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U.S. Nuclear Regulatory Commission
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Salem Generating Station, Unit 2
Renewed Facility Operating License No. DPR-75
NRC Docket No. 50-311

Subject: Request for Enforcement Discretion for Salem Unit 2 Offsite Alternating Current (AC) Sources

PSEG Nuclear (PSEG) at Salem Generating Station, Unit 2 is requesting enforcement discretion from compliance with Salem Technical Specification (TS) Section 3.8.1, "AC Sources - Operating."

24 Station Power Transformer (SPT) was declared inoperable at 1356 hours on February 13, 2014. The 24 SPT was removed from service as required by guidance contained in an Adverse Condition Monitoring and Contingency Plan. Transformer combustible gas levels indicated an active thermal fault. PSEG is preparing to replace the existing 24 SPT with a like-for-like spare.

TS 3.8.1.1 Action a.3 for Salem Unit 2 requires restoration of the 24 SPT to Operable status within 72 hours or be in at least Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours. PSEG expects to have the 24 SPT fully operable by February 22, 2014, at 1356 hours.

Based on current projections, this extension will allow completion of replacement, testing and return of the 24 SPT to service. Therefore, without enforcement discretion for a period of 6 days, at 1356 hours on February 16, 2014, Salem Unit 2 will commence a unit shutdown to comply with the requirements of TS 3.8.1.1, Action a.3.

The attached enclosure provides the information necessary for approval of the requested enforcement discretion.

This information was discussed with representatives of the NRC on February 14 and 15, 2014 with subsequent approval being verbally granted by the NRC at 2115 hours on February 15, 2014.

There are no new commitments in this letter.

If there are any questions, please contact Kevin Chambliss at 856-339-1792

Respectfully,

John F. Perry
Salem Site Vice-President

Enclosure: Request for Enforcement Discretion for Technical Specification 3.8.1 "AC Sources – Operating".

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ENCLOSURE

Salem Generating Station, Unit 2

Docket No. 50-311

Renewed Facility Operating License No. DPR-75

Request for Enforcement Discretion for Technical Specification Section 3.8.1, "AC Sources - Operating."

Request for Enforcement Discretion for Technical Specification (TS) Section 3.8.1, "AC Sources - Operating."

a) Type of NOED, NOED criteria satisfied and how the criteria are satisfied.

A regular NOED to avoid an unnecessary transient as a result of compliance with the TS is being submitted in accordance with NOED Criterion 03.03 (b) since compliance with the TS would involve an unnecessary shutdown of the unit at the end of core life without a corresponding health and safety benefit.

b) TS or license condition that will be violated.

PSEG Nuclear, LLC (PSEG), Salem Unit 2 is requesting enforcement discretion from TS Section 3.8.1, "AC Sources – Operating". TS 3.8.1.1 Action a.3 for Salem Unit 2 requires restoration of the inoperable offsite circuit to operable status within 72 hours or be in at least Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours. This request for enforcement discretion is being made to avoid an unnecessary plant transient and shutdown as the result of compliance with TS 3.8.1.1, Action a.3.

PSEG expects to have the 24 Station Power Transformer (SPT) fully operable by February 22, 2014, at 1356 hours.

Based on current projections, this extension will allow completion of replacement, testing and returning to service the 24 SPT. Therefore, without enforcement discretion for a period of an additional 6 days, at 1356 hours on February 16, 2014, Salem Unit 2 will commence a unit shutdown to comply with the requirements of TS 3.8.1.1, Action a.3.

c) Description of the circumstances, including: likely causes; the need for prompt action; the action taken to avoid the need for a NOED; and any relevant historical events.

At the time of this request, Salem Unit 1 and Unit 2 are operating in Mode 1 (Power Operations),at approximately 100% power. The Unit 2 24 SPT was declared inoperable at 1356 hours on February 13, 2014 as a result of indications of an internal thermal fault detected by the online dissolved gas in oil monitor.

The combustible gassing rate was greater than 200 ppm per day (mainly ethylene gas accompanied by methane, ethane and acetylene). The gassing occurred for a period of approximately 14 hours before the transformer was removed from service. IEEE Std C57.104-2008, “IEEE Guide for the Interpretation of Gases Generated in Oil Immersed Transformers” recommends considering removal of the transformer from service when the gassing rate for all combustible gasses combined is greater than 30 ppm per day.

The likely cause of the condition is due to internal thermal fault in conductor connections or electrical contacts. Conductor connections exist at the high and low voltage bushings, the core ground, and at the no-load, fixed tap changer. The only contacts inside the transformer are at the no-load, fixed tap changer.

