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RS-18-102

10 CFR 50.90

August 10, 2018

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

Byron Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (EGC) requests amendments to Renewed Facility Operating License Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2. Specifically, the proposed changes add License Conditions to Appendix C, and extend the Completion Time for Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2, from 72 hours to 79 days on a one-time, temporary basis based on a risk-informed approach.

This licensing action will serve as a contingency to allow the restoration of an inoperable qualified circuit between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System resulting from an unanticipated failure of Unit 2 System Auxiliary Transformer (SAT) 242-1.

The need for this LAR is due to the fact that Byron Station, Unit 2 SAT 242-2 recently experienced a catastrophic failure and is currently unavailable to support the onsite Class 1E AC distribution systems of either Byron Station unit. In this configuration (i.e., SAT 242-1 serving as the sole source of power for one of the two required qualified circuits for both units), the failure of SAT 242-1, would result in the loss of one the two qualified circuits per bus between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System as defined in LCO 3.8.1.a, and entry into LCO 3.8.1 Condition A for Units 1 and 2.

A001
NRR

This request is subdivided as follows:

Attachment 1 provides an evaluation of the proposed changes.

Attachment 2 includes the marked-up Unit 1 Renewed Facility Operating License, Appendix C page with the proposed changes indicated.

Attachment 3 includes the marked-up Unit 2 Renewed Facility Operating License, Appendix C page with the proposed changes indicated.

Attachment 4 includes the marked-up TS page with the proposed changes indicated.

Attachment 5 includes the revised (clean copy) of the TS page.

Attachment 6 provides a summary of the regulatory commitments contained in this letter.

Attachment 7 provides the supporting risk-informed evaluation of the requested change including an evaluation of the technical adequacy of the PRA in accordance with RG 1.200.

Attachment 8 is the Unit 2 System Auxiliary Transformer 242-2 Repair and Testing Schedule.

Attachment 9 is a copy of the most recent Byron Station Nuclear Plant Interface Requirements.

Attachment 10 is a copy of Byron Station UFSAR Table 8.3-5, "Loading on 4160-Volt Engineered Safety Features (ESF) Buses"

The proposed changes have been reviewed by the Byron Station Plant Operations Review Committee in accordance with the requirements of the EGC Quality Assurance Program.

EGC requests approval of the proposed license amendment request by August 10, 2019. Once approved, the amendments will be implemented immediately.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), EGC is notifying the State of Illinois of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

There are new regulatory commitments contained within this letter as discussed in Attachment 6. Should you have any questions concerning this letter, please contact Mr. Mitchel A. Mathews at (630) 657-2819.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 10th day of August 2018.

Respectfully,

David M. Gullott
Manager – Licensing
Exelon Generation Company, LLC

Attachments:

1. Evaluation of Proposed Changes
2. Proposed Unit 1 Renewed Facility Operating License, Appendix C Changes (Markup)
3. Proposed Unit 2 Renewed Facility Operating License, Appendix C Changes (Markup)
4. Proposed Technical Specifications Page Changes (Markups)
5. Revised (Clean) Technical Specifications Page
6. Summary of Compensatory Measures and Regulatory Commitments
7. BY-LAR-012, "Risk Assessment Input for the Byron One-Time Technical Specification Change for Condition 3.8.1.A Completion Time from 72 Hours to 79 days for Units 1 and 2," dated August 9, 2018
8. Unit 2 System Auxiliary Transformer 242-2 Repair and Testing Schedule
9. Byron Station Nuclear Plant Interface Requirements, Revision 5
10. Byron Station UFSAR Table 8.3-5, "Loading on 4160-Volt Engineered Safety Features (ESF) Buses"

cc: NRC Regional Administrator, Region III
NRC Senior Resident Inspector, Byron Station
Illinois Emergency Management Agency – Division of Nuclear Safety

SUBJECT: License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

1.0 SUMMARY DESCRIPTION

This evaluation supports a request in accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," to amend Renewed Facility Operating License Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2.

