nor an environmental assessment needs to be prepared in connection with the proposed amendment.

There are no regulatory commitments contained in this letter.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), PSEG is providing a copy of this response, with attachments, to the designated State of New Jersey Official.

Should you have any questions regarding this submittal, please contact Mr. Lee Marabella at 856-339-1208.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 10/20/18
(Date)

Sincerely,

Charles V. McFeaters
Site Vice President
Salem Generating Station

Attachments:

1. Response to Request for Additional Information - License Amendment Request to Revise Technical Specification 3.8.2.1 Regarding Alternating Current Inverters

cc: Administrator, Region I, NRC
Mr. J. Kim, Project Manager, NRC
NRC Senior Resident Inspector, Salem
Mr. P. Mulligan, Chief, NJBNE
Salem Commitment Tracking Coordinator
Corporate Commitment Tracking Coordinator

Attachment 1

Response to Request for Additional Information - License Amendment Request to Revise Technical Specification 3.8.2.1 Regarding Alternating Current Inverters

By letter dated May 16, 2018 (Agencywide Documents Access management System (ADAMS) Accession No. ML18136A866), PSEG Nuclear LLC (PSEG, the licensee), requested an amendment to Renewed Facility Operating License Nos. DPR-70 and DPR-75 for Salem Generating Station (Salem) Units 1 and 2. This license amendment request proposes changes to Technical Specification (TS) 3.8.2.1, "A. C. Distribution - Operating." The proposed change would increase the Vital Instrument Bus (VIB) Inverters allowed outage time (AOT) from 24 hours for the A, B and C inverters to 7 days and from 72 hours for the D inverter to 7 days. Below is a restatement of the questions followed by our responses.

Question 1 (APLA RAI-1)

In order to ensure efficiency in its reviews and prevent duplicate reviews of a licensee's PRA technical acceptability, the NRC staff may utilize PRA information from the licensee's previous risk-informed submittals. In the course of its review for this LAR, the staff utilized information from the licensee's application for Salem containment fan cooler unit AOT extension dated March 6, 2017 (ADAMS Accession Number ML17065A241), as supplemented by letters dated May 4, 2017 (ADAMS Accession Number ML17125A051) and September 14, 2017 (ADAMS Accession Number ML17257A439). The method used by the licensee for estimating core damage frequency (ΔCDF) for fire and seismic events in the supplemental letter dated May 4, 2017, differs from the method used in the current LAR dated May 16, 2018 (ADAMS Accession Number ML18136A866). The NRC staff performed a confirmatory calculation based on the method used in the May 4, 2017 letter. The resulting value for ΔCDF for fires corresponded to Region II RG 1.74 acceptance criteria. As a result, the licensee's conclusion in Section 3.2.3.2 of the current LAR that since the change in CDF is negligible, the large early release frequency (LERF) impact will also be negligible would not be valid per the confirmatory calculation, as a change in CDF corresponding to Region II of RG 1.74 is not considered negligible.

Alternate Fire Event Calculations for Salem Inverter D

Calculation of $\Delta CDF_{surrogate}$:

$\Delta CDF_{surrogate} = F_{IE\text{-}F} \times UA_{INV} \times P_{BU} \times (T_{AOT}/T_{CYC}) = 2.51E\text{-}06$ / reactor-year

where:

$F_{IE\text{-}F}$ = fire initiating event frequency = 4.62E-01

UA_{INV} = Unavailability of inverter D = 1.0

P_{BU} = Probability of backup power failure = 2.83E-04

T_{AOT} = AOT duration = 7 days

T_{CYC} = cycle duration = 365 days

T_{AOT}/T_{CYC} = Fractional Unavailability

Per the NRC alternate calculations above, the values determined for $\Delta CDF_{surrogate}$ correspond to Region II RG 1.74 acceptance criteria. This is a less conservative result than that reported in Section 3.2.3.2 of the licensee's LAR dated May 16, 2018.

RAI-1

Please provide a discussion explaining the use of the two different calculation methods and the rationale for the acceptability of the fire PRA approach used in the LAR dated May 16, 2018, as opposed to the method used in the letter dated May 4, 2017, and the basis for the determination that this approach is sufficiently conservative to support the proposed inverter AOT extension. In addition, provide an evaluation of the ΔLERF from fire events.

