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January 21, 2013

Serial: BSEP 13-0010

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

Subject: Brunswick Steam Electric Plant, Unit Nos. 1 and 2
Docket Nos. 50-325, 50-324
Response to NRC Request for Additional Information Regarding Diesel Generator (DG) Completion Time (CT) Extension for Technical Specification (TS) 3.8.1, "AC Sources - Operating" (TAC NO. ME8893 and ME8894)

Reference:

1. Letter from M. Annacone (CP&L) to the U.S. Nuclear Regulatory Commission, Request for License Amendments - Diesel Generator (DG) Completion Time (CT) Extension for Technical Specification (TS) 3.8.1, "AC Sources - Operating," dated June 19, 2012, ADAMS Accession Number ML12173A112

2. Letter from F. Saba (NRC) to M. Annacone (CP&L) Request for Additional Information Concerning the Risk Evaluation for the Emergency Diesel Generator Completion Time Extension for Technical Specification 3.8.1, "AC Sources - Operating," dated November 21, 2012, ADAMS Accession Number ML12310A305

On June 19, 2012 (i.e., Reference 1), Carolina Power & Light (CP&L) Company requested a revision to the Technical Specifications (TS) for the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2. The proposed revision extends the Completion Time (CT) of TS 3.8.1, Required Action D.4 for an inoperable diesel generator (DG) from 7 days to 14 days. A commensurate change is also proposed to extend the maximum Completion Time of TS 3.8.1, Required Actions C.3 and D.4. BSEP also proposed the addition of a supplemental AC power source (i.e., a supplemental diesel generator). On November 21, 2012 (i.e., Reference 2), the NRC provided a request for additional information (RAI) regarding the proposed amendment request. The response to this RAI is included in the enclosure to this letter.

This letter contains no regulatory commitments.

Please refer any questions regarding this submittal to Mr. Lee Grzeck, Manager – Regulatory Affairs, at (910) 457-2487.

A001
NRR

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on January 21st, 2013.

Sincerely,

Michael J. Annacone

MAT/mat

Enclosure:

Response to Request for Additional Information cc (with enclosure):

U. S. Nuclear Regulatory Commission, Region II
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U. S. Nuclear Regulatory Commission
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Mr. W. Lee Cox, III, Section Chief
Radiation Protection Section
North Carolina Department of Environment and Natural Resources
1645 Mail Service Center
Raleigh, NC 27699-1645

Response to Request for Additional Information

Background

On June 19, 2012, Carolina Power & Light (CP&L) Company requested a revision to the Technical Specifications (TS) for the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2. The proposed revision extends the Completion Time (CT) of TS 3.8.1, Required Action D.4 for an inoperable diesel generator (DG) from 7 days to 14 days. A commensurate change is also proposed to extend the maximum Completion Time of TS 3.8.1, Required Actions C.3 and D.4. BSEP also proposed the addition of a supplemental AC power source (i.e., a supplemental diesel generator). On November 21, 2012, the NRC provided a request for additional information (RAI) regarding the proposed amendment request. The responses to this RAI follow. Procedures and calculations referenced in the response will be provided upon request.

NRC Question 1

Provide a legible copy of the Brunswick Key One Line Diagram showing 230 kV, 24 kV and 4160V Systems (Copy of the diagram currently available with the NRC staff is not legible).

Response to Question 1

The following plant drawing is provided in Attachment 1:

- F-03043, 230KV, 24KV & 4160 Volt Systems Key One Line Diagram

NRC Question 2

The licensee stated in the LAR, Enclosure 1, page 12, that two 200 kilo Watts (kW), 480 volts (V) alternating currents 60 hertz diesel generators, referenced as severe accident management alternative (SAMA) diesel generators, are available to supply the blackout unit battery chargers if AC power cannot be restored to any emergency bus of the blackout unit (i.e., if the crosstie is not possible)..

Provide one-line drawing(s) showing the SAMA diesel generators' connection to the electrical distribution buses.

Response to Question 2

The following plant drawings are provided in Attachment 1:

- F-30053, 480 Volt System MCC 1CA, 1CB, 1PA, & 1SA Auxiliary One Line Diagram
- F-03053, 480 Volt System MCC 2CA, 2CB, 2PA, & 2SA Auxiliary One Line Diagram

F-30053 and F-03053 show the SAMA diesel generators' connection to the electrical distribution buses:

- 2-SAMA-DIESEL-1 can be aligned to MCC 1CB or MCC 2CA.

- 2-SAMA-DIESEL-2 can be aligned to MCC 1CA or MCC 2CB.

As shown on F-30053, and as directed in plant abnormal operating procedure 0AOP-36.2, Station Blackout, for a Unit 1 blackout 2-SAMA-DIESEL-2 is aligned to motor control center (MCC) 1CA to supply Battery Chargers 1A-1/1A-2, and 2-SAMA-DIESEL-1 is aligned to MCC 1CB to supply Battery Chargers 1B-1/1B-2.

As shown on F-03053, and as directed in plant abnormal operating procedure 0AOP-36.2, Station Blackout, for a Unit 2 blackout 2-SAMA-DIESEL-1 is aligned to MCC 2CA to supply Battery Chargers 2A-1/2A-2, and 2-SAMA-DIESEL-2 is aligned to MCC 2CB to supply Battery Chargers 2B-1/2B-2.

As shown on F-30053 and F-03053, and as directed in plant abnormal operating procedure 0AOP-36.2, Station Blackout, for a dual unit blackout 2-SAMA-DIESEL-1 is aligned to MCC 1CB to supply Battery Chargers 1B-1/1B-2, and 2-SAMA-DIESEL-2 is aligned to MCC 2CB to supply Battery Chargers 2B-1/2B-2.

NRC Question 3

The licensee stated in the LAR, Enclosure 1, page 14, that the supplemental diesel generator (SUPP-DG) electrical system will be provided with metering and protective relaying at the SUPP-DG output breaker and the new BOP [Balance-of-Plant] Bus switchgears.

Describe and provide a copy of the metering and protective relaying design for the SUPP-DG and the new BOP Bus switchgears. Also, describe measures, which will be taken to maintain electrical separation between the two trains of BOP buses to which the SUPP-DG can be connected.

Response to Question 3

The following plant drawings are provided in Attachment 1:

- 7002546D11501, One Line Diagram (Sheet 1)
- SK-79694-Z-7422, 4160 Volt Switchgear 1C Compartment "1-A3B" SUPP Diesel Gen Incoming Line Control Wiring Diagram
- LL-91003 (Sheet 45)

The SUPP-DG metering and protective relaying includes SEL-700G (i.e., digital multifunction generator protective relay) for the SUPP-DG output breaker and SEL-587 (i.e., digital multifunction protective relay) for the SUPP-DG aux services breaker. The metering and protection details are shown on Drawing 7002546D11501, One Line Diagram (Sheet 1).

The new BOP switchgear includes a 50/51 relay. Sketch SK-79694-Z-7422, 4160 Volt Switchgear 1C Compartment "1-A3B" SUPP Diesel Gen Incoming Line Control Wiring Diagram, shows the protective relaying inside the compartment for the BOP bus 1C breaker and is representative of the breaker installations at the BOP Buses 1D, 2C, and 2D.

Referenced Drawing LL-91003 (Sheet 45), 4160 Volt Switchgear 1C Compartment "1-AB9" Unit Trip/Load Shed Circuitry Control Wiring Diagram, shows the 94-UT1 relay off the plant Unit

Auxiliary Transformer (UAT) 86 relay to avoid the diesel staying connected to the BOP bus should a UAT trip occur (e.g., loss of offsite circuit) during testing (i.e., SUPP-DG paralleled to the selected BOP bus). The "TEST" contact is from the SUPP-DG Programmable Logic Controller (PLC) to be used during "synchronized to BOP" operations. The new BOP bus breakers are normally open which provides redundant means of separation between the BOP buses. The logic of the new BOP bus breakers is controlled by the SUPP-DG PLC logic which allows only one of the four breakers to be selected and closed at any time. The BOP bus breaker to be used is selected and closed from the SUPP-DG engine control panel.

NRC Question 4

The licensee stated in the LAR, Enclosure 1, page 13, that the SUPP-DG will be of commercial-grade type, non Class 1E, permanently-installed inside the plant protected area, and outside the existing power block building; east of the switchyard and north of the transformer yard.

Provide a plant physical drawing showing the proposed physical location of major components of the SUPP-DG, such as the diesel enclosure, electrical enclosure, mechanical enclosure, radiator, fuel storage tank, and refill station for the tank.

Response to Question 4

The following plant drawings are provided in Attachment 1:

- NRC RAI 4 (Sheet 1), SUPP-DG Location, Site Plot Plan
- NRC RAI 4 (Sheet 2), SUPP-DG General Arrangement

Drawing NRC RAI 4 (Sheet 1) shows the physical location of the SUPP-DG (i.e., major components) on the BSEP site plot plan. Drawing NRC RAI 4 (Sheet 2) shows the general arrangement of the SUPP-DG (i.e., major components) at this location.

NRC Question 5

The licensee stated in the LAR, Enclosure 1, page 15, that the electrical enclosure will house the SUPP-DG output breaker switchgear, engine/generator control panel, 125 V direct current (DC) battery system with battery charger, 4160:480V auxiliary power transformer, 480V automatic transfer switch, and 480V motor control center.

Provide one line diagram of the above alternate current (AC) and DC electrical equipment to be located in the Electrical Enclosure.

Response to Question 5

The following plant drawings are provided in Attachment 1:

- 7002546D11501, One Line Diagram (Sheet 1)
- 7002546D11501, One Line Diagram (Sheet 2)
- 7002546D11503, MCC Schematic (Sheets 1 through 5)
- 7002646D11504, Enclosure Schematic (Sheet 1)
- 7002546D02503, DC Power Schematic (Sheet 1)

Drawing 7002546D11501, One Line Diagram (Sheet 1) shows the SUPP-DG output breaker to the plant 4160V load bus and the auxiliary service breaker to the 4160:480V auxiliary power transformer, which is the SUPP-DG supply to 480V automatic transfer switch (ATS).

Drawing 7002546D11501, One Line Diagram (Sheet 2) shows the 480V ATS and 480V MCC. Drawing 7002546D11503, MCC Schematic (Sheets 1 through 5) show the 480V MCC schematics.

Drawing 7002646D11504, Enclosure Schematic (Sheet 1) shows the 120VAC system in the electrical enclosure.

Drawing 7002546D02503, DC Power Schematic (Sheet 1) shows the 125VDC power schematic including the battery system, battery charger, and the DC distribution panel which includes a DC supply breaker to the Engine Control Panel.

NRC Question 6

The licensee stated in the LAR, Enclosure 1, page 15, that the fuel storage tank can be replenished via a refill station for the tank.

Provide details of refill station such as the source of fuel for the refill station, and the source of any power supply needed at the refill station including a brief description of procedures used to replenish the tank.

Response to Question 6

<u>Refill Station</u>

A refill station is located at grade elevation adjacent to the elevated platform upon which the 10,000 gallon fuel oil storage tank is mounted. The fuel oil storage tank is refueled from grade elevation via fuel tanker truck.

<u>Source of Fuel for the Refill Station</u>

The Grade Ultra-Low Sulfur No. 2-D (2-D S15) diesel fuel source is the Selma Tank Farm, the same supply source used for the safety-related emergency diesel generators (EDGs). The Selma Tank Farm is located in Selma, NC, approximately 145 miles driving distance north of

BSEP and approximately 80 miles line distance inland from the NC coast. The fuel is delivered by fuel tanker truck.

The SUPP-DG fuel tank may also be filled via a normally-closed fill connection on top of the tank.

Source of Power Supply for Refill Station

The electrical power for the fuel transfer system is provided from the SUPP-DG motor control center. The SUPP-DG when running supplies the motor control center from its generator output through a 4160V to 480V transformer and automatic transfer switch. The automatic transfer switch aligns the SUPP-DG as the preferred source when it is running. The automatic transfer switch can be manually aligned to the SUPP-DG output if the automatic transfer function failed.

When the SUPP-DG is not running (i.e., shutdown) the motor control center is powered by plant power through the automatic transfer switch. The SUPP-DG is 24-hour black-start capable under loss of plant power conditions if the plant power is not available (i.e., loss of offsite power, station blackout).

Description of Procedures to Replenish the Fuel Tank

A new operating procedure developed for the SUPP-DG will include a section for unloading and transferring fuel oil to the SUPP-DG fuel tank by tanker truck. These procedure instructions will effectively mimic the procedure instructions for unloading and transferring fuel oil to the EDG main fuel oil storage tank.

The instructions for unloading and transferring fuel oil to the Emergency Diesel Generator main fuel oil storage tank include:

- Verification of valve and electrical lineups prior to starting, and completion of valve and electrical lineups upon completion of fuel unload.