Specifically, the purpose of the Byron Station license amendment request (LAR) is to seek NRC review and approval of a risk-informed approach to extending the Technical Specifications (TSs) Completion Time (CT) for TS 3.8.1, "AC Sources-Operating," Condition A, "One or more buses with required qualified circuit inoperable," Required Action A.2, "Restore required qualified circuit(s) to OPERABLE status," from 72 hours to 79 days.

This one-time change to TS 3.8.1 and associated Renewed Facility Operating Licensing (FOL) Conditions will serve as a contingency to allow the restoration of an inoperable qualified circuit between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System resulting from the failure of Unit 2 System Auxiliary Transformer (SAT) 242-1.

The need for this LAR is due to the fact that Byron Station, Unit 2 SAT 242-2 recently experienced a catastrophic failure and is currently unavailable to support the onsite Class 1E AC distribution systems of either Byron Station unit. In this configuration (i.e., SAT 242-1 serving as the sole source of power for one of the two required qualified circuits for both units), the failure of SAT 242-1 will result in the loss of one the two qualified circuits as defined in Limiting Condition for Operation (LCO) 3.8.1.a, and entry into TS 3.8.1 Condition A for Units 1 and 2.

Byron Station does not currently have a spare SAT, and the replacement SAT for SAT 242-2 is not scheduled to arrive onsite until late December 2018. If SAT 242-1 were to fail, both Byron Station Units would be in TS 3.8.1, Condition A, which currently has a 72-hour CT consistent with Regulatory Guide 1.93, "Availability of Electric Power Sources," Regulatory Position 1. Therefore, the contingency would be necessary to either effect repairs to SAT 242-1, or to install the SAT 242-2 replacement transformer, if possible. The utilization of the extended Required Action A.2 CT would only be allowed if the station can complete the repairs and restore the required qualified circuit within the time allowed by the Probabilistic Risk Analysis (PRA).

2.0 DETAILED DESCRIPTION

2.1 Proposed Change to the Operating Licenses and Technical Specifications

TS LCO 3.8.1 currently requires that two qualified circuits per bus between the offsite transmission network and the onsite Class 1E AC electrical power distribution system must be operable in Modes 1, 2, 3 and 4 and that two diesel generators (DGs) capable of supplying the onsite Class 1E AC electrical power distribution system be Operable for each Byron Station unit. Condition A allows one qualified circuit for one or more buses to be inoperable for up to 72 hours. An extension of the CT to 79 days is needed as a contingency should the need to repair or replace an unanticipated inoperable qualified circuit arise as a result of the failure of system auxiliary transformer (SAT) 242-1. This CT extension for one inoperable from 72 hours to 79 days is needed to allow for the repair or replacement of a Unit 2 SAT. The extension of the CT to 79 days is supported by the risk assessment summarized below in Section 4.0 and detailed in Attachment 9. This evolution is not a typical maintenance activity that can be performed within the existing 72-hour CT and current planning estimates and maintenance history have shown that SATs cannot be replaced within the current CT.

EGC proposes to add the following new License Conditions to the Byron Station, Units 1 and 2 Renewed Facility Operating Licenses (FOLs) in Appendix C for each license and as shown in Figure 1 below:

Proposed License Conditions

Unit 1

1. The Unit 1 diesel generators (DGs) (i.e., 1DG01KA and 1DG01KB) will be protected in accordance with the Exelon Generation Company, LLC (EGC) Procedure OP-AA-108-117, "Protected Equipment Program," for the duration of the temporary extended Technical Specification (TS) 3.8.1, "AC Sources-Operating," Condition A, Required Action A.2, Completion Time associated with the failure of Unit 2, System Auxiliary Transformer (SAT) 242-1, to aid in avoiding inadvertent impacts from walkdowns, inspections, maintenance, and potential for transient combustible fires.

   All TS Surveillance Requirements (SRs) will continue to be performed as required to ensure DG Operability. If either Unit 1 DG becomes inoperable, for reasons other than the performance of TS SRs, EGC shall comply with the appropriate Required Actions for the associated Conditions as defined in the TSs.