Repair of the condition requires entry into the transformer or replacement of the transformer. Oil processing times required for entry option would exceed the time required to replace the transformer.

One previous gassing event occurred on this transformer in September of 2013. In that case there was an initial increase in combustible gas levels, however the gassing rate immediately lowered and the gas levels in the transformer were stable for the period from September of 2013 until February 13, 2014.

Since the September, 2013 gassing event signified degradation during this operating cycle, an adverse condition monitoring plan was put in place for monitoring and trending key parameters including combustible gassing rate. The condition of the 24 SPT had been relatively steady based on review of trending of levels of combustible gassing rate. The transformer's performance was not expected to substantially degrade prior to the scheduled replacement in the upcoming spring 2014 refueling outage. However, an unexpected sudden step increase of combustible gasses with a steep upward trend in the gassing rate, required plant operators to remove it from service. Repair and replacement of the 24 SPT will require more time than allowed by the 72 hour Action time of TS 3.8.1.1, Action a.3.

Enforcement discretion is requested to allow completion of replacement, testing and return to service of the 24 SPT. Approval of the proposed enforcement discretion would avoid an unnecessary unit shutdown without a corresponding health and safety benefit.

d) Cause of the situation that has led to the NOED request.

On February 13, 2014 the 24 SPT experienced a step change in the amount of dissolved gasses detected in the transformer oil. The dissolved gasses in the oil were primarily ethylene, methane and acetylene. No significant generation of carbon-monoxide or carbon dioxide occurred. This indicates a high temperature thermal fault, internal to the transformer, in an area of the transformer away from paper insulation. Based on the rapid development of the fault, the likely location is at a bolted connection or contact within the main transformer tank.

External causes of the thermal condition in the transformer (overload or short circuit) have been excluded based on the lack of actuation of any protective relaying and normal overall transformer temperature.

Since the high level of dissolved gasses is attributed to an internal condition of the existing 24 SPT, replacement of the transformer will resolve this condition.

e) Proposed course of action to resolve the situation until the situation no longer warrants the NOED.

PSEG has determined that there is minimal safety consequence in extending the Allowed Outage Time of TS Section 3.8.1.1, Action a.3. for 6 days. The additional 6 days will allow for de-energizing, tagging, disconnecting, rigging and removing the existing 24 SPT. The spare SPT will be transported to the transformer pad, installed, connected, and tested. Following successful testing, tags and grounding will be removed and the SPT will be energized and returned to service.

f) Why the resolution does not result in a different unnecessary transient.

Replacement of the 24 SPT will not result in a different unnecessary transient. No lifting activities will take place over safety-related equipment. The rigging of the old and new like-for-like SPT will take place while they are de-energized and disconnected. Removal and replacement activities will be monitored to ensure no vital plant equipment will be affected by the rigging, transport and replacement of the SPT.

g) Why there is not enough time to process an emergency TS or license amendment or that a license amendment is not needed.

The Unit 2, 24 SPT was declared inoperable at 1356 hours on February 13, 2014 as a result of indications of an internal thermal fault detected by the online dissolved gas in oil monitor. TS Section 3.8.1.1, Action a.3 requires restoration of the inoperable offsite circuit to operable status within 72 hours or be in at least Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours. The duration of 72 hours prior to commencing unit shutdown does not allow time to process an emergency license amendment.

h) The condition and operational status of the plant including safety-related equipment out of service or otherwise inoperable and nonsafety-related equipment that is degraded or out of service that may have risk significance and that may increase the probability of a plant transient or may complicate the recovery from a transient or may be used to mitigate the concern.

The Salem Unit 2 Class 1E AC Electrical Power Distribution System consists of two independent offsite power sources via 23 and 24 SPTs and the onsite standby Emergency Diesel Generators (EDGs) 2A, 2B, and 2C. The design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems. The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has access to two offsite power supplies. Each load group can also be connected to a single EDG.

During the period of the proposed enforcement discretion, Unit 2 will be in Mode 1 with one of two redundant offsite power sources (24 SPT) unavailable. The availability of one offsite power source, coupled with the three operable EDGs, continues to provide adequate assurance of the capability to provide power to the ESF systems for Unit 2 under postulated accident conditions.

i) Specific period for the NOED, including justification for the duration of the noncompliance.

It is requested that the allowed outage time for the 24 SPT inoperability be extended from 72 hours to 9 days. PSEG has determined that there is minimal safety consequence associated with extending the allowed outage time for the 24 SPT replacement. The additional 6 days will allow for de-energizing, tagging, disconnecting, rigging and removing the existing 24 SPT. The spare SPT will be transported to the transformer pad, installed, connected, and tested. Following successful testing, tags and grounding will be removed and the SPT will be energized and returned to service.

j) Compensatory measures the plant has both taken and will take to reduce the risk associated with the specified configuration.