- Pre-offload sampling is performed for water and sediment. The source tank at the Selma Tank Farm is certified to meet ASTM D-975-06b, Standard Specification for Diesel Fuels, and is documented in a certificate of analysis maintained by our corporate headquarters. The ASTM D-975-06b requirements are prescribed in the corporate specification for diesel fuel oil testing. This specification is used for the laboratory testing of diesel fuel oils suitable for use in safety-related diesel engines utilized at the Progress Energy Nuclear Generating Sites including BSEP. The specification includes Grade Ultra-Low Sulfur No. 2-D (2-D S15) diesel fuel oil.

- Instructions to connect to the refill station, transfer fuel to the tank, and terminate and disconnect from the refill station.

- Tank volume and level control requirements.

- Personnel and environmental safety requirements (i.e., chemistry notification and involvement, oversight of unloading by qualified plant personnel, grounding, and venting of tanker truck)

NRC Question 7

Justify why the regulatory commitments for the following additional compensatory actions as recommended in the NRC Branch Technical Position (BTP) 8-8 have not been provided:

a. The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended CT, and

b. TS required systems, subsystems, trains, components, and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components, and devices.

Response to Question 7a

The requirements in fleet procedures NGGM-IA-0003, Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants and SORMC-COM-090, System Operating Status for Internal Communications, establish communication protocols which meet the additional compensatory action as recommended in the NRC BTP 8-8.

NGGM-IA-0003 implements North American Electric Reliability Corporation (NERC) Reliability Standards. Fleet procedure NGGM-IA-0003, describes the division of responsibility between the Nuclear Generation Group and the Transmission Operations and Planning Department for compliance to NERC Reliability Standards.

The BSEP Control Room is responsible for the direct operation of the plant equipment and systems, control of plant equipment clearances, operational communications with the grid operators in Power System Operations, and maintaining overall command and control of work activities at the plant site. BSEP Operations shall comply with this agreement to support compliance to NERC Standards.

The Power System Operations is responsible for the operation of the transmission grid, operating the transmission system in a manner to meet the Nuclear Plant Interface Requirements (NPIRs), issuing clearances on transmission equipment, controlling work activities on transmission grid equipment, maintaining transmission voltage levels, operational communication with BSEP Control Room Operators, scheduling / dispatching generation and bulk power interchange, communicating Reliability Coordinator directives to Generator Operators, and ensuring that applicable generation facilities are included within the metered boundaries of the transmission system.

In day-to-day operations, Power System Operations shall contact BSEP Operations-Control Room each business day to discuss the status of the plant and the transmission system and review upcoming plans and work activities for the day. Power System Operations personnel will relay any directives issued by the Reliability Coordinator relating to Nuclear Generation Group generating facilities to BSEP Operations-Control Room personnel. Power System Operations shall notify BSEP Operations-Control Room of switching and testing activities which have the potential to create perturbations on the generator or plant switchyard prior to performing these activities.

In the day-to-day operations, BSEP Operations-Control Room shall notify Power System Operations of any existing or anticipated Limiting Conditions for Operation (LCO) or other conditions having the potential to impact the generation capability of the plant. BSEP

Operations-Control Room shall notify Power System Operations of any existing or anticipated plant equipment alignments or out of service equipment conditions which make offsite power of greater importance to the plant from a risk management point of view. The intent of this notification is to make Power System Operations aware of times when the consequences of a loss of offsite power are greater, so that Power System Operations can take measures to minimize to probability of occurrence of a loss of offsite power to the plant. Additionally, the BSEP Outage & Scheduling shall contact Power System Operations each week to discuss the operating conditions scheduled or anticipated for the next seven days to accommodate coordination of activities and generation planning.

SORMC-COM-090 defines the System Operating Status levels, and when to issue them. The System Operator should notify all plants of the current system operating status when it changes to another level. The plants should be notified of anticipated Reliability Alerts as early as practical to allow sufficient time to make staffing adjustments. A System Reliability Alert should be declared when Power System Operations determines that extra precautions should be taken based on projected operating reserves being less than the largest single contingency, or it is anticipated that a single contingency would result in a generation-load imbalance that may require load curtailments or firm load shedding to correct. This imbalance could be due to insufficient system resources, insufficient off system resources or transmission import limitations.

Response to Question 7b

OPS-NGGC-1305, Operability Determinations, provides the guidance to be followed in the determination of operability of structures, systems, or components (SSC) described in TS. The scope of the SSCs considered in the operability determination process includes; (a) SSCs required to be operable by TS. These SSCs may perform required support functions for other SSCs required to be operable by TS, and (b) SSCs that are not explicitly required to be operable by TS, but that perform required support functions as specified by the TS definition of operability for SSCs required to be operable by TS.

Positive measures are provided to preclude subsequent testing or maintenance activities on these TS required systems, subsystems, trains, components, and devices by existing plant procedures.

0AP-025, BNP Integrated Scheduling, provides requirements for protected equipment process, methodology and posting. When an EDG becomes inoperable, 0AP-025 requires the remaining offsite sources and EDGs be protected. The protected equipment process ensures the remaining system/components available to perform that function shall be protected by physical and/or administrative means. These controls apply to maintenance and testing activities that place the equipment outside its normal, as designed, configuration.

OPS-NGGC-1311, Protected Equipment, requires the protected train equipment be administratively controlled to minimize the possibility of loss of use. Removing an EDG from service requires protecting the other three EDGs and associated emergency buses, and the normal power source (i.e., offsite circuits) to all emergency buses. The equipment must be posted prior to rendering the listed component unavailable. The protected train is extended to work within the station switchyard and associated relays, switchgear, and transformers. This includes activities performed by station, supplemental, and transmission personnel. For emergent work affecting EDG availability, posting should be established as required, as soon as possible after the unavailability is identified.

Protected Train Communications include identifying the scheduled protected train on the plant morning report, in the Main Control Room, Work Control Center, and Plant Entry Security Control Point. The scheduled protected train and any posted protected equipment is discussed in the beginning of shift briefings for each group.

NRC Question 8

The licensee stated in the LAR, Enclosure 1, page 14, that the time required to enable the SUPP-DG to supply power to any Electrical-Bus is within one hour from the station blackout (SBO) event.

Confirm that a coping analysis has been performed which shows that the SBO unit can remain in a safe shutdown condition without any AC power for the first hour of the SBO event.

Response to Question 8

BSEP document 8S42-P-101, Station Blackout Coping Analysis Report, BNP Unit 1&2, Revision 13, issued January 4, 2012 provides the station blackout coping analysis, which shows that the SBO unit can remain in a safe shutdown condition without any AC power for the first hour of the SBO event.

NRC Question 9

According to BTP Page 8-8-6, although the extended CT is allowed for pre-planned maintenance activities, it could be used for corrective maintenance on a limited bases. Confirm that the licensee will continue to meet the maintenance rule availability/reliability requirements, the reactor oversight process performance indicator criteria for availability/reliability, and the emergency diesel generator target reliability criterion of 0.975.

Response to Question 9

BSEP will continue to meet the maintenance rule availability/reliability requirements, and the reactor oversight process performance indicator criteria for emergency diesel generator availability/reliability.

Overall EDG availability will be improved as a result of the extended CT. The maintenance strategy for the four Nordberg safety related EDGs will remain unchanged after the addition of the non-safety supplemental diesel generator. The preventative maintenance schedule will follow the same periodicity and scope, the only difference is in the implementation. Having the non-safety related SUPP-DG will allow a longer out of service time for the EDGs allowing more work to be performed during out of service times. Performing EDG work within one 14-day CT versus two 7-day CTs only requires removing the EDG from service and returning it to service one time, rather than twice as required if using two 7-day CTs. This reduces the time that an EDG is unavailable when using the 14-day CT while accomplishing the same amount of work. Bundling of this work will improve overall reliability as well as availability by reducing the number of times the EDGs are subjected to intrusive maintenance activities. The 7-day CT will also allow major maintenance which would exceed the current 7 day LCO to be performed without a plant impact. This additional out of service time will be used to complete several major improvement projects which in the long term will have a positive effect on emergency diesel reliability.

The Station Blackout Reliability target of 0.975 will not be altered. The criteria set forth in Regulatory Guide 1.155, Station Blackout, and NUMARC 87-00, Guidance and Technical Basis for NUMARC Initiatives Addressing Station Blackout as Light Water Reactors, Appendix D remains in effect within plant procedure 0PPP-17, Emergency Diesel Generator Reliability Program, the station's implementing procedure for emergency diesel generator reliability monitoring. While the addition of a non-safety related SUPP-DG will allow a longer out of service time to be utilized for the existing EDGs for corrective maintenance, it will not change or affect any of the current regulatory monitoring programs associated with the standby AC power source. The Maintenance Rule performance measure for unavailability provides a control mechanism on the usage of the extended CT. The Maintenance Rule requires an evaluation be performed when equipment covered by the Maintenance Rule does not meet its performance criteria. The reliability and availability of the EDGs are monitored under the Maintenance Rule program. If the pre-established reliability or availability performance criteria are not achieved for the EDGs, they are considered for 10 CFR 50.65(a)(1) actions. These actions would require increased management attention and goal setting to restore their performance to an acceptable level. The actual out-of-service time for the DGs is minimized to ensure that the reliability and availability performance criteria are met.

The 14-day CT will enhance EDG availability and reliability and BSEP will continue to meet the maintenance rule availability/reliability requirements, and the reactor oversight process performance indicator criteria for emergency diesel generator availability/reliability.

NRC Question10

The submittal indicates that a full-scope peer review was performed in 2010 for the internal probabilistic risk assessment (PRA) events. The LAR also indicates that the PRA model has been revised periodically and some of these revisions included changes to address findings from the past peer reviews.

a. Identify any changes made to the internal events PRA since the last full-scope peer review of the internal events PRA that are consistent with the definition of a "PRA upgrade" in ASME/ANS-RA-Sa-2009, as endorsed by Regulatory Guide 1.200.

b. Provide all findings and observations from the last independent peer review. Also, please describe how each finding was dispositioned for this application.

c. If any changes, since the independent peer review, are characterized as a PRA upgrade, please identify if a focused-scope peer review was performed for these changes consistent with the guidance in ASME/ANS-RA-Sa-2009, as endorsed by Regulatory Guide 1.200, and describe any findings from that focused-scope peer review and the resolution of these findings for this application.

d. If a focused-scope peer review has not been performed for changes characterized as a PRA upgrade, please describe what actions will be implemented to address this review deficiency and when the application will be supplemented to describe any findings from that focused-scope peer review and the resolution of these findings for this application.

Response to Question 10

a. Changes to the PRA model subsequent to the 2010 peer review are tracked in the PRA change log. Each change instituted for the EDG AOT model was reviewed relative to the definitions of PRA Maintenance and PRA Upgrade from ASME/ANS RA-Sa-2009 (i.e., ASME 1.200), Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications. None of the changes were an upgrade (i.e., ASME/ANS RA-SA-2009, section 1-A); rather all the changes were corrections.

b. The last independent internal event peer review was performed in 2010. All findings were dispositioned and included in the LAR enclosure 7, Peer Review F&O's (Table A7-1). All suggestions were related to documentation clarity and improvement. Per NEI guidance, there were no suggestions that would change the overall answer, or opinion of the LAR review. Further, a review of the peer review team's comments did not find any initial findings that were reduced to suggestions in the 2010 Peer Review.

During the 2011 peer review of the FPRA, one F&O was initially characterized as a Finding and, during the course of the peer review, was changed to a Suggestion in the final report. F&O 2-6 broadly concerned the validation and verification of the software tools. After being provided the software control procedures and the Appendix B calculation procedures, the peer review team did not have significant concerns over the tool V&V processes but continued to consider the documentation of the tool limitations to be lacking. Consequently, F&O 2 6 was changed to a suggestion concerning the documentation of both the benchmarking and limitations of FRANC (e.g. min-cut upper-bound issue) and the limitations and workarounds of in-house databases and Excel spreadsheets.

c. No changes were characterized as a PRA upgrade.

d. No changes were characterized as a PRA upgrade.

NRC Question 11

Enclosure 4, page 8, of the LAR provides a description of the changes made to the base PRA model to account for a SUPP-DG and 14 day completion time. The submittal indicates that a new test and maintenance (T&M) interval was added for each diesel generator (DG) while maintaining the existing T&M event. The submittal states this represents "14 additional days of unavailability." The NRC staff requests further clarification regarding how many days of unavailability are modeled in the base PRA and what time frames are used [to] calculate the delta core damage frequency (CDF).

Response to Question 11

New Basic Events (EDG1DGN-EXTTM-D001 and D002; EDG2DGN-EXTTM-D003 and D004) were implemented in the EDG Allowed Outage Time (AOT) model that corresponded to the extra 14 days of unavailability such that the entire unavailability period is the 14 days plus the base PRA model unavailability. The base PRA model unavailability is calculated over 11 years from 1998 to the end of 2008 and is documented in Revision 9 of the BNP data calculation (BNP-PSA-004). The base PRA model unavailability is shown in the table below. Note, UA is Unavailability and EF is Error Factor (EF).