2. If EGC determines prior to expiration of the extended TS Completion Time associated with the failure of SAT 242-1, a common failure mode for any remaining qualified offsite circuits exists, then EGC shall evaluate the Operability of the remaining offsite sources and comply with the appropriate TS Conditions and associated Required Actions.

Unit 2

1. The following equipment will be protected in accordance with the Exelon Generation Company, LLC (EGC) Procedure OP-AA-108-117, "Protected Equipment Program," for the duration of the temporary extended Technical Specification (TS) 3.8.1, "AC Sources-Operating," Condition A, Required Action A.2, Completion Time associated with the failure of Unit 2, System Auxiliary Transformer (SAT) 242-1, to aid in avoiding inadvertent impacts from walkdowns, inspections, maintenance, and potential for transient combustible fires:

   a. Unit 2 Diesel Driven Auxiliary Feedwater Pump (2AF01PB)
   b. All Unit 2 Diesel Generators (i.e., 2DG01KA and 2DG01KB)

   All TS Surveillance Requirements (SRs) will continue to be performed as required to ensure equipment Operability. If any of this equipment becomes inoperable, for reasons other than the performance of TS SRs, EGC shall comply with the appropriate Required Actions for the associated Conditions as defined in the TSs.

2. If EGC determines prior to expiration of the extended TS Completion Time associated with the failure of SAT 242-1, a common failure mode for any remaining qualified offsite circuits exists, then EGC shall evaluate the Operability of the remaining offsite sources and comply with the appropriate TS Conditions and associated Required Actions.

APPENDIX C

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-37

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
127	The safety limit equation specified in TS 2.1.1.3 regarding fuel centerline melt temperature (i.e., less than 5080 °F, decreasing by 58 °F per 10,000 MWD/MTU burnup as described in WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995) is valid for uranium oxide fuel without the presence of poisons mixed homogeneously into the fuel pellets. If fuel pellets incorporating homogeneous poisons are used, the topical report documenting the fuel centerline melt temperature basis must be reviewed and approved by the NRC and referenced in this license condition. TS 2.1.1.3 must be modified to also include the fuel centerline melt temperature limit for the fuel with homogeneous poison.	With implementation of the amendment

Insert

Figure 1: Proposed Change to Byron Station, Units 1 and 2 Renewed Facility Operating License, Appendix C (Unit 1 Example)

These proposed new License Conditions will allow for the restoration of a qualified offsite circuit for Byron Station, Units 1 and 2 following an unanticipated failure of Unit 2 SAT 242-1.

Marked-up versions of the Unit 1 and 2 Renewed FOL Appendix C pages are provided in Attachments 2 and 3, respectively.

The specific TS changes shown in Figure 2 below are proposed to extend the completion time on a one-time, risk-informed basis for the restoration of qualified circuits to an OPERABLE status for Byron Station, Units 1 and 2 following an unanticipated failure of SAT 242-1. If the circuit cannot feasibly be restored to OPERABLE within this Completion Time, Units 1 and 2 shall be placed in MODE 3 (i.e., Hot Standby) in 6 hours and MODE 5 (i.e., Cold Shutdown) in 36 hours in accordance with the Required Actions associated with TS 3.8.1, Condition G.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more buses with one required qualified circuit inoperable. --------NOTE---------- For the failure of Unit 2 System Auxiliary Transformer 242-1, restore the required qualified circuit to OPERABLE status within 79 days. --------------------------	A.1	Perform SR 3.8.1.1 for the required OPERABLE qualified circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours <u>AND</u> 17 days from discovery of failure to meet LCO

(continued)

Figure 2: Proposed TS Changes for One-Time Restoration of Required Qualified Circuit Following Unanticipated Failure of SAT 242-1

A marked-up TSs page is provided in Attachment 4 and a revised TS page (clean copy) is provided in Attachment 5.

2.2 <u>Need for the Proposed Change</u>

On July 6, 2018, Byron Station, Unit 2 SAT 242-2 suddenly failed resulting in a sudden pressure trip and isolation of SATs 242-1 and 242-2 from the Byron Station switchyard. The physical damage was readily apparent to plant operators when responding to the event, as oil was observed leaking from cracks in the high voltage bushings on the transformer.