If there is an emergent failure of any equipment in a protected area, or of any equipment that is listed in the PRA risk assessment, or any equipment that is considered for defense in depth, PSEG is to immediately contact the NRC, Region I Reactor Projects Branch #3 Chief or the Division of Reactor Projects, Deputy Director.

With the 24 SPT removed from service, the following actions have been taken to reduce the risk to the off-site and on-site safety related power distribution system:

- Monitoring of critical parameters (oil levels, temperatures and Serveron status (Serveron status is for the 23 SPT only) of the 23 and 4 SPTs on a once per shift basis.
- Elevated the PRA risk level to Yellow for Salem Unit 2 and protection of the redundant off-site power pathway, all three emergency diesel generators and their fuel oil transfer pumps, the station blackout air compressor, switchyard recovery diesel generator, the battery charger Baldor diesel generator, the gas turbine generator, the turbine driven auxiliary feed pump, the relay rooms, the 84 and 64 foot elevation switchgear rooms (including Unit 2 125 V DC Batteries and Battery Chargers) and steam generator atmospheric relief valves. Protected equipment areas are validated and toured by duty operators once per shift.
- Completed a review of the On-line Work Management schedule for the period of 2/14/14 through 2/21/2014. Work activities associated with equipment protected as identified in the NOED for 24 SPT replacement were rescheduled to a date beyond 2/21/2014 or will meet the requirements of performing work in accordance with the station protected equipment program.

During the replacement of the 24 SPT, the following additional actions will be taken to reduce the risk to the off-site and on-site safety related power distribution system:

- Simulator runs will be performed assuming a loss of 23 SPT, lessons learned will be captured and communicated to the operating crews via the just in time training process.
- All operating crews will be briefed on the current plant conditions and the provisions of this proposed enforcement discretion.
- All operating crews will perform table-top reviews of normal, abnormal and emergency operating procedures applicable to the response to a further loss of off-site and on-site electrical distribution and generating equipment.
- Completed a review of the On-line Work Management schedule for the period of 2/14/14 through 2/21/2014. Work activities associated with equipment protected as identified in the NOED for 24 SPT replacement were rescheduled to a date beyond 2/21/2014 or will meet the requirements of performing work in accordance with the station protected equipment program.
- Activities in the Salem switchyard, not directly related to the replacement of 24 SPT, will be prohibited to minimize the possibility of an induced loss of off-site power capability.
- On a once per shift basis, the Salem Shift Manager will receive an update from the Electric System Operator (ESO) on system status, emergent issues and weather forecasts that could impact off-site power availability or grid stability.

- Salem has changed the 23 SPT Serveron TM8 Combustible Gas Monitor sampling frequency to sample every 4 hours (from every 8 hours) for the duration of the request. The Serveron TM8 monitor is required to detect eight recommended IEEE gases in the transformer oil. The Serveron Gas Monitor off normal conditions provide an alarm in the Salem Main Control Room.

k) The status and potential challenges to offsite and onsite power sources, including any current or planned maintenance in the distribution system and any current or planned maintenance to the emergency diesel generators.

During the period of the proposed enforcement discretion, one of two redundant off-site power sources to Unit 2 will be unavailable. The availability of the redundant off-site power source, coupled with the three operable EDGs, continues to provide adequate assurance of the capability to provide power to the ESF systems. Scheduled work activities on the onsite distribution system and emergency diesel generators consist of routine preventive maintenance and surveillance testing during which the systems and components will remain operable.

Completed a review of the On-line Work Management schedule for the period of 2/14/14 through 2/21/2014. Work activities associated with equipment protected as identified in the NOED for 24 SPT replacement were rescheduled to a date beyond 2/21/2014 or will meet the requirements of performing work in accordance with the station protected equipment program.

The offsite distribution systems scheduled work activities consist of the 5039 New Freedom-Orchard outage on 2/15/14 from 0800-1900. The 5039 line will remain in service for the scheduled synchrophasor maintenance. Additionally, relay work activities planned for 5021 Regular Carrier and Remote Trip readings are scheduled on 2/25/14. The 5021 line will also remain in service for the duration of this preventative maintenance window. The Artificial Island Operating Guide was evaluated for a contingent line outage on either the 5039 line or the 5021 line and the resultant effect on Salem Unit 2 is minimal. In the event of a 5039 or 5021 line outage Salem Unit 2 will experience no change to the maximum megawatts and a minimal change in the minimum megavars.