From Table 9 of BNP-PSA-004 Revision 9

System	Name	Basic Event	UA Hours	Online Hours	Individual UA	Avg. UA	EF
EDG	Diesel Generator 1 U1	EDG1DGN-TM-D001	1458.1	89114	1.64E-02	1.63E-02	14.23
EDG	Diesel Generator 1 U2	EDG1DGN-TM-D001	1458.1	89674	1.63E-02	1.63E-02	14.23
EDG	Diesel Generator 2 U1	EDG1DGN-TM-D002	1525.4	89114	1.71E-02	1.71E-02	14.23
EDG	Diesel Generator 2 U2	EDG1DGN-TM-D002	1525.4	89674	1.70E-02	1.71E-02	14.23
EDG	Diesel Generator 3 U1	EDG2DGN-TM-D003	1211.7	89114	1.36E-02	1.36E-02	14.23
EDG	Diesel Generator 3 U2	EDG2DGN-TM-D003	1211.7	89674	1.35E-02	1.36E-02	14.23
EDG	Diesel Generator 4 U1	EDG2DGN-TM-D004	1223.7	89114	1.37E-02	1.37E-02	14.23
EDG	Diesel Generator 4 U2	EDG2DGN-TM-D004	1223.7	89674	1.36E-02	1.37E-02	14.23

Note that base PRA model unavailability without the 14 day addition is tracked against a single unit; hence a single diesel will have two unavailabilities, one for each unit at BSEP.

NRC Question 12

Enclosure 7, page 1, of the LAR indicates that the 2010 peer review found supporting requirement (SR) IE-A5 not met because a systematic evaluation was not performed for systems other than mitigating systems to assess the possibility of an initiating event occurring. Provide a more comprehensive list of additional systems and support systems evaluated to determine initiating event occurrences.

Response to Question 12

A systematic evaluation assessing systems for the possibility of an initiating event occurring is documented in the BNP Initiating Events Calculation (i.e., BNP-PSA-032, Revision 9) and are presented below.

System	Description	IE Disposition
0000	MISCELLANEOUS	No new initiator impact.
1005	B21,B11-RX VESSEL & INTERNALS	Subsumed by LOCAs.
1011	A71-NUCLEAR STM SUP SHUTOFF	Partial closure of an MSIV would result in a trip. Subsumed by the turbine trip initiator.
1050	C51-NEUTRON MONITORING SYSTEM	No new initiator impact.
1065	C11-ROD CONTROL SYSTEM	Inadvertent rod withdrawal or insertion could result in a plant trip or ATWS. Initiator added.
1070	C11,C12-CNTRL ROD DRIVE HYDRL	Potential Trip Impact. Loss of flow results in a plant trip. Initiator subsumed by loss of control rod system.
1080	C71-REACTOR PROT SYS (RPS)	Potential for a RPS fault to induce a trip. Subsumed by Turbine trip.
2010	G31-REACTOR WTR CLEAN-UP RWCU	System malfunction can impact chemistry such that a planned shutdown is needed but will not result in a trip/ initiating event.
2020	B32-REACTOR RECIRCULATION SYS	Trip of a recirculation pump would result in a Turbine trip. Subsumed by Turbine trip.
2035	E21-CORE SPRAY SYSTEM (CS)	Standby system. No new initiator impact.
2040	C41-STANDBY LIQUID CTRL (SLC)	Malfunction of this backup system could result in negative reactivity insertion but wouldn't be considered a reactor trip or initiating event

2045	E11-RESIDUAL HEAT REMOVAL SYS	Standby system. No new initiator impact.
2055	B21,B21C-AUTO DEPRESSURIZATION	Spurious opening of an SRV would result in a trip. Initiating Event %^T_S was developed to address inadvertent opening of SRV.
2070	CAC-CONTAINMENT ATMOS. CTRL	No new initiator impact.
2095	E41-HIGH PRESS COOLANT (HPCI)	Standby system. Potential for pipe break/flood initiator impact. Inadvertent startup would result in a Turbine trip. Subsumed by turbine trip.
2100	E51-REACTOR CORE ISOL COOLANT (RCIC)	Standby system. Potential for pipe break/flood initiator impact. Inadvertent startup would result in a Turbine Trip. Subsumed by turbine trip.
2115	RXS-REACTOR BLDG SAMPLING SYS	No new initiator impact.
2117	PASS, RXS-POST ACCIDENT SMPL	No new initiator impact.
2190	TD-TORUS DRAIN SYSTEM	No new initiator impact.
3020	MS-MAIN STEAM SYS (INC EHC)	Disturbance in main steam flow as a result of faulty turbine control could result in a turbine trip. Subsumed by turbine trip.
3025	EX-EXTRACTION STEAM SYSTEM	Loss or reduction of extraction steam to the feedwater heaters will cause a reduction in the temperature of feedwater entering the vessel and will raise reactor power. This failure is subsumed by the turbine trip transient initiator.
3030	MD, RHS –MSR DRN & REHEAT STM	No new initiator impact.
3040	AS-AUXILIARY BOILER SYSTEM	No new initiator impact.
3050	C32,FW-FEEDWATER SYSTEM	Disturbances in the feedwater system directly affect reactor power typically resulting in a trip. Subsumed by a loss of feed.
3060	HD,MVD-HTR DRN, MISC VENT&DRN	No new initiator impact.
3070	CO, CD, COR-COND & RET COND	Disturbances in the feedwater system directly affect reactor power typically resulting in a trip. Subsumed by a turbine trip.
3076	CFD-COND FLT DEMIN SYSTEM	Disturbances in the feedwater system directly affect reactor power typically resulting in a trip. Subsumed by a turbine trip.
3077	CDD,COD-COND DEEP BED&OUT DEMI	Disturbances in the feedwater system directly affect reactor power typically resulting in a trip. Subsumed by a turbine trip.
3080	MUD-COND MAKE-UP (INC MWT)	No new initiator impact.
3100	TS-TURBINE BLDG SMPL SYSTEM	No new initiator impact.
4005	CONDENSER	Loss of condenser vacuum results in a trip. Initiating event is developed as %^T_C to address the loss of Condenser.
4010	AR,OG-OFF GAS & CNDSR VACUUM	Loss of condenser vacuum results in a trip. Subsumed under the %^T_C initiator.
4015	CW-CIRCULATING WATER SYSTEM	Loss of Circ water will result in a loss of condenser vacuum resulting in a trip and is subsumed.
4040	SCW-SCREEN WASH SYSTEM	Clogging of all screens will result in a loss of service water and is subsumed.
4045	INTAKE & DISCHARGE CANAL	Potential trip impact if condition causes a loss of all service water pumps. Subsumed by loss of intake.
4060	SW-SERVICE WATER SYSTEM	Loss of Service Water (Conventional, Nuclear) could result in a plant trip. Initiator for the common cause failure. Subsumed by loss of

		intake.
4070	RCC-RX BLDG CLO COOL WTR SYS	Loss of RBCCW will result in loss of cooling to CRD pumps. More consideration required. A separate initiator for loss of RBCCW is included.
4075	TCC-TUR BLDG CLO COOL WTR SYS	Loss of TBCCW will result in a loss of feedwater pump and condensate pump cooling. A separate initiator for loss of TBCCW is included.
5005	TURBINE SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5010	EHC-TURBINE CTRL SYS (INC.TSI)	Potential turbine trip initiator. Subsumed by Turbine trip.
5020	TURBINE-GENERATOR LUBE OIL SYS	Potential turbine trip initiator. Subsumed by Turbine trip.
5025	GS,SS-GLAND SEAL & STM SEAL	Potential turbine trip initiator. Subsumed by Turbine trip.
5030	EXHAUST HOOD SPRAY SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5035	TURNING GEAR SYSTEM	No new initiator impact.
5040	GENERATOR SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5045	GENERATOR EXCITER SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5050	GENERATOR GAS SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5055	STATOR COOLING WATER SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5060	HYDROGEN SEAL OIL SYSTEM	Potential turbine trip initiator. Subsumed by Turbine trip.
5065	GENERATOR ISOLATED PHASE BUS	Potential turbine trip initiator. Subsumed by Turbine trip.
5075	24V DC BATTERY SYSTEM	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5080	24V DC BATTERY CHARGER SYSTEM	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5085	24/48V DC DISTRIBUTION SYSTEM	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5095	EDG-DIESEL GENERATOR SYSTEM	Standby system. No new initiator impact.
5098	SAMG DIESEL GENERATOR SYSTEM	Standby system. No new initiator impact.
5100	FOD, FO-DIESEL GEN FUEL OIL	Standby system. No new initiator impact.
5105	LO-DIESEL GEN LUBE OIL SYSTEM	Standby system. No new initiator impact.
5110	MUD-EDG JKT WTR & EDG DEMIN WTR	Standby system. No new initiator impact.
5111	SW-DIESEL GEN SERV WTR SYS	Standby system. No new initiator impact.
5112	DSA-DIESEL GEN STRT AIR SYS	Standby system. No new initiator impact.
5113	DIE-DIESEL GEN INTK/EXH SYSTEM	Standby system. No new initiator impact.
5135	230 KV SWITCHYARD (INC.MPT)	Potential for loss of off-site power. Trip for switchyard included.
5145	SAT,UAT-START-UP AUX.&AUX XFMR	AC power impact subsumed by system trips
5170	4 KV AC DISTRIBUTION SYSTEM	AC power impact subsumed by system trips
5175	480V AC DISTRIBUTION SYSTEM	AC power impact subsumed by system trips
5185	208/120 VAC DISTRIBUTION SYS	AC power impact subsumed by system trips
5195	UPS-UNINTERRUPTIBLE AC SYS	AC power impact subsumed by system trips
5200	24KV SWITCHYARD SYSTEM	AC power impact subsumed by system trips
5205	NACL-NORMAL AC LIGHTING SYS	No new initiator impact.
5210	EDCL-EMERGENCY DC LIGHTING SYS	No new initiator impact.
5215	EDCL-EMERGENCY DC LIGHTING SYS	No new initiator impact.

5230	250 VDC DISTRIBUTION SYSTEM	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5240	125 VDC BATTERY CHARGER SYS	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5245	125 VDC BATTERIES & BAT DIST	Potential impact from loss of DC Power. Subsumed under loss of DC switchboard.
5250	LIGHTNING PROTECTION SYSTEM	No new initiator impact.
5255	CATHODIC PROTECTION SYSTEM	No new initiator impact.
5259	SITE CABLES SYSTEM	No new initiator impact.
5260	SITE GROUNDING SYSTEM	No new initiator impact.
5265	HS-HEAT TRACING SYSTEM	No new initiator impact.
6002	TRAINING SIMULATOR	No new initiator impact.
6004	ERFIS COMPUTER SYS (INC. SPDS)	No new initiator impact.
6005	C91-PROCESS COMPUTER	No new initiator impact.
6010	H12,XU-MAIN CTRL BOARD (RTGB)	Potential trip impact. Subsumed by turbine trip initiator
6015	H12,H21-ANNUNCIATOR SYSTEMS	No new initiator impact.
6020	H21,IR-AUX.CONTROL BOARD	No new initiator impact.
6030	PA SYSTEM	No new initiator impact.
6035	COMMERCIAL PHONES & TELECOPIER	No new initiator impact.
6040	SPP – SOUND POWERED TELEPHONE	No new initiator impact.
6045	FCC LICENSED BASE RADIOS	No new initiator impact.
6055	FCC LICENSED PORTABLE RADIOS	No new initiator impact.
6060	MICROWAVE SYSTEM	No new initiator impact.
6070	P62-METEORLOGICAL & ENVIR	No new initiator impact.
6075	SEISMIC MONITORING SYSTEM	No new initiator impact.
6080	CASWELL BEACH SUPV. & CONTROL	No new initiator impact.
6085	SECURITY COMPUTER SYSTEM	No new initiator impact.
6095	CARD READER/ACCESS CTRL SYS	No new initiator impact.
6100	CLOSED CIRCUIT T.V. SYSTEM	No new initiator impact.
6105	INTRUSION DEVICES	No new initiator impact.
6115	SECUR FENCING,GATES, ACCESS PT	No new initiator impact.
6120	PHYSICAL SEARCH SYSTEM	No new initiator impact.
6125	KEY CTRL & HWD – SECUR,RAD	No new initiator impact.
6130	SECURITY COMMUNICATION SYSTEM	No new initiator impact.
6135	IA-INSTR AIR (IAI,IAN,RIA,RNA)	Loss of pressure will result in reactor trip due to condensate valves drifting closed. These are described with a loss of air initiator.
6140	SA-SERVICE AIR SYSTEM	Subsumed under loss of Instrument Air
6152	PNS-PNEUMATIC NITROGEN SYS	No new initiator impact.
6160	HP,HPH-HYDROGEN SUPPLY SYS	No new initiator impact.
6165	CP-CARBON-DIOXIDE SUPPLY SYS	No new initiator impact.
6175	FP- FIRE PROTECTION SYSTEM	No new initiator impact.
6180	FIRE DETECTION SYSTEM	No new initiator impact.
6195	FIRE PROTECTION CO2 SYSTEM	No new initiator impact.
6200	LO-LUBE OIL STR & XFER SYSTEM	No new initiator impact.
6202	FO-FUEL OIL SYSTEM	No new initiator impact.
6205	HALON SUPPLY SYSTEM	No new initiator impact.
6210	SEW-SEWAGE TREATMENT SYSTEM	No new initiator impact.
6215	SEWAGE,SANITARY AND ROOF DRN	No new initiator impact.
6220	DST-STORM DRAINS SYSTEM	No new initiator impact.
6221	GWE-GROUNDWATER EXTRACTION SYS	No new initiator impact.
6225	OIL DRAINS SYSTEM	No new initiator impact.
6235	G16-RADIOACTIVE FLR DRN SYSTEM	No new initiator impact.