Physical damage resulted from an internal short on transformer windings, rendering SAT 242-2 inoperable and unable to be repaired utilizing available EGC resources.

Following the failure of SAT 242-2, Byron Station, Unit 2 electric power system was aligned in a configuration where SAT 242-1 is serving as the sole source of power for one of the two required qualified circuits for both units. Therefore, a failure of the remaining Unit 2 SAT, 242-1, would amount to a loss of one the two required qualified circuits for each unit as defined in LCO 3.8.1.a, and require entry into TS 3.8.1, Condition A for Units 1 and 2.

Byron Station does not currently have a spare SAT, and the replacement SAT for SAT 242-2 is being manufactured and is not scheduled to arrive onsite until late December 2018. If SAT 242-1 were to fail, both Byron Station Units would be in TS 3.8.1, Condition A, and the associated Required Action A.2 currently has a 72-hour Completion Time for restoration of a required qualified offsite circuit consistent with Regulatory Guide 1.93, "Availability of Electric Power Sources," Regulatory Position 1. Therefore, a one-time change is requested as a contingency for the completion of repairs to SAT 242-1, or the installation of SAT 242-2 replacement transformer, if available. The utilization of the extended Required Action A.2 Completion Time would only be allowed if the station can complete the repairs and restore the required qualified circuit to an Operable status within the time allowed by the PRA analysis.

Current plans to replace SAT 242-2 will exceed the TS Required Action Completion Time of 72 hours. Attachment 8 of this request provides a high-level schedule of activities planned to restore SAT 242-2 and perform startup and post-maintenance testing. EGC has determined the preliminary cause of the failure of SAT 242-2 does not represent a common mode failure potential for the remaining SATs, and has evaluated the operational risk and is requesting an LAR to extend the Completion Time to allow completion of repair and testing, if an emergent failure of SAT 242-1 were to occur.

EGC requests the approval of the LAR by August 10, 2019. EGC will implement the TS amendment immediately following NRC approval. Absent approval, if SAT 242-1 were to fail, and EGC was unable to effect repairs with the 72-hour Completion Time of TS 3.8.1, Required Action A.2, Byron Station, Units 1 and 2 would be required to shut down in accordance with LCO 3.8.1, Condition G.

2.3 Basis for Duration of Completion Time Extension

SAT 242-2 sustained extensive damage as a result of the recent failure. The repairs require the manufacture of a replacement transformer. This process typically takes on the order of 55 weeks to complete; however, EGC has negotiated the manufacture of the SAT 242-2 replacement on an expedited basis and is currently anticipating that the replacement transformer will arrive onsite in December 2018. The requested completion time extension will allow for the repair and testing of SAT 242-1, or the replacement of SAT 242-2, if possible within the proposed Completion Time.

The activities associated with the replacement of SAT 242-2 are described in Attachment 8, which reflects a schedule that restores SAT 242-2 to an Operable status by February 2019. The options for the repair of an unanticipated failure of SAT 242-1 are currently unknown; therefore, it is not feasible to predict what they may entail. In any case, EGC will restore a required qualified circuit to operable status as soon as practicable.

3.0 BACKGROUND

3.1 Current Plant Design

Electric energy generated at Byron Station is transformed from generator voltage to a nominal 345 kV transmission system voltage by the main power transformers. The main power

transformers are connected via intermediate transmission towers to the station's 345 kV transmission terminal. A one line diagram of the 345 kilovolt (kV) bus arrangement is shown on Figure 3 below. The 345 kV overhead lines exit the station transmission terminal on three separate rights of way.
Figure 5 below shows the transmission line routing on the site property, and Figure 3 below indicates the general routes and lengths of transmission lines from the station to major substations on the Commonwealth Edison grid. No other transmission lines cross over these lines and as the lines enter the station via three separate rights of way a structural failure in any one line will not result in the loss of the transmission lines entering the site via the other two rights of way.