Reliability of Offsite Power Equipment

The Salem Switchyard is fed with three 500 kV lines from three separate 500 kV switchyards (Orchard, New Freedom and Hope Creek). The switchyard is configured in a breaker and one-half arrangement such that each line is connected to the two main busses and is separable from the main busses without affecting the other lines connected to the bus. Thermography is performed quarterly on the switchyard and no degraded conditions exist. There are no conditions affecting the reliability of the breakers and disconnect switches of the 500 kV bus system.

The 500 kV bus system two main busses feed four 500 kV to 13 kV transformers which feed the 13 kV system. Each of these transformers is routinely electrically tested and has the dissolved gas in oil and oil quality sampled. Thermography of the transformers is performed quarterly. There are no anomalies or degraded conditions in the electrical testing, thermography, or oil samples for these transformers.

The 13 kV system feeds 4 vital bus 13kV to 4kV transformers (13, 14, 23, and 24 Station Power Transformers). These transformers feed the 4 kV vital busses for Salem Station Units 1 and 2 (13 and 14 for Unit 1, 23 and 24 for Unit 2). The transformers are fed through circuit breakers, overhead bus work and disconnect switches. The circuit breakers are electrically tested and the bus work has thermography performed quarterly. There are no anomalies or degraded conditions with the 13 kV circuit breakers or bus work/switches.

Each of the13 kV to 4 kV transformers is routinely electrically tested and has the dissolved gas in oil and oil quality sampled. Thermography of the transformers is performed quarterly. With the exception of 24 Station Power Transformer which is being replaced, there are no anomalies or degraded conditions in the electrical testing, thermography, or oil samples for these transformers.

23 SPT feeds Unit 2 4kV Vital Busses A, B and C, and Circulating Water Bus Section 23. The cables from 23 SPT to the vital busses are underground from the transformer to entry into the Turbine Building. The cables from 23 SPT to Circulating Water Bus Section 23 are underground.

The cables have not yet been tested as part of the cable program. Identical cables installed in the same time frame and subject to the same environmental conditions (periodic submergence and wet conditions) have been tested and found to be satisfactory. The tested cables were associated with Station Power Transformers 14 (tested November 2011), 24 (tested November 2012), and 13 (tested May 2013). The cables were tested using Very Low Frequency (VLF) high voltage Tan-Delta testing.

Based on the age of the cable, the greater than required insulation rating, the type of insulation (pink EPR has a high degree of resistance to water treeing), and test history of similar cables, the cables from 23 Station Power Transformer are considered reliable.

Based on the testing, maintenance and the current physical condition of the 500 kV system, the 13 kV system and the 4 kV feeds to the 4kV vital busses, the offsite power supply with 24 Station Power Transformer out of service is reliable.

<u>Reliability of Replacement 24 Station Power Transformer</u>

The replacement 24 Station Power Transformer is the same make and model as the other 13 kV to 4 kV vital bus station power transformers. The replacement transformer was provided new with the installed vital bus station power transformers.

The transformer is maintained as follows:

- Visual inspection for condition and proper oil levels and gas pressures, verification of cooling system operation – 6 months
- Clean and inspect coolers, control panels and transformer exterior, check relays and device function annually
- Oil sample and dissolved gas analysis annually
- Electrical Testing every 6 years (last performed 2011)

There are no anomalies or degraded conditions in the electrical testing, oil samples, or cooling system operation for this transformer. Minor replacement parts (gauges,

regulator, and interrupter board) required to place the transformer in service have been identified and will be installed as the transformer is placed in service.

Based on the history of the replacement transformer and the maintenance and testing performed, the replacement transformer is expected to perform reliably when installed.

Transformer Replacement Work Contingency Actions

If Salem were to experience inclement weather during the installation of the new transformer, scaffolding and tenting are available and can be erected for personnel and equipment protection. Ample rigging supplies will be available as provided by the contract rigging company which will perform all heavy rigging and lifting activities. In case of crane failure, a spare lifting crane is available on site. In addition a crane can be delivered from the PSEG system within 12 hours time. If the transformer monitoring accessories cannot be successfully fitted or installed, PSEG has the ability to perform manual sampling and monitoring of the transformer.

If at any time the 24 SPT replacement activity schedule contingency (1.5 days) reaches no contingency (zero) PSEG will take action IAW TS 3.8.1.1 action a.3 and, PSEG is to immediately contact the NRC, Region I Reactor Projects Branch #3 Chief or the Division of Reactor Projects, Deputy Director to discuss the impact.