6240	G16-RADIOACTIVE EQUIP DRN SYS	No new initiator impact.
6245	LAUNDRY & HOT SHOWERS SYSTEM	No new initiator impact.
6260	WATER TREAMENT (INC. CG,CS,CV)	No new initiator impact.
6261	CL-CHLORINATION (INC. CG,CS,CV	No new initiator impact.
6264	SHI-SODUIM HYPOCHLORITE INJECT	No new initiator impact.
6265	PW,PWT-POTABLE WATER SYSTEM	No new initiator impact.
6270	DW-DEMINERALIZED WATER SYS	No new initiator impact.
6280	CA-CAUSTIC SYSTEM	No new initiator impact.
6281	HWC,HWCH,HWCO-HYDROGEN WTR	No new initiator impact.
6282	AC-ACID SYSTEM	No new initiator impact.
6300	DICSP-DISTRIB I&C SYS-PLATFORM	No new initiator impact.
6305	PNET-PROCESS NETWORK	No new initiator impact.
7005	D12-PROCESS RAD MONITORING SYS	No new initiator impact.
7015	D22-AREA RAD MONITORING SYSTEM	No new initiator impact.
7045	G16-SOLID WASTE PROCESSING	No new initiator impact.
7060	G16-LIQUID WASTE PROCESSING	No new initiator impact.
7070	AOG-AUGMENTED OFFGAS SYSTEM	No new initiator impact.
7071	SGT-STANDBY GAS TREATMENT SYS	No new initiator impact.
7075	RS-RADWASTE SAMPLING SYSTEM	No new initiator impact.
7095	F11,F12,F14,F15-REFUELING SYS	No new initiator impact.
7100	F13,F17-RX VESSEL SERV EQUIP	No new initiator impact.
7105	F16-SPENT FUEL SYSTEM	No new initiator impact.
7110	G41,G42-FUEL POOL COOL SYSTEM	No new initiator impact.
7111	J11 – NUCLEAR FUELS INC.	No new initiator impact.
7127	DRY SPENT FUEL STORAGE	No new initiator impact.
8020	PRIMARY CONT. (INC.LINER&PENE)	No new initiator impact.
8035	RLYBLDG-RELAY BUILDING	No new initiator impact.
8040	CASBCH & OCEAN DISCH BLDG	No new initiator impact.
8045	GROUNDS MAINTENANCE/LANDSCAPE	No new initiator impact.
8055	MONORAIL HOISTS	No new initiator impact.
8065	BRIDGE CRANES	No new initiator impact.
8075	VA-HVAC DIESEL GENERATOR BLDG	Loss of HVAC will not result in an immediate trip
8085	CLEAN MAINTENANCE SHOP	No new initiator impact.
8110	RCC-PENETRATION COOLING SYS	No new initiator impact.
8120	TRAILERS	No new initiator impact.
8135	FIREHOUSE	No new initiator impact.
8185	VA-HVAC REACTOR BUILDING	Loss of HVAC will not result in an immediate trip
8195	GANTRY CRANES	No new initiator impact.
8220	VA-HVAC CONTROL BUILDING	Loss of HVAC will not result in an immediate trip
8230	SWB-SERVICE WATER BLDG	No new initiator impact.
8232	VA-HVAC SERVICE WATER BLDG	Loss of HVAC will not result in an immediate trip
8240	REACTOR BUILDING	No new initiator impact.
8247	VFD-VARIABLE FREQ DRIVE BLDG	No new initiator impact.
8250	VA-HVAC SERVICE BUILDING	Loss of HVAC will not result in an immediate trip
8260	VA-HVAC TURBINE BLDG	Loss of HVAC will not result in an immediate trip
8270	OGB-AUGMENTED OF GAS BLDG(AOG	No new initiator impact.
8275	HMS-HOT MAINT SHOP&STOREROOM	No new initiator impact.
8280	VA-HVAC RADWASTE BLDG	Loss of HVAC will not result in an immediate trip
8285	MICROWAVE BLDG	No new initiator impact.
8290	CHLORINATION BUILDING (CLB)	No new initiator impact.
8291	OPERATIONS OFFICES	No new initiator impact.
8300	ADM-ADMINISTRATIVE BLDG	No new initiator impact.
8306	TSC/EOF/TTC TRAINING BUILDINGS	No new initiator impact.
8307	TAC-TECHNICAL AND ADMIN BLDG	No new initiator impact.

8310	AXB-AUXILIARY BOILER HOUSE	No new initiator impact.
8340	DGB-DIESEL GENERATOR BLDG	No new initiator impact.
8355	CTB-CONTROL BUILDING	No new initiator impact.
8360	SVB-SERVICE BUILDING	No new initiator impact.
8370	TB1,TB2-TURBINE BUILDING	No new initiator impact.
8380	WHS-WAREHOUSES (C,H,B, ETC.)	No new initiator impact.
8390	RWB-RADWASTE BUILDING	No new initiator impact.
8400	MWT-WATER TREATMENT BLDG	No new initiator impact.
8435	OIL & PAINT STORAGE BLDG	No new initiator impact.
8500	ELE-ELEVATOR SYSTEM	No new initiator impact.
8510	SITE ROADS AND PARKING LOTS	No new initiator impact.
8515	SITE RAILROAD SPURS	No new initiator impact.
8565	DCB-DOCUMENT CONTROL BLDG	No new initiator impact.
8580	MISC STRUCTURES OR OUT BLDG	No new initiator impact.
8590	INCINERATOR	No new initiator impact.
8595	LANDFILL	No new initiator impact.
9000	NON-EQUIPMENT SYSTEMS	No new initiator impact.
9015	HEALTH PHYSICS EQUIPMENT	No new initiator impact.
9021	SITE PERSONAL COMPUTERS	No new initiator impact.
9022	SITE LOCAL AREA NETWORK(LAN)	No new initiator impact.
9023	SITE BAR CODE SYSTEM	No new initiator impact.
9024	VIDEO INFORMATION SYSTEM	No new initiator impact.
9025	RADIO CHEMISTRY EQUIPMENT	No new initiator impact.
9030	SAFETY EQUIPMENT	No new initiator impact.
9035	PLANT VEHICLES	No new initiator impact.
9040	GENERAL I&C SPARES	No new initiator impact.
9041	GENERIC ENVIRONMENTAL QUALIF	No new initiator impact.
9045	GENERAL MECHANICAL SPARES	No new initiator impact.
9071	INSULATION SHOP EQUIPMENT	No new initiator impact.
9075	HOT MACHINE SHOP EQUIPMENT	No new initiator impact.
9895	SEISMIC DOCUMENTATION-NONEQUIP	No new initiator impact.
9901	SHIELDING- FOR PM CONVERSION	No new initiator impact.
9991	ANALYSIS SOFTWARE	No new initiator impact.
9992	OSI PI	No new initiator impact.

NRC Question13

Enclosure 7, page 3, of the LAR indicates SRs HE-E3 and HE-E4 are not Capability Category (CC) II due to lack of evidence of detailed operator interviews. For this application, a new operator action is added to reflect the actions necessary to start and align the SUPP-DG to the applicable emergency bus. Five related critical operator actions are listed in Enclosure 4, page 10. Provide a brief summary of operator interviews and input gained from site operations to assess these operator actions.

Response to Question 13

The five operator actions noted in the EDG LAR are execution steps combined under a single human reliability analysis (HRA). Operator interviews were conducted and insights were noted in the form used for reliability analysis. Pertinent information about the actions and the insight gleaned from an SRO qualified individual are contained in the interview sheet below:

Plant: BNP Unit 1 / 2 Interviewer(s): M. Humphrey Interviewee(s): D. Bain	HRA: BNP EDG LAR, OPER-SDGSTART Date: 11/27/12 Organization: Operations Management

Brief Description of HFE Scenario

During a 14 day diesel outage, the plant has readied the Supplementary Diesel Generator (SUPP-DG) electrical alignment. A Loss of Offsite Power (LOOP) occurs and there are enough failures of the other diesel generators that the SUPP-DG is needed (i.e., potential SBO). This HRA encompasses the actions needed to startup the SUPP-DG. The SUPP-DG must be manually started and tied to the applicable bus. This involves prevention of auto start loads, closing the applicable breakers, starting the SUPP-DG, and then closing the breaker to align it to the emergency bus.

Timing actions

Timing of Cue(s): The first cue is the LOOP which immediately sends the operators into the LOOP procedure and potentially into the station blackout (SBO) procedure.

Description of cue(s): On top of the LOOP which is an easy cue, the loss of AC Bus voltage, and the procedural requirements in an SBO scenario will drive operations to perform the actions. Further before the accident, Operations will have special briefing about the special EDG lineup and the use of the SUPP-DG during loss of power events.

Time available for action: 2 hours (battery capability time)

Time required for action to be performed: 45 minutes (cognitive + manipulation)

Delay between cue and start of action: 8 minutes

Procedures: To be incorporated into the AOP-36.0 procedure

Actions

Location of action: DG building, Turbine Building, Control room, SUPP-DG structure

Who performs: AO/RO

Difficulty of actions: Most difficult action is removing control power fuses at 4160V switchgear (i.e., removing fuse blocks at 4160V breakers using handle on fuse block, removing individual fuses at protective relaying panel using fuse pullers).

Training (or actual performance): Training has been planned and a special simulator (i.e., stand-alone-trainer of the SUPP-DG Engine Control Panel) will be used to train operations personnel.

Performance shaping factors

Lighting: flashlight and/or emergency Smoke: No Tools: Y (gloves, fuse pullers) Clothing: No Plant Response: No	Heat: No Spatial: No Parts: No Complexity: High Workload: High

Other Comments
During external events, the SUPP-DG structure may be inaccessible because it is outside, away from the turbine building. This HRA is strictly for scenarios that do not involve blocked paths.

The performance shaping factors are generally where a lot of insight is found when talking with operators. During the use of the SUPP-DG, the AC lighting system would most likely not be available, and the actions would require some form of emergency or handheld lighting. There is no special dress out clothing involved and operators carry gloves with them to perform the actions. Fuse pullers are also needed for added safety when removing individual fuses and are pre-staged in an equipment tool bag for the task. Heat and smoke are attributed to fire, but the operators should not be in direct danger from these sources unless the fire was in the same room, which fails the equipment anyway. During the evolution, operators in the control room may be in several procedures at once, therefore a shaping factor for workload is considered High. Finally, the actions are collaborated over three buildings and require more than simple switches or button presses. This increases the complexity shaping factor to High which impacts the execution success.

NRC Question 14

Enclosure 7, page 5, of the LAR indicates SR DA-C8 is not CCII because of the methodology used to characterize system standby times. CCII requires plant-specific operational records to determine time that components are configured in their standby status. The licensee provides a brief statement in the LAR stating that an investigation determined the results gained from the estimates are realistic. Provide the plant-specific basis used to estimate the standby times for diesel generators.

Response to Question 14

The Finding and Observation (F&O) was directed at the method for setting up a plant alignment for use in accident scenarios. In the base PRA and EDG AOT models, mitigation equipment such as the diesels have no initial state flags. Thus the test and maintenance unavailability alone determines the unavailability. The standby time for a diesel can then be expressed as:

Standby Time = 1-Unavailability

The standby times for diesel generators below are from the base PRA Data notebook (i.e., BNP-PRA-004, Revision 9). The data for the unavailability is gleaned from plant specific sources such as the maintenance rule, and compared with the Mitigating System Performance Index to ensure applicability. The table below contains the values applicable to the EDG AOT model:

Diesel	Unavailability (averaged between units)	Availability
EDG 1	1.63E-02	9.84E-01
EDG 2	1.71E-02	9.83E-01
EDG 3	1.36E-02	9.86E-01
EDG 4	1.37E-02	9.86E-01

NRC Question 15

Enclosure 7, page 7, of the LAR indicates SR QU-D1 is not met because the licensee failed to properly review a sample of significant cutsets. Clarify how the review was improved and how many CDF and LERF cutsets were analyzed.