The preferred power system is considered as having three major sections, each of which must provide two physically separate and electrically independent circuit paths between the onsite power system and the transmission network (the transmission network excludes the station switchyard). The three sections are:

1. The transmission lines entering the station switchyard from the transmission network.
2. The station switchyard. (A common switchyard is allowed by GDC 17).
3. The overhead transmission lines, SATs, buses between the switchyard, and the onsite power system.

The station's 345 kV switchyard ring buses are continuously energized and serve as the preferred power source for the station's safety loads. The two power circuits from the 345 kV switchyard ring buses to each unit's Class 1E distribution system enter through two physically separate rights of way with independent transmission line structures. These lines enter the switchyard from the opposite sides to the lines leaving the switchyard and terminate at transformers located on the opposite sides of the reactor buildings. There are no other lines crossing these preferred power lines. A single event will not simultaneously affect both circuits in such a way that neither can be returned to service within the time limit to exceed any design limits. The system auxiliary transformers step the 345 kV system voltage down to the station 4160 volt and 6900 volt power systems. Each pair of system auxiliary transformers is sized to provide the total auxiliary power for one unit plus the ESF auxiliary power for the other unit.

ATTACHMENT 1
Evaluation of Proposed Changes

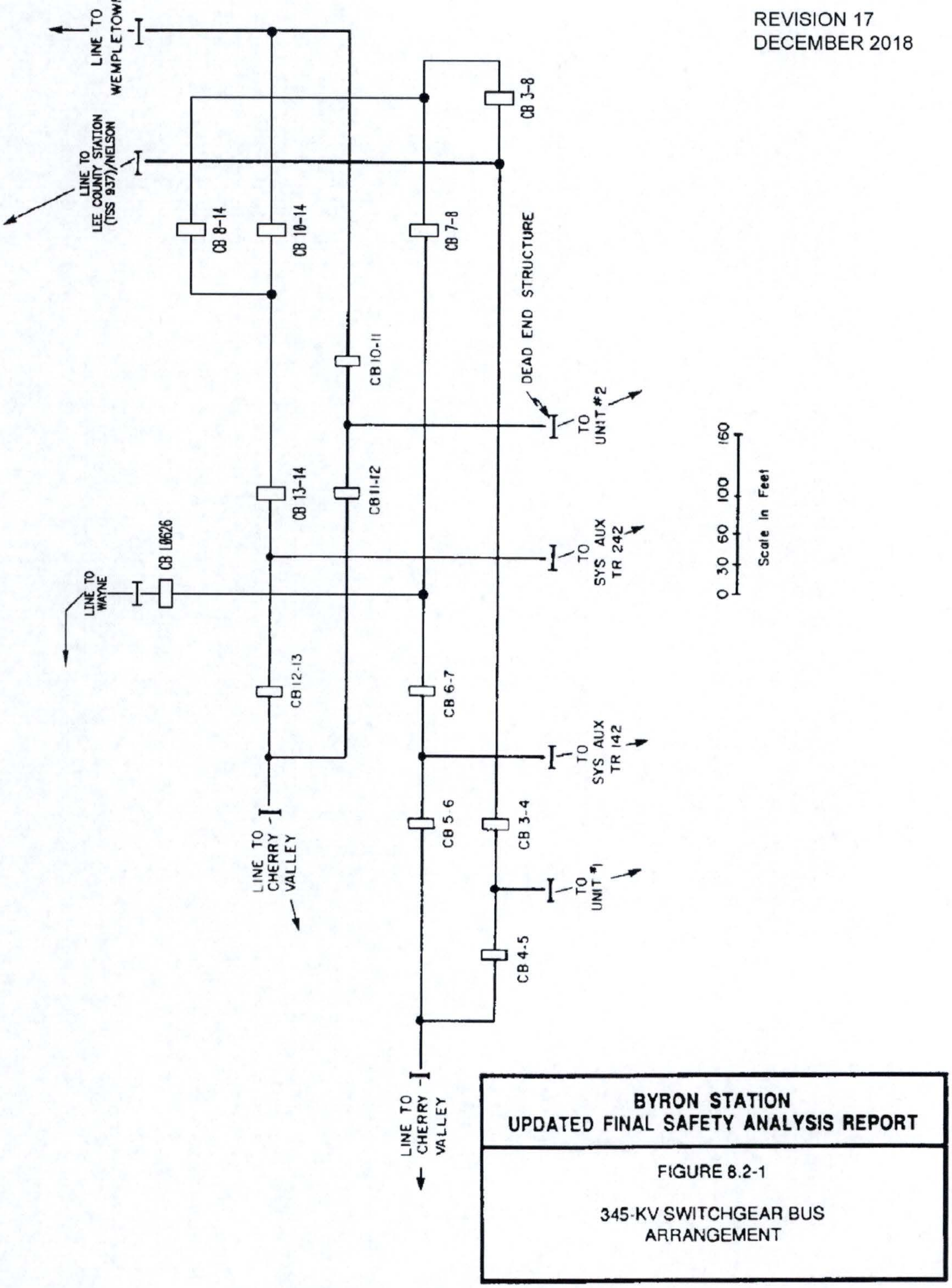

Figure 3: Byron Station Updated Final Safety Analysis Report (UFSAR) Figure 8.2-1