Unit 2 Emergency Diesel Generators Reliability

An assessment of Unit 2 EDG reliability indicates for the time period of 1/1/2011 until 2/15/2014 there have been a total of 143 successful demanded starts. There have been no failures to start, run or load during this period. PSEG Business plan metric O.6 "Safety System Performance-PWR" shows that site EDG unavailability currently stands at a value of .0021 vs. a goal of .0106. Salem design supports a single EDG failure and any two diesel generators (and associated vital buses) can supply sufficient power for operation of the required safeguard equipment for a design basis LOCA coincident with a loss of off-site power. Any single EDG can supply power to its respective 4kV bus during a total loss of AC power event.

Salem Unit 3 Gas Turbine Generator Reliability

Prior to the start of the enforcement discretion period, Salem Unit 3 will be run to verify availability of the jet. Salem will also perform a verification of above ground fuel oil line heat tracing. Heat trace function verification is performed by checking the heat trace illuminated indicator light once per shift.

Every 12 hours start, load and run the Gas Turbine Generator (GTG) Alpha Engine. The length of the loaded run needs to be of sufficient duration to reach equilibrium of GTG engine operating parameters. If the GTG Alpha Engine is unavailable PSEG will take action IAW TS 3.8.1.1 action a.3 and PSEG is to immediately contact the NRC, Region I Reactor Projects Branch #3 Chief or the Division of Reactor Projects, Deputy Director.

Salem Units 1 and 2 share a common Gas Turbine Generator (Salem Unit 3 Jet). The Salem Unit 3 Jet normal standby alignment is dedicated to Salem as an alternative power source. The Salem Unit 3 Jet has two engines each of which can run individually and are capable of independent operation. Only one engine is required to satisfy the mission of supplying 4 KV loads in the event of a loss of all AC power. Salem Unit 3 is tested monthly. Salem Unit 3 has black start capability which is tested annually. The last black start test was successfully completed June 2013. Only Salem Unit 3 Jet engine Alpha is available during this period of enforcement discretion.

Salem PRA indicates that 4 hours are available to restore power to the battery chargers before the station batteries are depleted requiring the use of Salem Unit 3. Offsite power recovery is required by 3.67 hours so that once Offsite power has been restored, on-site recovery actions can be taken to align the battery chargers and then perform the actions needed to prevent core damage.

The Jet was able to be successfully run on at least one of the two engines over 90% of the attempted runs in the past year. Although Salem Unit 3 has only been successfully remotely started with one jet 77% of the time, simple actions such as resetting the bridge controller allows the Jet to be successfully run. These actions can be performed well within the required times listed above. A review of the maintenance rule functional failure determinations indicate three maintenance rule functional failures during approximately 36 attempted runs. These failures included a lack of fuel due to clogged fuel filters and another time due to cold fuel. The Jet engine has had new fuel filters installed on February 3rd, 2014 and heat trace and insulation was installed for cold weather operations.

A maintenance rule functional failure includes:

Any failure causing loss of AC power from Unit 3 twin turbine-generator. Functional failures include, but are not limited to:
1) Unavailability or loss of both jet engines;
2) Fault in the twin-turbine generator or its controls resulting in emergency shutdown of the jet engines.

Salem Unit 3 is capable of providing power to the grid during high demand periods. During this period of enforcement discretion a decision has been made by Salem management to not use Salem Unit 3 as a peaking Unit. Salem will inform the ESO that Salem Unit 3 is unavailable during this extended period of enforcement discretion.

Salem Unit 3 is capable of providing alternate power to meet Hope Creek Technical Specifications. Alignment to Hope Creek allows the AOT for EDG "A" or "B" to extend from 72 hours to 14 days. Salem Unit 3 provides additional defense-in depth during the extended Hope Creek AOT.

Salem Unit 3 is not considered available for Hope Creek during this extended request for enforcement discretion for the 24 SPT replacement and return to service. The unavailability of Salem Unit 3 has been communicated and agreed upon by the Salem and Hope Creek Plant Managers. The Hope Creek Shift Manager issued a standing order stating Salem Unit 3 is not available to Hope Creek during the period of this enforcement discretion.

I) The safety basis for the request and an evaluation of the safety significance and potential consequences of the proposed course of action.

The PRA assessment values presented in the following discussion were performed considering an additional 7 days added to the 72-hour AOT. This is one day greater than enforcement discretion period being requested.

a) Use the zero maintenance PRA model to establish the plant's baseline risk and the estimated risk increase associated with the period of enforcement discretion.

The baseline CDF using the zero test and maintenance PRA model is 2.02E-05 per year. The incremental conditional core damage probability (ICCDP) associated with the additional 7 days is 4.56E-08 or ~5E-08 and is below the 5E-07 threshold established by NRC Inspection Manual Chapter 0410, "Notices of Enforcement Discretion". There is no net increase in risk of core damage because this risk increase is within the Salem's normal work control levels.