Response to Question 15

As documented in Revision 10 of the quantification calculation (i.e., BNP-PSA-030, section 3.7) the CDF and Large Early Release Frequency (LERF) review was improved and expanded to include:

- Discussion of the metrics the model review team used to determine the quality of the cutsets.
- The number of top cutsets reviewed. The team reviewed the top 200 cutsets, 100 of which are documented in the quantification calculation.
- Discussion of review for significant accident sequences. Accident Sequences that aggregate up to 95% of CDF were reviewed similar to the top cutsets for consistency and to ensure significant cutsets show up appropriately and are valid.
- Comparison of the model results between the new model and old were documented.
- Documentation included model trends and areas of future improvement.

Based on the expanded review and documentation, we consider that the improvements meet Capability Category II of the ASME 1.200 Standard, QU-D1

NRC Question16

Enclosure 7, page 7, of the LAR indicates SR QU-D4 is not met because the licensee failed to identify causes for significant differences in results to other similar plants. The licensee states that the model is revised to include an enhanced similar plant review. Provide any significant differences found during this review associated with cutsets related to diesel generators.

Response to Question 16

An enhanced review was conducted in the quantification calculation (i.e., BNP-PSA-030, Revision 10) to correlate the initiating events with other similar plants. Initiating events are a good measure for comparison since the plants often have unique features that create difficulties in finding applicable insights by comparing at the cutset level. In BSEP's case, the diesel generators and the electrical system are unique in their cross-connect ability which can create results that would not be easily comparable and little insight would be gained in a comparison at the cutset level.

NRC Question 17

Enclosure 7, page 9, of the LAR indicates SR LE-E1 is met; however, the finding suggests that offsite power (OSP) recovery values are not consistent with the current OSP recovery curve. The licensee states that the LOSP curves and component failures are now updated. Provide an assessment that shows OSP recovery values are consistent between Level 1 and 2 data.

Response to Question 17

Revision 4 of the Level 2 Analysis calculation (i.e., BNP-PSA-049) evaluates the Level 2 OSP recovery value. A weighted average OSP recovery curve was created from the recovery curves used in Level 1 as documented in the Level 1 system initiating events notebook (i.e., BNP-PSA-032). The Level 2 recovery timeframes were applied to the Level 2 offsite power recovery curve to find the resultant recovery probability. By using the data from Level 1 to construct the Level 2 curve, the Level 2 probability is considered consistent with the Level 1 probability for a given timeframe.

NRC Question 18

Enclosure 7, page 10, of the LAR lists twenty six internal flooding supporting requirements as not met to CC I and each of these findings is dispositioned by the licensee as resolved. Enclosure 5, in response to peer review findings, notes that significant flooding scenarios were examined for realism and some adjustments were made based upon material of piping and design attributes. As highlighted in the previous RAI, the licensee should address if those examination and adjustments made to the internal flooding model constitutes a PRA upgrade. If a PRA upgrade is warranted, provide the staff the results of a focused-scope peer review for the internal flooding PRA. Otherwise, address each internal flooding finding more specifically than the generic disposition provided in the LAR since the staff cannot make a determination on the adequacy of the internal flooding PRA model based on the information provided.

Response to Question 18

Each F&O was compared to the ASME/ANS RA-Sa-2009 (i.e., ASME 1.200) Standard to determine if the resolution to the F&O summary would constitute change in capability, an increase in scope or a change in methodology, and hence an upgrade. The peer review was performed to demonstrate that the BSEP Flooding PRA capability would support risk-informed applications. In general, the change in capability was addressed by the peer review and the resolution of the peer review comments would not constitute an additional change in capability. In a similar manner, the resolution of peer review comments would not be an increase in scope. The bases to conclude that these resolutions do not constitute an upgrade are provided in the following table for each item.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-21	IFSO-A1	Cat 1-3 Not Met	The fire protection system is stated to be dry pipe when most are wet pipe.	RSC 10-05 R1 corrects the initial information that identified the fire protection system as pre-actuated. The revised analysis includes fire protection piping for both flooding (i.e., reference Table F.3) and for spray effects (i.e., reference Table F.22). Potential pipe breaks, pipe break frequency, flow rates and flooding/spray impacts are included in the revised analysis. Fire protection piping was added but using the same approach as for other pipe related faults so no new methods were applied. This is a completeness issue and not an increase in scope.
1-22	IFSO-A4	Cat 1-3 Not Met	Gasket and expansion joints are not discussed	RSC 10-05 R1 adds Section F.12 to specifically address gasket and expansion joint failures. The listed flooding sources were developed based on walkdown information and plant information. Frequencies and consequences based on flow rates assuming pipe diameter. Gasket and expansion joints were added to the assessment using a similar approach as for piping and no new methods defined. This is a completeness issue and not an increase in scope.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-23	IFSO-A5	Cat 1-3 Not Met	The temperature and pressure influences not documented in model along with pump flow rates for circulating water	Pressure and flow rates are specifically addressed in the analysis of the flow rate and are listed in Table F.12. The flow rate is either the maximum possible flow based on break size or the maximum due to pump run out conditions. Temperature is considered with regard to the likelihood of a HELB impact which is documented in Section F.11. Table F.24 provides a listing of expected zone temperature and pressure following postulated HELB pipe breaks. Prior flooding scenarios were divided into High Energy Line Break (HELB) and non-HELB. The condition for HELB was consistent and most all pipes were previously modeled as flood events. No new methods although different failure criteria based on environmental effects of exposure.
1-24/ 1-31	IFSO-B1	Cat 1-3 Not Met	The level of detail for flooding sources is not part of documentation although it exists in vendor database.	The documentation has been expanded to include Table F.7 which lists all sources for all zones, Table F.12 lists the parameters utilized to calculate flow rates, Annex A which provides the detailed information for flooding sources. Spray parameters are found in Table F.21 and Table F.22. No new methods; only incorporated new information into the documentation from the TIFA (i.e., contractor software database).
1-25	IFSN-A2	Cat 1-3 Not Met	No documentation for flood alarms, blowout panels or Heating, Ventilation, and Air Conditioning (HVAC) dampers.	The potential for room propagation includes the potential for HVAC dampers or panels to fail. For the specific arrangement of the BSEP facility this was not found to be a significant concern since water accumulation in confined areas for the most part is not present at elevations above the bottom level. The HRA calculator inputs define the cues needed to initiate response and this includes explicit consideration of available alarms. No new methods applied. This is a completeness issue and not an increase in scope.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-20	IFSN-A3	Cat 1-3 Not Met	Alarms and operator actions need to be identified	See answer to 1-25
1-24	IFSN-A5	Cat 1-3 Not Met	Documentation of Ricky Summit Consulting (RSC) database with regard to equipment in zones	The expanded the walkdown documentation and added Table F.5 and Table F.6 to document the targets included in the model. Integration of TIFA software information into the documentation.
6-16	IFSN-A6	Cat 1-2 Not Met	Assessment of spray and HELB	Section F.10 and Section F.11 address spray and high energy line break considerations and were added in response to this F&O. The spray analysis utilizes a spray radius of 20 ft in that any pipe within 20 ft of an identified vulnerable target was examined for spray impacts. The HELB analysis utilized a deterministic assessment of HELB vulnerability to define the areas subject to HELB and this was mapped to the associated HELB piping to define the HELB scenarios. Spray events and HELB were included as flooding events. Criterion for failure altered by refinement to spray and HELB is that submergence is not required so time to failure is not as long in many cases. This is a completeness issue and not an increase in scope.
1-26	IFSN-A8	Cat 1 Met Cat 2 Not Met	Flow paths not associated with doors, grates, openings	The walkdown documentation identifies paths listed in the documentation when it was found to exist. For example, louvers in the condensate booster pump room can allow water to flow into the turbine building entry hall. For the specific design of BSEP, however, there are adequate open stairwells, grates and other openings for most all areas that significant accumulation to these openings is not credible. The documentation of possible paths in Section F.7 identifies the plausible flow paths and propagation zones. No new methods or analysis. This is a completeness issue and not an increase in scope.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-27	IFSN-A11	Cat 1-3 Not Met	Flooding between units	The comments related to the turbine building were examined and the interfaces were adequately addressed. Although communication is possible between the units in the turbine building, the reviewer did not identify that there are closed doors between Unit 1 and Unit 2 at the ground level which must fail to allow flow to the opposite unit. Before this can occur, the breezeway hall rollup doors to the outside would be expected to fail and to relieve the water since it is a less restrictive door type that is present between the two units. As is described in Section F.7 water cannot accumulate in the turbine building at the 20 ft elevation due to the presence of stairs without curbs that allow water to flow down to the 0 ft level. The documentation has now included these considerations. Section F.1.3 lists assumptions related to the study in general and the propagation paths in specific. No new methods or analysis. The existing information is consistent with the design.
6-18	IFSN-A13	Cat 1-3 Not Met	Drain reliability and chance for clogging	The floor drains are not credited in terms of dewatering calculations due to the lack of accumulation above the lowest plant levels in reactor building and turbine building. Only power sump pumps were credited which are periodically tested. An assumption on drains has been added. No new methods or altered analysis. The current assessment is consistent.
1-28	IFSN-A16	Cat 1 Not Met	Lack of documentation related to 8 hour mitigation time	The documentation has been expanded to address reliability mitigation. Plant walkthrough requirements would result in identification either by security staff or operations staff. No new methods. Based on plant standard processes.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-31	IFSN-B1	Cat 1-3 Not Met	Documentation of propagation pathways	The documentation related to pathways has been expanded including new figures for pathways in the turbine building and explicit listing of zone to zone propagation in Table F.14. Documentation expanded.
1-31	IFSN-B2	Cat 1-3 Not Met	Documention of IFSN-A (c) (d) (e) (f) and impacted components	Assumptions for the screening (c) are provided in Section F.1.3, Screening criteria (d) are described in the methods section and in F.9. Retained scenarios (e) are found in Annex B and Annex C. The modifications to the model (f) are found in Table F.9 for direct faults and the fault tree (i.e., model of record). The specific components assumed failed by each scenario has been added to the report in Section F.9 and for spray in Annex C. Documentation expanded and assumptions listed.
1-27	IFEV-A4	Cat 1-3 Not Met	Use of Older Electric Power Research Institute (EPRI) Methodology/Data	Updated the BSEP study to utilize the more recent database for pipe break frequency (i.e., EPRI TR-1013141). The results from the updated flooding model have the same scenarios, although they moved up in overall internal events importance. The scenarios are not a large contributor to the EDG cutsets or the Loss of Offsite Power frequency
6-15	IFEV-A5	Cat 1-3 Not Met	Use of Older EPRI Methodology/Data	Updated the BNP study to utilize the more recent database for pipe break frequency (i.e., EPRI TR-1013141). The results from the updated flooding model have the same scenarios, although they moved up in overall internal events importance. The scenarios are not a large contributor to the EDG cutsets or the Loss of Offsite Power frequency.
3-14	IFEV-A6	Cat 1 met Cat 2-3 not met	Plant-specific data	Updated the BSEP study to include documentation on plant specific events and their contributions. Plant specific data was included in the analysis. No new methods were incorporated, based on standard processes.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
1-31	IFEV-B1	Cat 1-3 Not Met	Review not completed	The documentation has been added in F.5 and F.6 to address this comment. Documentation addition.
1-31	IFEV-B2	Cat 1-3 Not Met	Documentation not clear in identifying the Human Error Probabilities (HEPs) that potentially mitigate floods. Operating experience is not documented.	An updated HRA section F.13 has been added that improves HRA documentation and provides guidance as to the application and insertion of Human Failure Events (HFEs) into the analysis. Documentation improvement.
2-9	IFQU-A1	Cat 1-3 Not Met	The documentation does not provided in relation to identified flooding sequences and direct effects. Direct fault impacts are modeled in what manner?	Table F.19 was added to the report documentation to explicitly address this question on flooding impacts. The assumed loss of equipment is provided along with any isolation considerations. In some cases no credit is taken for system recovery as noted. No change in methods
1-32	IFQU-A2	Cat 1-3 Not Met	No documentation of link between flooding Initiating Events (IEs) and equipment failed by initiator.	Retained scenarios (e) are found in Annex B and Annex C. The modification to the model (f) are found in Table F.9 for direct faults and the CAFTA model of record.
2-10	IFQU-A5	Cat 1-3 Not Met	HRA issues due to limited assessment time	HRA documentation was updated and expanded to include a Cause-Base-Decision-Tree-Method (CBDTM) which is a standard method applied throughout the BSEP internal/external events. Method is consistent with widely used human reliability analysis and does not constitute an upgrade
6-13	IFQU-A6	Cat 1-3 Not Met	Flooding effects on HRA	This has been specifically addressed with respect to flood areas where operator action would be precluded by the flood or by an inability to get to the desired location. This is documented in Table F.26. No change in methods, just more detail.
1-33	IFQU-A9	Cat 1-3 Not Met	Direct effects were included. Only indirect effect was submergence.	Documentation updated to include HELB and spray effects. Increased documentation.