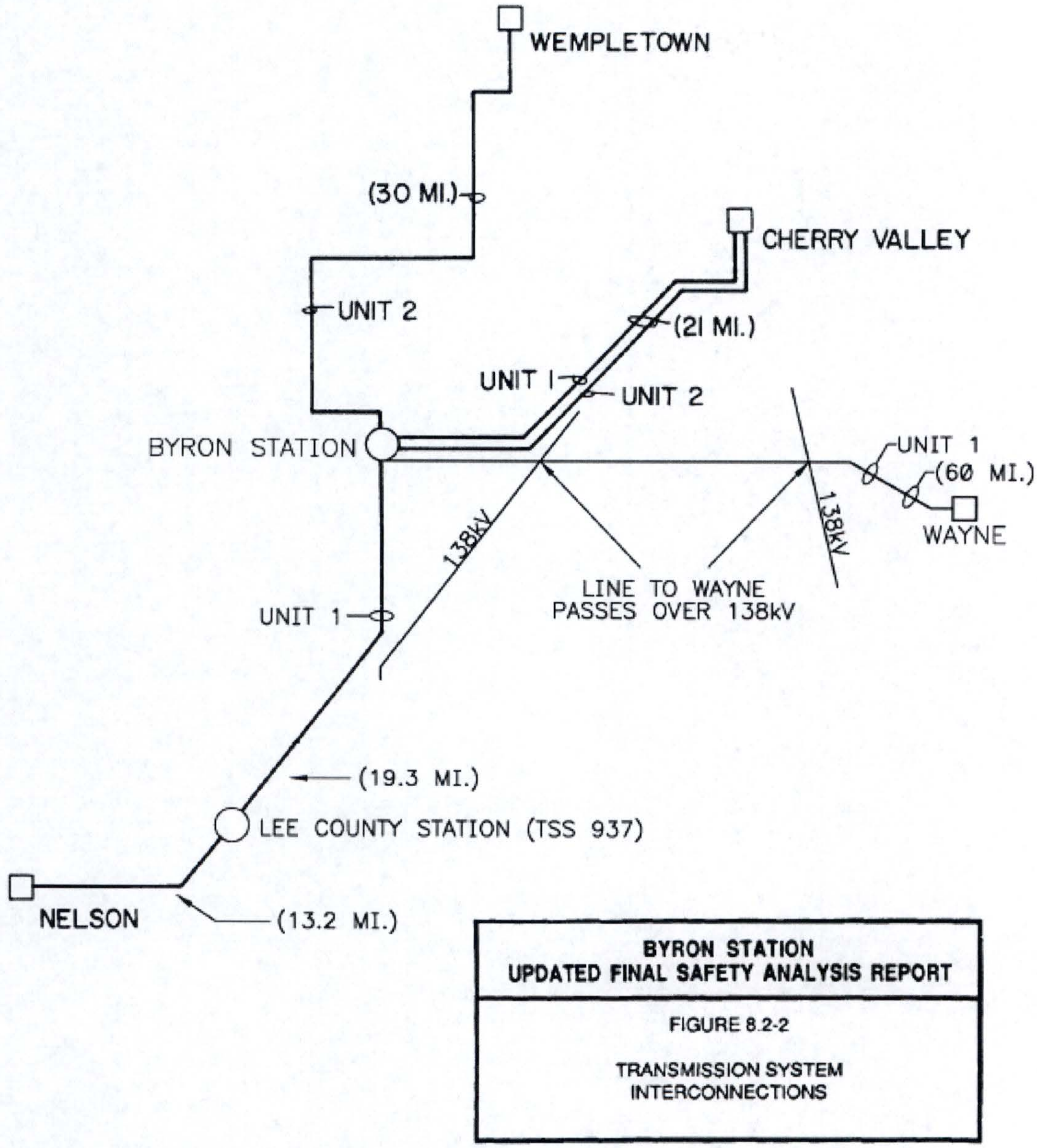

Figure 4: Byron Station UFSAR Figure 8.2-2

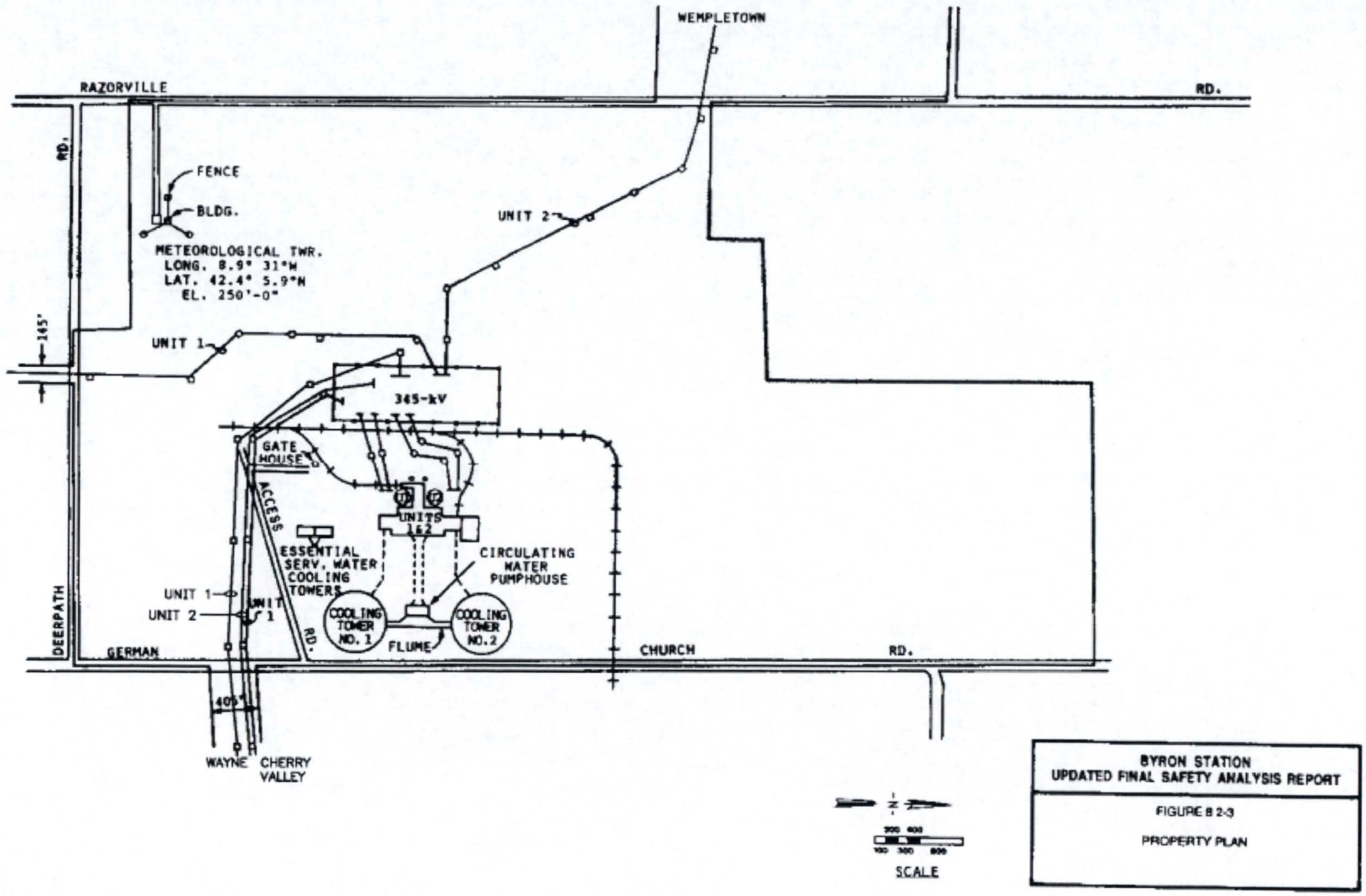

Figure 5: Byron Station UFSAR Figure 8.2-3

The transmission terminal 345 kV circuit breakers are configured to afford optimum protection for the bus in the event of a transmission line, generator, or bus fault. Relay tripping of the breakers over a microwave communication system is used for line protection for line L15501 (only). Relay tripping of the breakers over a direct fiber connection to the switchyard dual fiber ring is used for line protection for lines L0621, L0622, L0624, L0626 and L0627. Should a breaker fail to operate or primary relaying fail to trip a breaker, local breaker backup (LBB) will operate the adjacent breaker. The operation of the adjacent breaker still provides maximum reliability of power supplied to the bus as it will only isolate an additional bus section. For instance, the ring bus is configured so that a generator trip from the backup protection system will not jeopardize the availability of the system auxiliary transformer or one of the two transmission