The baseline LERF using the zero test and maintenance PRA model is 1.12E-06 per year. The incremental conditional core damage probability (ICCDP) associated with the additional 7 days is 2.40E-09 or ~2E-09 and is below the 5E-08 threshold established by NRC Inspection Manual Chapter 0410, "Notices of Enforcement Discretion". There is no net increase in risk of large early release because this risk increase is within the Salem's normal work control levels.

There is no net increase in radiological risk to the public because the calculated risk increases are within the site's normal work control levels.

b) Discuss the dominant risk contributors (cut sets/ sequences) and summarize the risk insights for the plant-specific configuration the plant intends to operate in during the period of enforcement discretion.

<u>For CDF</u>
A comparison of cutsets for the plant-specific configuration to the zero test and maintenance base case shows little change for the topmost dominant cutsets. The first new cutset appears at 8.7E-09 per year and is a plant trip followed by failure of the 23 SPT, 2B EDG, 2C EDG, RCP seals and Auxiliary Building ventilation.

The initiating events of the new cutsets that appear due to this configuration, are switchyard related loss of offsite power (%TES) at 42% , plant trip (%TT) at 35% and plant trip with loss of power conversion system (%TP) at 21%.

- Baseline CDF contributions are %TES at 5.6%, %TT at 10% and %TP at 8.9%.
- CDF contributions in the configured case are %TES at 15.2%, %TT at 9.3% and %TP at 8.2%.

The new accident sequences involve plant transients followed by failures of the 23 SPT, 2B EDG and 2C EDG. This challenges reactor coolant pump (RCP) seals which subsequently fail.

<u>For LERF</u>

A comparison of cutsets for the plant-specific configuration to the zero test and maintenance base case shows little change for the topmost dominant cutsets. The first new cutset, at 2.1E-10 per year is a plant trip followed by failure of the 23 SPT, 2B EDG, 2C EDG, RCP seals and Auxiliary Building ventilation. This cutset also includes a pressure induced steam generator tube rupture (PI-SGTR).

The initiating events of the new cutsets that appear due to this configuration, are %TES at 91% , %TT at 6% and %TP at3% .

- Baseline LERF contributions are %TES at 4.7% , %TT at 3% and %TP at 4.6%.
- LERF contribution in the configured case are %TES at 14.2%, %TT at 3% and %TP at 4% .

The new accident sequences are similar to the new CDF sequences but include PI-SGTRs. Those sequences that initiate with a switchyard related loss of offsite power include auxiliary feedwater failures; specifically, failure to refill the AFWST or to align the alternate AFW suction source.

c) Explain compensatory measures that will be taken to reduce the risk associated with the specified configuration. Compensatory measures to reduce plant vulnerabilities should focus on both event mitigation and initiating event likelihood.

Salem Unit 2 personnel will be alerted to an elevated risk condition by raising the on-line risk condition to YELLOW. PSEG uses a three tier scale – GREEN, YELLOW, RED. The risk condition is broadly publicized throughout the station through morning reports, staff meetings and Outage Control Center shift briefs.

No other safety related equipment is scheduled to be removed from service for the duration of this maintenance activity.

Equipment required to prevent a loss of offsite power or to mitigate a loss of offsite power will be protected to reduce the likelihood of human error impacts and to eliminate test and maintenance unavailability on this equipment. The protected equipment is:

1) Station blackout (SBO) Air Compressor
2) The 2A, 2B and 2C emergency diesel generators (EDG)
3) Both 21 and 22 diesel fuel oil transfer pumps (DFOTP)
4) All four steam generator atmospheric power operated relief valves (MS10s)
5) Salem Switchyard components:
   i) 4 SPT
   ii) Disconnects 4T50 & 4T60
   iii) C-D breaker
   iv) D-E breaker
   v) 23 SPT
6) 4kV Vital Bus in-feeds
   i) 23ASD
   ii) 23BSD
   iii) 23CSD
7) Circ Water in-feed & cross-connect
   i) 23CW1AD

ii) 2CW2BD
8) 23 Turbine Driven AFW Pump
9) Unit 2 AFW Room Cooler
10) Gas Turbine Generator (a/k/a Jet or Unit 3)
11) Battery Charger EDG (a/k/a Baldor)
12) Open racks containing 500kV, 13kV, and 4kV relays in the Unit 2 Relay Room

Work in the Salem switchyard will be carefully coordinated to minimize the potential for 24 SPT replacement activities impacting the remaining source of offsite power.

Compensatory measures to manage the risk of internal fire are addressed below in question f).

d) Discuss how the proposed compensatory measures are accounted for in the PRA.