F&O Number	Applicable SR	Peer Review Capability Category	Finding Summary	Resolution
6-14	IFQU-A10	Cat 1-3 Not Met	LERF Model impacts	Failures of equipment due to submergence or other impacts are addressed. No new direct failure modes for isolation were identified. Method consistent for inclusion of failure modes directly into the isolation model through the fault tree logic.
6-17/ 6/21/ 1-31	IFQU-B1	Cat 1-3 Not Met	Lack of documentation on incorporation of flood results into the model.	Annex B and C provide the retained scenario impacts in regard to frequency, location and impact zones/equipment. No new methods.

NRC Question19

Enclosure 1, page 15, of the LAR notes an elevated foundation to protect the SUPP-DG system from flood and storm surge. Provide the height of the elevation and the determination used to establish this value such as historical flood records or calculated estimates.

Response to Question 19

The elevated foundation is at elevation 30.5 feet which is 10.5 feet above the 20.0 feet grade elevation in the area. The elevated foundation is 4.9 feet above the maximum instantaneous water level from flood.

The Updated Final Safety Analysis Report (UFSAR) design basis flood level from the Probable Maximum Surge and Seiche Flooding (i.e., Section 2.4.5) is 22.0 feet above MSL. This is coupled with wave action and run-up for a maximum instantaneous water elevation of 25.6 feet.

NRC Question 20

Enclosure 7, page 83, of the LAR lists examples by the peer review of omitted justifications for several partitioning elements that lack fire resistance rating. If applicable, provide justification or clarification for partitioned elements that lack fire resistance rating for fire areas that involve diesel generators or the supplemental diesel generator.

Response to Question 20

With the exception of Fire Area "DG-16E," Fan Room Extended, calculation BNP-PSA-083 partitioned the Diesel Generator Building into Fire Compartments that are identical to the Fire Areas defined in the Fire Hazard Analysis, UFSAR Section 9.5.1.5. Being so defined in a regulatory context, these Fire Areas were considered to satisfy the criteria for Fire Compartments in the context of the FPRA, consistent with the guidance in Section 1.5.2 of NUREG/CR-6850, EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities, Volume 2 Detailed Methodology, with no further justification of the associated partitioning elements. As described in UFSAR Section 9.5.1.5, Fire Area "DG-16E," Fan Room Extended, comprises five Fire Zones. BNP-PSA-083 partitioned the Fire Area "DG-16E," Fan Room Extended, into five FPRA Fire Compartments, corresponding to those five Fire Zones, to permit a finer resolution in the evaluation of the potential for formation of a hot gas layer. Some partitioning elements are credited either with a 3-hour fire resistance rating or as being capable of withstanding the expected fire exposures. However, UFSAR Section 9.5.1.5 credited no, or only partial, fire resistance for the following partitioning elements of these five Fire Compartments:

- Fire Compartment FC252 is equivalent to Fire Zone DG-15, Supply Air Plenum (50ft). The associated partitioning elements that lack a fire resistance rating are a concrete beam and slab floor, a concrete beam and slab ceiling, and concrete block walls on the north, east, and south.
- Fire Compartment FC253 is equivalent to Fire Zone DG-16, Diesel Building Supply Fan Room (50ft). The associated partitioning elements that lack a fire resistance rating are a concrete beam and slab ceiling, a reinforced concrete wall to the west, and concrete block walls on the north and south. Major portions of the north and south walls contain air filters to the outside.

- Fire Compartment FC254 is equivalent to Fire Zone DG-17, Diesel Building North Air Lock (50ft). The associated partitioning elements that lack a fire resistance rating are a concrete beam and slab ceiling, a reinforced concrete wall to the north, and concrete block walls on the south and on the east.
- Fire Compartment FC255 is equivalent to Fire Zone DG-18, Diesel Building South Air Lock (50ft). The associated partitioning elements that lack a fire resistance rating are a concrete beam and slab ceiling, a reinforced concrete wall to the north, and concrete block walls on the south and east.
- Fire Compartment FC260 is equivalent to Fire Zone DG-23, AFFF System Room (50ft). The associated partitioning element that lacks a fire resistance rating is a concrete beam and slab ceiling.

BNP-PSA-083 provided the technical basis to justify crediting the partitioning elements of these Fire Compartments as being capable of substantially containing the damaging effects of fire and documented the walkdown to confirm the existence and integrity of the credited partitioning features/elements. In particular, BNP-PSA-083 described a review of Fire Barrier Drawings and General Arrangement Drawings which indicated that all concrete wall/ceilings/floors credited by the Fire PRA Model (FPRA) were greater than four inches thick. These were comparable to the four inches thick concrete wall that was cited, in Section 1.5.2 of NUREG/CR-6850, Volume 2, as an example of an adequate partition for defining a one-hour fire endurance rating in the Fire PRA context. Also as documented in BNP-PSA-083, the walls formed of the concrete block required by BSEP Design Specification 029-001 were credited with a fire resistance rating of 2 hours, based on the National Concrete Masonry Associated TEK 7-1C.

The supplemental diesel generator is located northwest of the plant in an outside area which comprises, together with other outside areas, Fire Compartment FC263. The primary partitioning element for structures and equipment located in Fire Compartment FC263 is spatial separation. As evident from EC 87088, the supplemental diesel generator is separated from other structures and equipment of interest by at least 30 feet.

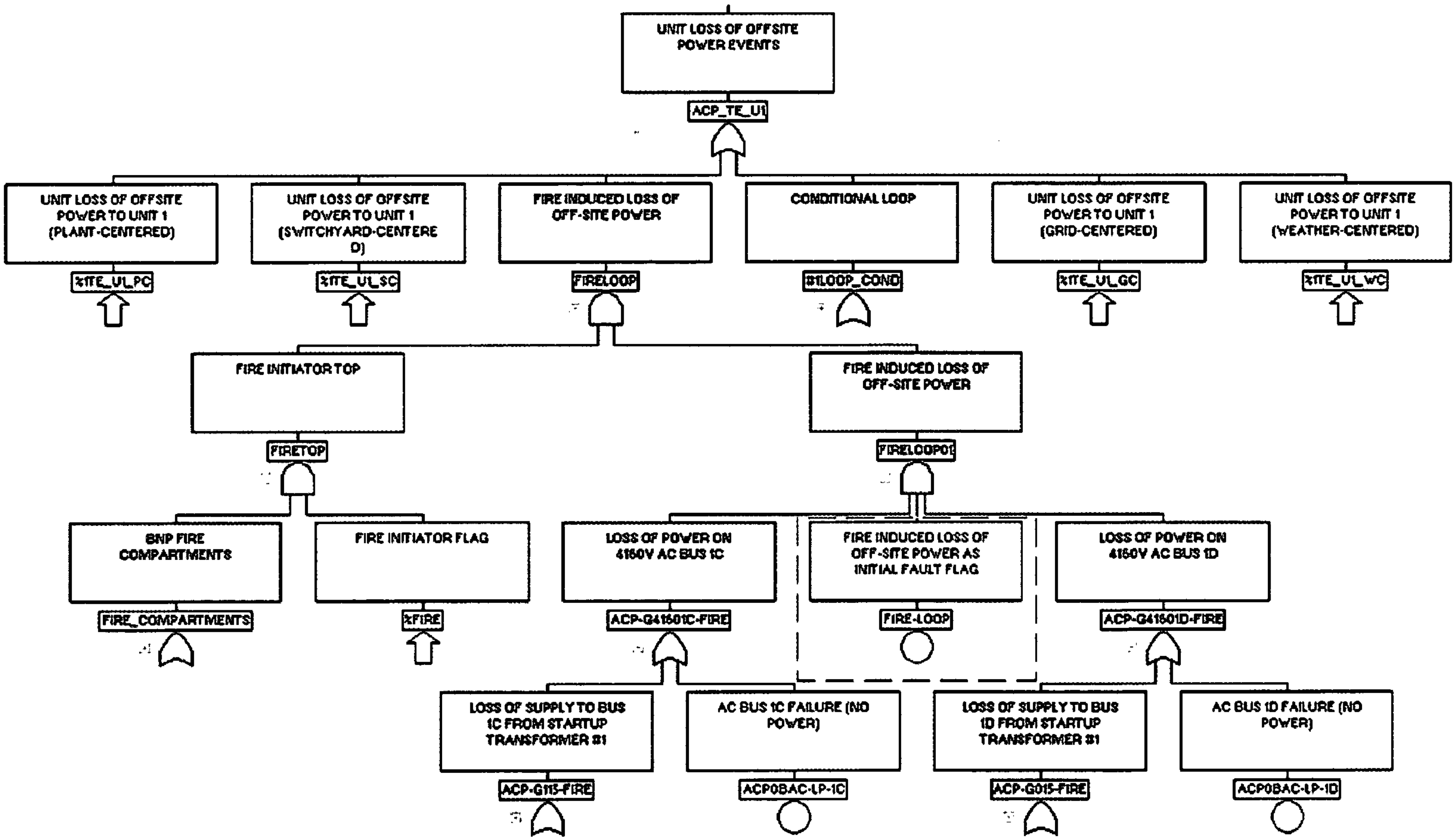
NRC Question 21

Enclosure 7, page 48, of the LAR states that the Fire PRA model does not include mapping of initiating events to specific equipment such as loss of DC power and offsite power. The peer review further notes that review of LOOP logic indicates several locations where consequential LOOP was not included. The licensee's assessment found that all initiating events had been adequately addressed except for fire induced loss of offsite power (LOOP) and therefore logic for fire induced LOOP was added to the fault tree where appropriate. Provide the tracing performed to identify the equipment affected due to fire-induced loss of DC power. In addition, further describe the fault tree logic added to the model to address fire induced LOOP and consequential LOOP.

Response to Question 21

To identify the equipment affected due to fire-induced loss of DC power, DC power dependencies were explicitly modeled in the fault tree. During component selection, particular basic events were mapped to particular equipment failure modes. A number of circuit analyses were performed to identify specific cables associated with the relevant failure modes for the modeled equipment, and the results were added to an existing database that is used for safe shutdown analysis. The cable and equipment data are compared to a list of targets associated with particular fire scenarios, and the effects on the basic events are propagated through the fault tree logic in the FPRA.

Fire-induced LOOP, also known as consequential LOOP (FIRELOOP), was added to the FPRA as unit-specific LOOP initiators based on events for Bus C, Bus D, and the SAT, leaving the site impacts to be addressed at the mitigating system level. The following illustration describes the fault tree logic for Unit 1 and is representative of the logic for Unit 2:


UNIT LOSS OF OFFSITE POWER EVENTS
ACP_TE_U1
UNIT LOSS OF OFFSITE POWER TO UNIT 1 (PLANT-CENTERED)
%ITE_U1_PC
UNIT LOSS OF OFFSITE POWER TO UNIT 1 (SWITCHYARD-CENTERED)
%ITE_U1_SC
FIRE INDUCED LOSS OF OFF-SITE POWER
FIRELOOP
CONDITIONAL LOOP
#1LOOP_COND
UNIT LOSS OF OFFSITE POWER TO UNIT 1 (GRID-CENTERED)
%ITE_U1_GC
UNIT LOSS OF OFFSITE POWER TO UNIT 1 (WEATHER-CENTERED)
%ITE_U1_WC
FIRE INITIATOR TOP
FIRETOP
FIRE INDUCED LOSS OF OFF-SITE POWER
FIRELOOP01
BNP FIRE COMPARTMENTS
FIRE_COMPARTMENTS
FIRE INITIATOR FLAG
%FIRE
LOSS OF POWER ON 4160V AC BUS 1C
ACP-G41601C-FIRE
FIRE INDUCED LOSS OF OFF-SITE POWER AS INITIAL FAULT FLAG
FIRE-LOOP
LOSS OF POWER ON 4160V AC BUS 1D
ACP-G41601D-FIRE
LOSS OF SUPPLY TO BUS 1C FROM STARTUP TRANSFORMER #1
ACP-G115-FIRE
AC BUS 1C FAILURE (NO POWER)
ACP0BAC-LP-1C
LOSS OF SUPPLY TO BUS 1D FROM STARTUP TRANSFORMER #1
ACP-G015-FIRE
AC BUS 1D FAILURE (NO POWER)
ACP0BAC-LP-1D

NRC Question 22

Enclosure 7, page 53, of the LAR indicates the licensee performed an evaluation to update realistic transient combustibles heat release rate (HRR) for various locations including the DG building. The results of this evaluation indicate that in some areas the use of the 143 Kw HRR (98%) fire for these areas were determined to be realistic and bounding HRR. The submittal further notes that other areas have no impact on the application as either administrative controls limiting transient combustibles, or specific analysis 'will be' performed. Provide confirmation that the indicated analysis for the diesel generator building has been performed and verify if risk significant targets were impacted by the higher HRR transient scenarios.