Response:

The two different calculations are created specifically for each of the two situations being analyzed (i.e., CFCUs and inverters). Both calculations use similar overall approaches, but do have some differences to reflect the different functions and operational characteristics of the different components. In each case, the calculation is provided as a surrogate calculation to provide a bounding value for fire ΔCDF/ΔLERF. The overall approach is to combine the following factors into a surrogate calculation:

- Frequency of fire events
- Probability that other components are unavailable that create the need for the analyzed component
- Probability that the analyzed component is unavailable

For the two different calculations, all three of these values are slightly different. Each difference is described here.

Frequency of fire events

The inverter calculation uses a more recent estimation of the overall plant fire ignition frequencies based on the current work-in-progress fire PRA, which uses fire ignition frequencies calculated from Supplement 1 of NUREG/CR-6850 (FAQ 08-0048) and NUREG-2169, as stated in the LAR. The value used for the inverter calculation is actually much greater than used for the CFCU (0.462 versus 0.05), and includes the very conservative assumption discussed in the LAR that every fire scenario is assumed to impact all but one inverter (and its backup power source). Note that the frequency of fire events for the CFCU calculation uses a reduced frequency based on “one out of four fires would lead to a plant trip, and fail all but one train of safety-related auxiliary feed water (AFW), and all but one train of containment spray system (CSS).”

Probability that other components are unavailable that create the need for the analyzed component

Because the inverters and CFCUs provide different functions, the situations which create the need for the analyzed components are different. For CFCUs, this probability represents a scenario with the concurrent unavailability of multiple other decay heat removal systems which creates the scenario in which the CFCUs are relied upon as the remaining containment heat removal system. For an inverter, the inverter is the primary power supply to its train, but other components (alternate 230 VAC power sources) provide a redundant function to the inverter, so the failure probabilities of these backup components are quantified from the FPIE PRA to provide the probability value for this term in the equation.

Probability that the analyzed component is unavailable

This difference in the calculations is due to the different expected operating conditions for the CFCUs and inverters, and also appears to be the difference in the NRC calculation.

For the surrogate CFCU calculation, the newly requested condition (i.e., increased CFCU AOT) is expected to occur and the extended outage times are expected to be utilized by the plant on an assumed frequency of three times per operating cycle, so this frequency was used to calculate the expected increased unavailability for the CFCUs, represented by the "fractional exposure time" in the CFCU LAR supplement. This approach did not take credit for the baseline unavailability but instead assumed that the entire newly assumed unavailability would contribute to the ΔCDF and ΔLERF. The very conservative expectation is designed to bound the maximum maintenance activity (preventive and corrective), and is not based on the CFCU failure rate.

For the surrogate inverter calculations, since the inverters are not expected to be voluntarily removed from service on a regular basis, a different approach is used to estimate the increase in unavailability. The approach in the LAR calculated an increased unavailability of an inverter by assuming that the same occurrence rate of unavailability would remain, but that the duration of each unavailability period would increase by a factor equal to the increase in allowed outage time (i.e., a factor of 7 for inverters 1A/B/C and a factor of 2.33 for inverter 1D). This causes the formula for the calculation to appear different from the CFCU calculation, but the overall concept is the same, in that the inverter calculation refers to this value as an increase in unavailability, while the CFCU calculation refers to it as a fractional exposure time, both of which represent the total amount of time the components are expected to be unavailable. The correlation between the formula from the CFCU LAR and the formula from the Inverter LAR is shown in this figure:

CFCU ΔCDF Surrogate Calculation

Concurrent Unavailability of the Following: (1) Single CSS Train in Recirculation (2) Turbine Driven AFW Pump (3) Unavailability of 4th AFW Pump	Site-Wide Fire Ignition Frequency (1/yr)	Unavailability of CFCUs	Fractional Exposure Time	Surrogate ΔCDF (1/yr)
4.56E-05	0.05	1.0	7.67E-02	1.7E-07

$$\Delta CDF = F_{IE\text{-}F} \times \Delta UA_{INV} \times P_{BU}$$

Inverter ΔCDF Surrogate Calculation

The inverter calculation could be modified to use a similar formula as the CFCU calculation, such that:

$\Delta CDF = F_{IE\text{-}F} \times UA_{INV} \times \text{Fractional Exposure Time} \times P_{BU}$

which would produce the same results as the LAR, since the fractional exposure time is the expected amount of time each inverter is out of service, if the existing unavailability under the current license conditions is not included. The matching results are shown for the most conservative case in the Inverter LAR (Inverter A or C):