Risk management actions are not accounted for in the PRA results.

e) Discuss the extent of condition of the failed or unavailable component(s) to other trains/divisions of equipment and what adjustments, if any, to the related PRA common cause factors have been made to account for potential increases in their failure probabilities.

The 24 SPT is the only Salem Station Power transformer exhibiting high levels of combustible gases in the transformer oil. The dissolved gas in oil and oil physical properties for 3 Station Power Transformer, 4 Station Power Transformer and 23 Station Power Transformer are all normal. Electrical testing of 3 Station Power Transformer, 4 Station Power Transformer and 23 Station Power Transformer showed no anomalies. The 24 SPT did not fail because it was proactively taken out of service to preempt sudden or unexpected failure. Therefore, common cause probabilities were not adjusted.

f) Discuss external event risks for the specified plan configuration.

Salem does not have a Fire PRA approved for numerical quantification. Revision 0 of the Fire PRA was completed in 2009 and is currently being updated. The Fire PRA model has also not been Peer Reviewed and it is for these reasons the model cannot be used for a quantitative analysis. However, information from the Salem Fire PRA can be used to provide insights into fire risk associated with this configuration and help define compensatory measures that can be put in place.

Using the insights from the fire model for the Unit 2 equipment configuration described above the following insight can be made. The fire areas that would result in a complete LOSP for Unit 2 if a fire were to occur in that area would be the fire areas of concern. The fire compensatory measures are aligned with the goal of minimizing the probability of a fire causing damage in the risk significant fire areas. These compensatory measures will include a dedicated roving fire watch to ensure prompt identification of fires and the initiation of fire mitigation in these areas.

Salem does not currently have a seismic or flood PRA model. However, seismic and flood events were considered and it was determined that there is no net increase in risk for the NOED configuration. The offsite power cables for the 23 and 24 SPTs are routed in the same fire areas and in the same type of route points. A review of the IPEEE indicates that a seismic or flood event that could occur during this configuration would result in the same failure state because offsite power is very likely to be lost. A seismic or flood event would result in the same risk given the configuration of the NOED condition or normal operation.

g) Discuss forecasted weather conditions for the NOED period and any plant vulnerabilities related to weather conditions.

Forecasted weather conditions for the extended AOT are typical winter conditions. A winter storm is currently receding. Weather over the next ten days is expected to become less severe than recent conditions. Severe weather over the past few weeks has not impacted offsite power. The National Weather Service was used to determine forecasted weather conditions.

m) Demonstration that the NOED condition, along with any compensatory measures, will not result in more than a minimal increase in radiological risk, either in a quantitative assessment that risk will be within the normal work control levels (ICCDP less than or equal to 5E-8) or in a defensible qualitative manner.

As demonstrated in section I above, the requested enforcement discretion will not result in more than a minimal increase in risk. There are no unforeseen challenges to the off-site and on-site power sources. Measures will be implemented to prevent any maintenance activities on systems in the plant that could impact the AC power system. Compensatory measures will be implemented to prevent any work activities in the plant that could challenge the availability and reliability of redundant systems. There is no significant difference in nuclear safety risk by extending the Allowed Outage Time to accomplish required repairs and testing.

Based on the above, the extended Allowed Outage Time will not create undue risk to public health and safety.

n) The forecasted weather and pandemic conditions for the NOED period and any plant vulnerabilities related to weather or pandemic conditions.

No severe weather conditions are forecasted for the duration of the requested AOT extension of the NOED period. The 9-day forecast consists of some periods of precipitation with high/low temperatures ranging from 52 degrees to 11 degrees F.

During the NOED period, Salem Units 1 and 2 may be vulnerable to Delaware River grassing challenging the cooling water intake. Current forecast of river grassing levels show grassing volumes well below Salem procedural action levels. River grassing levels are monitored daily.

No known pandemic conditions exist or are predicted to occur during the NOED period.

o) The basis for the conclusion that the noncompliance will not create undue risk to the public health and safety.

PSEG Nuclear has evaluated the proposed request and determined that it involves no significant hazards considerations. According to 10 CFR 50.92, "Issuance of amendment," paragraph (c), a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not:

(A) Involve a significant increase in the probability or consequences of an accident previously evaluated; or

(B) Create the possibility of a new or different kind of accident from any accident previously evaluated; or

(C) Involve a significant reduction in a margin of safety.

In support of this determination, an evaluation of each of the three criteria set forth in 10 CFR 50.92 is provided below regarding the proposed action.

A. The request for enforcement discretion does not involve a significant increase in the probability of occurrence or consequences of any accident previously evaluated.