Response to Question 22

No risk significant target has been impacted by higher HRR transient scenarios in the Diesel Generator Building. As documented in BSEP Change Package-0220, the transient combustible loading in the Diesel Generator Building was evaluated, and a 143 kW HRR (98%) fire was determined to be both reasonably realistic and bounding. Consequently, no specific analysis has been performed to use a higher HRR for transient scenarios in the Diesel Generator Building.

NRC Question 23

Tier 2 evaluations are used to identify high risk equipment that could exist if they are taken out of service along with the equipment involved in the TS change. Enclosure 4, page 22, ranks the risk achievement worth of a range of equipment based on having DG 2 in extended maintenance. The remaining DGs are assumed operational during the maintenance period for one DG. Does this application request extended maintenance for concurrent DG failures. Provide a brief summary of procedures for common cause failure of two or more diesel generators.

Response to Question 23

For planned EDG maintenance, only one EDG is removed from service at any given time. If one or more of the other EDGs becomes inoperable (i.e., unplanned) both units would enter a TS required shutdown if more than one EDG remains inoperable two hours after one or more of the other EDGs became inoperable.

For unplanned EDG maintenance (i.e., one EDG inoperable), TS require that the other EDGs be evaluated for common cause failure (i.e., Required Action D.3.1) or be demonstrated OPERABLE by surveillance test (i.e., Required Action D.3.2) within 24 hours. If two or more EDGs are declared inoperable as determined by common cause evaluation or surveillance test (i.e., unplanned) both units would enter a TS required shutdown.

The BSEP Unit 1 and Unit 2 TS 3.8.1 each require four EDGs OPERABLE in MODES 1, 2 and 3, and two EDGs OPERABLE in MODES 4 and 5. If two or more EDGs are inoperable, TS 3.8.1 Condition D (i.e., one EDG inoperable) and Condition G (i.e., two or more EDGs inoperable) are entered. Condition G requires "Restore all but one EDG to OPERABLE status" within 2 hours. If all but one EDG is restored to OPERABLE status within the 2 hours, the extended Completion Time could be used for the one inoperable EDG. If two or more EDGs remain inoperable at the expiration of the 2 hours, the unit(s) must be shutdown (i.e., in MODE

3 in 12 hours and Mode 4 within 36 hours). Once shutdown (i.e., MODE 4 and 5) TS 3.8.1 requires only two EDGs to be OPERABLE.

OPS-NGGC-1305, Operability Determinations, provides instructions for performing the TS required Common Cause Failure evaluation for an inoperable EDG. The evaluation includes:

1. Determine what component or function has failed:

2. Determine as best possible, the probable failure mechanism for the component or function. Review site operating experience (OE) to determine if this failure has been experienced previously and if so, evaluate the previous common mode failure assessment for validity and review corrective actions taken to ensure that these actions did not contribute to the failure.

3. A review of modifications, work orders, and procedure changes performed since the last successful performance of a surveillance test which verified capability of the function that has failed shall be performed to answer the following questions:

   a. Were any modifications performed on any other EDG(s) that could have caused the failure to occur?

   b. Were any changes performed on any procedure affecting the other EDG(s) that could have caused the failure to occur?

   c. Was any maintenance performed on the other EDG(s) that could have caused the failure to occur?

   d. Was the failure due to any changes to the environmental conditions such as humidity, temperature, FME, or others that could also have affected additional EDG(s)?

   e. Was the failure due to fuel contamination?

   f. Determine if tampering appears to be a possible cause of the failure. If not, state this in the evaluation. If so, notify Supervision.

   g. Make a reasonable attempt to ensure the failure was not due to a manufacturing defect that may be present on the other engines (i.e. a review of 10CFR Part 21 Reports, OE search).

NRC Question 24

Describe how your evaluation includes the possible increase in heat release rate caused by the spread of a fire from the ignition source to other combustibles. Summarize how suppression is included in your evaluation.

Response to Question 24

As described in BNP-PSA-080, fire growth is estimated using guidance in Appendix R of NUREG/CR-6850, Volume 2. All fire scenarios include damage to the ignition source and assume a growth period of 12 minutes, a steady-state period of 8 minutes, and a decay period of 19 minutes. The manual suppression probability is based on the time available compared to the time to damage the first target, which is calculated using the Heskestad's plume temperature correlation and based on the source HRR and the distance to the first target.

If the fire is not suppressed early, the timeline for source HRR growth to the damage threshold of the first cable tray includes half the growth period (i.e., 6 minutes) and, if the first tray has a solid bottom, additional delay time based on HRR (i.e., 30 minutes for 69kW, 15 minutes for 143kW, 10 minutes for 211kW, and 5 minutes for 702kW). In general, the fire growth model assumes cable trays are stacked above the ignition source. The fire propagates upward with each additional unprotected cable tray in the stack requiring additional time (i.e., 4 minutes, 3 minutes, and 2 minutes for the second, third, and fourth, respectively). Beginning with the fifth unprotected cable tray in the stack, one additional minute is added to the timeline to ignite each subsequent unprotected cable tray in the stack. Cable trays wrapped with a rated fire barrier are assumed to prevent damage up to the material rating and stop propagation. Cable trays with solid bottoms will prevent cable damage for ignition sources with HRR 69kW or less. The total fire growth is based on adding the source HRR plus the HRR for each ignited cable tray as a function time, with fire spread in each cable tray offset by the burnout.

For a High Energy Arcing Fault (HEAF), unprotected targets within the Zone of Influence (ZOI) are assumed to be damaged instantly, with no possibility of suppression. Afterwards, a 69kW fire source is assumed to propagate to secondary combustibles, in a manner similar to the previous discussion.

For oil fires, the peak HRR is assumed to occur instantly and is based on the size of the spill, which is based on the amount of oil contained within the ignition source, as well as the size and location of drains and berms. Fire durations are assumed to be bounded by 30 minutes. Propagation to secondary combustible is assumed to occur in a manner similar to the previous discussion.

If the fire is not suppressed early, the fire may grow until a Hot Gas Layer (HGL) forms. Damage is assumed to occur to all identified targets in the Fire Compartment as soon as the HGL temperature is attained.

Suppression is included in the evaluation as a non-suppression probability. As described in BNP-PSA-080, the non-suppression probability is a combination of detection and automatic/manual suppression and is determined consistent with Appendix P of NUREG/CR-6850, Volume 2. The scenario event frequency for a fire that is not suppressed is the product of the ignition frequency and the non-suppression probability.

NRC Question 25

Transient fires should at a minimum be placed in locations within the plant physical analysis units (PAUs) where conditional core damage probability (CCDPs) are highest for that PAU, i.e., at "pinch points." Pinch points include locations of redundant trains or the vicinity of other potentially risk-relevant equipment, including the cabling associated with each. Transient fires should be placed at all appropriate locations in a PAU where they can threaten pinch points. Hot work should be assumed to occur in locations where hot work is a possibility, even if improbable (but not impossible), keeping in mind the same philosophy. Describe how transient and hot work fires are distributed within the PAUs at your plant. In particular, identify the criteria for your plant which determine where an ignition source is placed within the PAUs. Also, if you have areas within a PAU where no transient or hot work fires are located since those areas are considered inaccessible, define the criteria used to define "inaccessible." Note that an inaccessible area is not the same as a location where fire is simply unlikely, even if highly improbable.

Response to Question 25

The placement of transient fires was not limited to locations corresponding to "pinch points." Instead, the location of a postulated transient fire source was based on an evaluation of vulnerable target(s) within an associated ZOI. This evaluation consisted of focused walkdowns, supplemented with the review of drawings as necessary. The transient fire sources were postulated to represent one or more trash bags on the floor, and the ZOIs were determined to represent unprotected, Institute of Electrical and Electronics Engineers (IEEE)-qualified cables as the targets. In general, the zone of influence used to establish the source-target relationship was based on a specific HRR chosen with consideration for plant experience to be appropriate for a particular Fire Compartment. For Fire Compartments that were determined to contain potential targets, the number and footprints of the postulated transient fire sources varied. Based on the grouping of possible targets, a Fire Compartment may have one source encompassing the area of an entire Fire Compartment while a different Fire Compartment may have multiple sources with smaller, non-overlapping footprints.

Hot work comprises both transient fires due to cutting and welding and cable fires due to cutting and welding. Transient fires due to cutting and welding are assumed to involve the same target sets as, and are distributed with, the general transient fires. This assumption was identified as a source of uncertainty in the development of the fire scenario and was evaluated (i.e., BNP-PSA-086) as appropriate because the placement of the general transient fire were based on the selection of vulnerable targets. No target set is defined for cable fires due to cutting and welding, and cable fires caused by cutting and welding are assumed not to spread beyond the original cable tray. This assumption was identified as a source of uncertainty in the development of the fire scenario and was evaluated (i.e., BNP-PSA-086) as appropriate because administrative controls require a fire watch with an extinguisher to be present and because the cable is expected to be self-extinguishing and non-propagating in the absence of a sustained ignition source. Consequently, the impact on CDF is expected to be negligible.

No Fire Compartment was specifically defined as "inaccessible" for the purpose of locating transient and hot work fires. However, earlier in the development of the FPRA, the spent fuel pools were qualitatively screened as being filled with water, and the drywell and torus were screened from quantitative analysis because of the inert atmosphere during normal operations.

NRC Question 26

Discuss the calculation of the frequencies of transient and hot work fires. Characterize your use of the influence factors for maintenance, occupancy, and storage, noting if the rating "3" is the most common, as it is intended to be representative of the "typical" weight for each influence factor. It is expected that the influence factor for each location bin associated with transient or hot work fires will utilize a range of influence factors about the rating "3," including the maximum 10 (or 50 for maintenance) and, if appropriate, even the rating "0." Note that no PAU may have a combined weight of zero unless it is physically inaccessible, administrative controls notwithstanding. In assigning influence factor ratings, those factors for the Control/Auxiliary/Reactor Building are distinct from the turbine building; thus, the influence factor ratings for each location bin are to be viewed according to the bin itself.

Response to Question 26

As described in BNP-PSA-083, the frequencies of transient and hot work fires were calculated for the Fire Compartments, which were quantitatively analyzed, consistent with Section 6.5.7.2

of NUREG/CR-6850, Volume 2, including the use of influence factors for maintenance, occupancy, and storage. The values selected for the influence factors were based on the expert opinion on knowledgeable members of the plant staff who have many years of experience. The Reactor Building Main Steam Isolation Valve (MSIV) Pit on each unit was assigned a combined weight of zero based on being physically inaccessible due to radiation levels during normal operation. In general, the rating "3" was the most common for each location bin; however, maintenance and occupation in the turbine building were notable exceptions with each having the rating "1" as fractionally more common. This skewing of the count toward "below average" was attributed to the turbine building comprising a few relatively large Fire Compartments with unrestricted access and a number of smaller Fire Compartment where access is restricted or prohibited by radiation levels during normal operation.

The resulting transient ignition frequency for a particular Fire Compartment was apportioned to each individual transient ignition source within that Fire Compartment based on the corresponding ratio of the transient ignition source footprint to the floor area for that Fire Compartment.

NRC Question 27

If you have used any influence factors outside of the values identified in Table 6-3 of NUREG/CR-6850, identify the values used, identify the PAUs that use these factors, and justify the assigned factor(s).