ΔCDF = 0.462 x 1.0 x 1.20E-3 x 1.53E-4 = 8.48E-8

In the NRC calculation represented in APLA RAI-1 above, the different result appears to be due to a different assumption of the expected amount of time the inverter will be unavailable, called the fractional unavailability. The NRC calculation assumes that an inverter will be unavailable for seven days each year. While that amount of unavailability could theoretically occur, it is inconsistent with planned plant operation, and such an assumption is not directly tied to the extended outage time since multiple outages can occur so long as a single outage does not exceed the allowed outage time The CFCU calculation assumed three occurrences of the maximum outage time per 18-month cycle. For this calculation, we multiplied the existing failure rate by the requested outage time. This better represents the intent of PSEG to use the extended allowed outage time to troubleshoot and repair emergent failures. The total outage time during a year could be theoretically more or less than this seven days, under both current and requested license conditions. The approach used in the LAR assumes the existing PRA unavailability is increased by a factor equal to the extension factor and more fairly represents expected inverter unavailability based on historic and planned plant operation. This bounds the risk increase because other conservatisms involved in the calculation such as the overall plant fire ignition frequency and the underlying assumption that every maintenance action uses the entire AOT.

Since an inverter is not expected to be removed for maintenance unless it has failed, another approach would be to develop the unavailability or fractional exposure time based on the expected failure rates of the inverters. We can use the failure rates for inverters present in the Salem PRA model (5.6E-6 failures/hr) to estimate the number of expected failures per year that would allow the use of the increased outage time. Then assuming a seven-day outage for every inverter failure, the average unavailability of an inverter under the increased AOT would be:

Q = 5.6E-6 failures/hr * 7 days / failure * 24 hr /day = 9.41E-4

In the NRC equation for $\underline{\Delta CDF}_{surrogate}$, this value captures the purpose of the UA_{INV} and (T_{AOT}/T_{CYC}) terms, so that

ΔCDF = 0.462/yr * 9.41E-4 * 2.83E-4 = 1.23 E-7/yr

Assuming no CDF from the base case inverter unavailability, the maximum ΔCDF is 1.23E-7/yr, with the assumption that all fires cause the worst-case failures of all other trains of inverters without failing the one inverter train with the worst-case backup system (inverter 1D). Within the uncertainties of these surrogate ΔCDF calculations, this number is not essentially different from the calculation in the LAR that estimated 8.48E-8/yr.

This new estimated value (1.23E-7/yr) is within the Region III area of RG 1.174 for ΔCDF, and would decrease below that level if any of the conservatisms were reduced or removed. For LERF, while this value is within Region II if all ΔCDF is assumed to also be ΔLERF, reduction or removal of any of the conservatisms would decrease the maximum possible impact from Region II to Region III. One such reduction would be the use of a reduced fire ignition frequency that accounts for the likelihood of reactor trip and other necessary failures, similar to what was accepted for the CFCU calculation. Another reduction comes from analytic experience. Typically, for large dry containments and scenarios other than steam generator tube rupture or interfacing system LOCA, the LERF is much lower than the CDF. Either reduction would reduce the maximum estimated ΔLERF into Region III as well. Therefore, either calculation for both ΔCDF and ΔLERF due to fire is sufficiently conservative to support the proposed inverter AOT extension.

In summary, the estimated maximum ΔCDF due to fire for the inverter extension is shown to be within the Region III area of RG 1.174, and the ΔLERF due to fire is expected be in the Region III area if the intentional conservatisms in all of the calculations are considered. The differences between the inverter calculation and the CFCU calculation are driven by the different operating conditions for the different components. PSEG's approach is to not schedule any online PM outage for inverters. The CFCU calculation assumes a number of intentional entries into the CFCU outage condition, while the inverter calculation assumes that an outage condition would only occur following an unexpected failure.

Question 2 (APLA RAI-2)

The entry for item (I) in Table A-7 of Attachment 2 to the LAR dated May 16, 2018, notes that the Salem PRA Model of Record (MOR) (SA115A) was only completed for Salem Unit 1 and it relies on Unit 2 equipment for certain support functions.

RAI-2

Please provide justification that the cross-unit support functions, as well as the asymmetries, in the Salem PRA MOR (SA115A) are adequately accounted for such that application to Salem Unit 2 is appropriate.