The probability of occurrence of an accident will not be significantly affected by granting this enforcement discretion. The requested extension of the Allowed Outage Time (AOT) does not affect the way in which the unit is operated, and thus does not affect the frequency of any initiators for accidents evaluated in the Updated Final Safety Analysis Report (UFSAR). The UFSAR evaluates several accidents (e.g., loss of coolant accident) coincident with a loss of off-site power. During the time of the enforcement discretion, with the capability of the on-site and off-site power circuits degraded, if the unit experiences a reactor scram as a result of any of the accidents evaluated in the UFSAR, a loss of off-site power is likely to occur. However, the probability of the initiating events themselves (e.g., LOCA) is unaffected.

The consequences of an accident, in terms of off-site dose, will not be significantly changed provided the mitigating actions credited in the accident analyses are accomplished in accordance with the analysis assumptions. The accidents evaluated in the UFSAR assume that electrical power is available to power safety-related equipment. These evaluated accidents assume a loss of off-site power and a concurrent single failure of equipment needed to mitigate the accident. The requested AOT extension does not change these assumptions, as the emergency diesel generators are available as assumed in the accident analyses.

Therefore, the requested enforcement discretion does not significantly increase the probability or consequences of an accident previously evaluated.

B. The request for enforcement discretion does not create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed action does not involve physical alteration of the unit. No new equipment is being introduced and installed equipment is not being operated in a new or different manner. There is no change being made to the parameters within which the unit is operated. There are no setpoints at which protective or mitigative actions are initiated that are affected by this proposed action. This proposed action will not alter the manner in which equipment operation is initiated nor will the function demands on credited equipment be changed. No alteration in the procedures which ensure the unit remains within analyzed limits is proposed, and no change is being made to procedures relied upon to respond to an off-normal event. As such, no new failure modes are being introduced. The proposed action does not alter assumptions made in the safety analysis. Therefore, the proposed action does not create the possibility of a new or different kind of accident from any accident previously evaluated.

C. The proposed request for enforcement discretion does not involve a significant reduction in a margin of safety.

Since there are no changes to the plant design and safety analysis, and no changes to the AC electrical power distribution system design, including any instrument setpoints, no margin of safety assumed in the safety analysis is affected. Should off-site power be lost during a transient or accident condition, the on-site power sources are capable of mitigating the accident or transient conditions. Therefore, the proposed enforcement discretion will not involve a significant reduction in a margin of safety.

Therefore, the proposed action does not involve a significant hazards consideration under the criteria set forth in 10 CFR 50.92(c).

p) The basis for the conclusion that the noncompliance will not involve adverse consequences to the environment.

There is no significant change in the types or a significant increase in the amounts of any effluent that may be released off-site since the proposed actions do not affect the generation of any radioactive effluent nor do they affect any of the permitted release paths: and

There is no significant increase in individual or cumulative occupational radiation exposure. The proposed action in this request for Enforcement Discretion will not significantly affect plant radiation levels, and therefore do not significantly affect dose rates and occupational exposure.

q) Statement of NOED request review and approval by the PORC.

The request for enforcement discretion was approved by the Salem Plant Operations Review Committee (PORC) on February 14, at 1430 hours.

r) Statement that the written NOED request will be submitted to NRC within two working days and a follow-up license amendment request will be submitted following NRCs verbal granting of the NOED.

This submittal is the written NOED request following the verbal approval granted on February 15, 2014 at 2115.

This request for enforcement discretion is a one-time only extension of the Allowed Outage Time to complete restoration activities on the 24 SPT. As such, a follow-up license amendment is not required. This was agreed to during the February 15, 2014 teleconference.

s) Other supporting information.

Electrical Distribution System Description

Both Salem units receive offsite power at 500 kVAC from three transmission lines. The 500kVAC energizes a ring bus that supplies power to the stations through four SPTs that step down 500kVAC to 13kVAC.

- The 1 and 2 SPTs supply 13kVAC to the 11, 12, 21, and 22 SPTs. These transformers step down 13kVAC to 4kVAC for the station group buses (balance of plant). These transformers are not at issue.
- The 3 and 4 SPTs supply 13kVAC to the 13, 14, 23 and 24 SPT. Specifically:
  - 3 SPT powers the 13 and 24 SPT;
  - 4 SPT powers the 14 and 23 SPT.
  - 13 and 14 SPT supply 4kVAC power to the three Unit 1 vital buses and circulator bus;
  - 23 and 24 SPT supply 4kVAC power to the three Unit 2 vital buses and circulator bus.
  - Normally the three vital buses are aligned such that all three buses are not powered from the same 13/4kVAC transformer.
  - With 24 SPT inoperable, all three Unit 2 vital buses and the circulator bus are aligned to the 23 SPT.