Response to Question 27

The influence factors used for quantitative analysis were generally consistent with those identified in Table 6-3 of NUREG/CR-6850, Volume 2. However, no Fire Compartment was judged to warrant a Very High (50) maintenance influence factor. And, the determination of whether entrance to some compartments was possible during plant operations was based on the need, as follows:

Fire Compartment	Description	M	O	S	Justification
FC261	DUCTBANK	1	0	0	The duct bank is a network of underground, concrete cable trenches with junctions that can be accessed through secured manhole covers. Maintenance activities would include periodically removing the covers to check for the accumulation of water or to pull new cables. Otherwise, the manholes are not accessible for occupancy or storage.
FC306	RB1-14, Reactor Building Skimmer Surge Tank Vault	0	1	0	The skimmer surge tank vaults and the RWCU filter pits are closed with concrete shield plugs, for radiation concerns, and are not otherwise accessible for storage. Under certain limitations, the shield plugs could be removed with a hoist or crane to provide access if required to address a leak or other problem. The difference in maintenance influence factors reflects consideration of plant operating experience and
FC356	RB2-14, Reactor Building Skimmer Surge Tank Vault	0	1	0	
FC308	RB1-16, Reactor Building 1A Reactor Water Cleanup (RWCU)	1	1	0	

	Filter Pit				the surge tanks being near atmospheric pressure while the RWCU equipment is near reactor pressure. The surge tank vaults contain no equipment requiring maintenance.
FC358	RB2-16, Reactor Building 2A RWCU Filter Pit	1	1	0	
FC309	RB1-17, Reactor Building 1B RWCU Filter Pit	1	1	0	
FC359	RB2-17, Reactor Building 2B RWCU Filter Pit	1	1	0	

NRC Question 28

Section 10 of NUREG/CR-6850 Supplement 1 states that a sensitivity analysis should be performed when using the fire ignition frequencies in the Supplement instead of the fire ignition frequencies provided in Table 6-1 of NUREG/CR-6850. Provide the sensitivity analysis of the impact on using the Supplement 1 frequencies instead of the Table 6-1 frequencies on CDF, large early release frequency (LERF), ΔCDF, and ΔLERF for all of those bins that are characterized by an alpha that is less than or equal to one. If the sensitivity analysis indicates that the change in risk acceptance guidelines would be exceeded using the values in Table 6-1, please justify not meeting the guidelines.

Response to Question 28

As documented in Engineering Change 89996, a sensitivity analysis was performed, consistent with the guidance in Section 10 of NUREG/CR-6850, Supplement 1, Fire Probabilistic Risk Assessment Methods Enhancements, to determine the impact on CDF, LERF, ΔCDF, and ΔLERF using the Supplement 1 frequencies instead of the NUREG/CR-6850, Volume 2, Table 6-1 frequencies. Except for Bin 9, the sensitivity analysis was performed for the following bins that are characterized by an alpha that is less than or equal to one:

Bin #	Ignition Source	Frequencies	Alpha
1	Batteries	3.26E-04	0.5
4	Main Control Board	8.24E-04	1
9	Air Compressors	4.65E-03	0.5
11	W/C Cable Fires (plant-wide)	9.43E-04	1
13	Dryers	4.20E-04	0.5
15.1	Electrical Cabinets (non-HEAF)	2.36E-02	0.453
22	RPS MG Sets	9.33E-04	0.92
31	W/C Cable Fires (Turbine Building)	4.50E-04	0.5

Bin 9 was not included because Supplement 1 indicates that alpha value to be an apparent error. As a result of this sensitivity analysis, the following fire-related contributors to the identified risk metrics of interest were affected:

FIRE IGNITION FREQUENCY SENSITIVITIES	**Unit 1**		**Unit 2**	
CDF and LERF Results w/o Extended DG AOT	**CDF [/yr]**	**LERF [/yr]**	**CDF [/yr]**	**LERF [/yr]**
Fire[1] (% increase from baseline value in LAR, Enclosure 4, Page 15, Table A4-5)	**3.0E-05** (+78%)	**4.0E-06** (+89%)	**1.9E-05** (+22%)	**1.3E-06** (+42%)
Fire-induced MCRA[2] (% increase from baseline value in LAR, Enclosure 4, Page 15, Section 4.5.2, last paragraph under Fire Risk Insights)	**2.1E-05** (+114%)	**2.1E-06** (+114%)	**2.1E-05** (+114%)	**2.1E-06** (+114%)
Total[3] (% increase from baseline value in LAR, Enclosure 1, Page 29, Section 4.4.7)	**6.6E-05** (+60%)	**6.7E-06** (+81%)	**5.5E-05** (+37%)	**4.1E-06** (+60%)
ΔCDF and ΔLERF Results for Extended DG AOT	**ΔCDF [/yr]**	**ΔLERF [/yr]**	**ΔCDF [/yr]**	**ΔLERF [/yr]**
Fire[1] (% increase from baseline value in LAR, Enclosure 4, Page 15, Table A4-5)	**3.9E-07** (+38%)	**1.2E-09** (+20%)	**3.5E-07** (+30%)	**3.5E-09** (+40%)
Fire-induced MCRA[2] (% increase from baseline value in LAR, Enclosure 4, Page 15, Section 4.5.2, last paragraph under Fire Risk Insights)	**0** (0%)	**0** (0%)	**0** (0%)	**0** (0%)
Total[3] (% increase from baseline value in LAR, Enclosure 1, Page 29, Section 4.4.7)	**9.6E-07** (+13%)	**5.0E-09** (+4%)	**9.1E-07** (+10%)	**7.2E-09** (+16%)

[1] Fire results include Main Control Room (MCR) abandonment for loss of control but not for environmental reasons.
[2] Values are associated with control room abandonment due to environmental reasons.
[3] Also includes contributions from External Hazards and other Internal Hazards, in addition to Internal Fire.
[4] Percent increase is based on significant digits not shown, minor differences below significant digits shown are considered negligible.

With respect to Regulatory Guide 1.174, An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Section 2.4 Acceptance Guidelines, the total CDF and total ΔCDF correspond to Region III in Figure 4, Acceptance Guidelines for Core Damage Frequency, and the total LERF and total ΔLERF correspond to Region III in Figure 5, Acceptance Guidelines for Large Early Release Frequency.

NRC Question 29

Please describe how CDF and LERF are estimated in main control room (MCR) abandonment scenarios. Do any fires outside of the MCR cause MCR abandonment because of loss of control and/or loss of control room habitability? Are "screening" values for post MCR abandonment used (e.g., conditional core damage probability of failure to successfully switch control to the Primary Control Station and achieve safe shutdown of 0.1) or have detailed human error analyses been completed for this activity. Please justify any screening value used.

Response to Question 29

As described in Section 4.5.5 and Attachment 10 of BNP-PSA-084, a detailed human reliability analysis was performed to determine the failure probability for the operator actions to prevent core damage using the Alternate Safe Shutdown procedures, in the event that the MCR becomes uninhabitable and is abandoned due to fire or smoke. As described in Attachment 15 of BNP-PSA-080, no fire outside the MCR contributes to MCR abandonment for habitability. For loss of control, the operator actions following MCR abandonment are also credited for fires in both the MCR and the cable spreading rooms which is directly below, as described in Attachment 6 of BNP-PSA-092. LERF was estimated as an order of magnitude lower than CDF, but no "screening" value was used.

NRC Question 30

It was recently stated at the industry fire forum that the Phenomena Identification and Ranking Table Panel being conducted for the circuit failure tests from the DESIREE-FIRE and CAROL-FIRE tests may be eliminating the credit for Control Power Transformers (CPTs) (about a factor 2 reduction) currently allowed by Tables 10-1 and 10-3 of NUREG/CR-6850, Vol. 2, as being invalid when estimating circuit failure probabilities. Provide a sensitivity analysis that removes this CPT credit from the PRA and provide new results that show the impact of this potential change on CDF, LERF, ΔCDF, and ΔLERF. If the sensitivity analysis indicates that the change in risk acceptance guidelines would be exceeded after eliminating CPT credit, please justify not meeting the guidelines.

Response to Question 30

As documented in Engineering Change 89996, a sensitivity analysis was performed to determine the impact on CDF, LERF, ΔCDF, and ΔLERF using the failure mode probability estimates in NUREG/CR-6850, EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities, Volume 2 Detailed Methodology, Tables 10-2 and 10-4 instead of those in Tables 10-1 and 10-3, respectively. The following hot short probabilities were affected:

Raceway Type	Description of Hot Short Failure Mode	Best Estimate Failure Probability NUREG/CR-6850			
		Table 10-1	Table 10-2	Table 10-3	Table 10-4
Tray	Multi-conductor intra-cable	0.30	0.60	0.30	0.60
Tray	Multi-conductor →Multi-conductor inter-cable	0.03	0.06	0.03	0.06

As a result of this sensitivity analysis, the following fire-related contributors to the identified risk metrics of interest were affected:

CPT CABLE FAILURE SENSITIVITIES	Unit 1		Unit 2	
CDF and LERF Results w/o Extended DG AOT	**CDF [/yr]**	**LERF [/yr]**	**CDF [/yr]**	**LERF [/yr]**
Fire[1] (% increase from baseline value in LAR, Enclosure 4, Page 15, Table A4-5)	**1.7E-05** (+2%)	**2.1E-06** (+1%)	**1.6E-05** (+2%)	**9.6E-07** (+3%)
Total[2] (% increase from baseline value in LAR, Enclosure 1, Page 29, Section 4.4.7)	**4.1E-05** (+1%)	**3.7E-06** (+1%)	**4.0E-05** (+1%)	**2.6E-06** (+1%)
ΔCDF and ΔLERF Results for Extended DG AOT	**ΔCDF [/yr]**	**ΔLERF [/yr]**	**ΔCDF [/yr]**	**ΔLERF [/yr]**
Fire[1] (% increase from baseline value in LAR, Enclosure 4, Page 15, Table A4-5)	**2.8E-07** (+0%)	**1.1E-09** (+10%)	**2.6E-07** (-5%)[3]	**2.5E-09** (+0%)
Total[2] (% increase from baseline value in LAR, Enclosure 1, Page 29, Section 4.4.7)	**8.5E-07** (+0%)	**4.9E-09** (+2%)	**8.2E-07** (-1%)[3]	**6.2E-09** (+0%)

[1] Fire results include Main Control Room (MCR) abandonment for loss of control but not for environmental reasons.
[2] Also includes contributions from External Hazards and other Internal Hazards, in addition to Internal Fire.
[3] Slight negative variances are attributed to limitation of the quantification software involving min-cut upper-bound.
[4] Percent increase is based on significant digits not shown, minor differences below significant digits shown are considered negligible.

With respect to Regulatory Guide 1.174, An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Section 2.4 Acceptance Guidelines, the total CDF and total ΔCDF correspond to Region III in Figure 4, Acceptance Guidelines for Core Damage Frequency, and the total LERF and total ΔLERF correspond to Region III in Figure 5, Acceptance Guidelines for Large Early Release Frequency.

NRC Question 31

Did the peer reviews for both the internal events and fire PRAs consider the clarifications and qualifications from Regulatory Guide (RG) 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," March 2009 (ADAMS Accession No. ML090410014) to the ASME/AMS PRA Standard? If not, provide a self-assessment of the PRA model for the RG 1.200 clarifications and qualifications and indicate how any identified gaps were dispositioned.

Response to Question 31

The clarifications and qualifications from Regulatory Guide 1.200, Revision 2, to the ASME/ANS PRA Standard were considered during the peer reviews for both the Internal Events PRA and the Fire PRA.

NRC Question 32

Sufficient level of information on the fire PRA will be needed for performing the review of the fire PRA for the application. This includes identification and technical justification of any unreviewed analysis methods (UAMs), as well as a description of other method differences from NUREG/CR-6850 (as supplemented) or the National Fire Protection Association Standard 805, "Performance Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," (NFPA-805) frequently asked question guidance, and their significance for the application. If a position on a previous UAM has been established on a method by the NRC, confirm that the accepted version of the UAM is used per the NRC position and, if not, then provide a revised analysis and results using an accepted approach.

Response to Question 32

The FPRA Peer Review team identified, as F&O 4-1, the use of a split fraction for "Open"/"Closed" MCCs to be an Unreviewed Analysis Method. In particular, the Finding noted that the BSEP FPRA calculates using 1) a severity factor 0.1, where 90% of the fires are contained within the MCC, and 2) HRR severity factors are treated independently similar to other cabinets.

Contrary to the Finding by the Peer Review team, BSEP does not consider this to be an unreviewed analysis method because this treatment is described in a sensitivity study in Section 3.4.7 and Table 3.4-6 of the Safety Evaluation for the Shearon Harris Nuclear Plant license amendment regarding NFPA 805, dated June 28, 2010 (ADAMS Accession Number ML 101750602, ML101750604). In particular, the assumption that a small percentage of fires will cause damage outside the MCC cabinet was identified with an assessment of the physical design and associated fire modeling as a reasonable basis for considering the MCCs as closed cabinets.

Following the guidance provided by NUREG/CR-6850, it has been determined that some MCCs can be treated as "closed" cabinets. As such, there is no impact to external targets. Based on challenges that there is potential for an arc fault to have enough energy to open the cabinet, even though the documentation specifically excludes the need to apply HEAFs to MCCs, it is assumed that one out of ten MCC fires may result in an "open" cabinet configuration.

This is not applied to the HRR as a severity factor, but as a split fraction on the likelihood on the cabinet to be "closed".

To support this treatment of "closed" MCCs at BNP, a walkdown of the construction and closure of the MCCs was performed. For those MCCs subjected to this treatment, the results indicated that the configuration and type of MCCs at BNP are similar to those at HNP.