Response:

The following list provides a summary of the major differences noted between the two Salem units:

- The Service Water (SW) air-operated valves (AOVs) that service the #12A and #12B Component Cooling Water (CCW) heat exchangers for Unit 1 require a control air dependency for successful operation whereas the #22 SW AOVs in Unit 2 do not. The equipment differences are small and the scenarios affected are not related to the inverters and their function to supply 115v AC power.
- The power dependencies for the SW pumps and associated motor operated valves (MOVs) are not symmetric between the two units. For example, the 4kV AC vital bus A on Unit 1 powers the 15 and 16 SW pumps, while the A vital bus on Unit 2 powers the 21 and 22 SW pumps. The vital bus power supplies are symmetric on each unit, so there is no risk difference.
- The Unit 2 chemical and volume control system (CVCS) pumps do not require CCW cooling for their mechanical seals while the Unit 1 CVCS pumps do during normal operation. However, this particular CCW dependency is not modeled in the PRA since it is not required for successful operation of the CVCS pumps during the injection phase of an accident condition since water from the refueling water storage tank (RWST) is relatively cool.
- The three Station Air Compressors (SACs) and Instrument Air system are shared between the two units, with SACs #1 and #3 powered from Unit 1 Group buses and SAC

2 powered from a Unit 2 Group bus. All three SACs are physically located in the Unit 1 Turbine Building on the 100’ elevation. The SACs are not credited in LOOP scenarios and the group buses are highly reliable in non-LOOP transient and LOCA scenarios.

- The four Demineralized Water (DM) pumps are also physically located in the Unit 1 Turbine Building on the 100’ elevation and provide DM water for both Unit 1 and Unit 2. The power supplies are such that the #1 and #3 pumps are powered from a Unit 1 Group bus while the #2 pump is powered from a Unit 2 Group bus. The Auxiliary DM pump is powered from a Unit 1 vital bus. These pumps are important to refill the AFW storage tank late in many scenarios; however the diverse power supplies to pumps and diverse water sources for steam generator (SG) cooling ensure that this arrangement does not affect risk calculations.
- The Station Blackout (SBO) Air Compressor is located in the yard in close proximity to the Unit 2 Turbine Building and services the Control Air system for both units when required via a connection on the discharge side of the Unit 2 Emergency Control Air Compressor. This defense-in-depth feature relies on long term human actions that are appropriate for either plant’s risk profile.
- Unit 2 contains a semi-automatic transfer of suction from the RWST to the containment sump, whereas Unit 1 requires manual manipulations based on visual indication in the control room to perform a swap over to sump recirculation. The Unit 1 configuration is modeled in the PRA, which is conservative with regard to the Unit 2 configuration because the probability of human failure is lower on Unit 2.

Operations personnel are trained such that, with the exception of the semi-automatic transfer of sump suction, no differences would exist with the Human Reliability Analysis (HRA) between the two units.

The above noted differences between the two units are small and/or conservative, so model refinement is necessary to account for these unit differences.

The following summarizes the Unit 2 support systems that have been modeled in the PRA for Unit 1. Since a fully developed Unit 2 model with electrical power dependencies that includes logic for the Unit 2 emergency diesel generators was not available, power dependencies were developed to account for scenario-specific vital bus unavailability.

- The Unit 1 PRA model logic for SW includes the ability to cross-tie the Unit 2 SW system for recovery of the Unit 1 SW headers should the Unit 1 SW supply become unavailable. An event representing the unavailability of the Unit 2 SW system was used as a surrogate event to represent Unit 2 SW dependencies.
- The control room ventilation model logic for Unit 1 also makes use of Unit 2 ventilation fans and other room cooling equipment, with electrical dependencies that include logic for specific Unit 2 bus failures. Electrical failures that include dependence on the Unit 2 emergency AC power sources were not modeled since a full Unit 2 PRA model was not available for use. However, non-vital electrical dependencies were modeled as being dependent on offsite power sources.
- The Unit 1 to Unit 2 CVCS cross-tie for long-term use of Reactor Coolant Pump (RCP) seal injection was modeled to support those scenarios in which the Unit 1 RCP seal injection capability was lost and long-term recovery via use of this cross-tie would be viable.

As noted above for the Unit 1 to Unit 2 differences, the use of these Unit 2 support dependencies are adequately addressed by the Unit 1 model to fairly represent the as-built as-operated dual unit site with a single unit PRA model.