feeds to the ring bus for the unit. Control power for operation of the 345 kV breakers is provided by two 125 volt batteries located in the switchyard. The 345 kV switchyard relay house houses the 125 volt batteries and the protective relays.

The only remote source of fire, explosion, or missiles in the area of the transmission terminal would be the circuit breakers. The worst possible failure of any circuit breaker and the microwave tower will not result in the total loss of offsite power.

Further discussion concerning the relationship between the station's offsite power system and its onsite auxiliary power system is described below.

<u>Offsite Power Sources (SATs)</u>

There is a set of two normally connected system auxiliary transformers for each unit. Each one of the system auxiliary transformers normally supplies one division. The set of two SATs is sized to provide the required power of the unit under startup, full load, safe shutdown, and DBA load conditions.

From the switchyard, two electrically and physically separated lines (i.e., independent transmission circuits) provide AC power through their associated SAT banks (i.e., SATs 142-1 and 142-2 from one line, and SATs 242-1 and 242-2 from the second line), to the 4.16 kV ESF buses. Normally, SATs 142-1 and 142-2 feed Unit 1 4.16 kV ESF buses, and SATs 242-1 and 242-2 feed Unit 2 4.16 kV ESF buses. Additionally, each 4.16 kV ESF bus has a reserve feed via its associated crosstie to an opposite unit 4.16 kV ESF bus. Each unit is required to have qualified normal and reserve circuits to each 4.16 kV bus (detailed in the LCO Bases for this Specification).

In the event of a failure of one system auxiliary transformer, removable links can be relocated to connect the other system auxiliary transformer to supply both divisions. This provides flexibility in the auxiliary power system. Each set of system auxiliary transformers is capable of supplying the DBA loads of both divisions of one unit and the safe shutdown loads of both divisions of the other unit simultaneously. DBA and safe shutdown loads are shown in UFSAR Table 8.3-5. A copy of Table 8.3-5 has been included as Attachment 10.

One system auxiliary transformer is not capable of supplying the DBA loads and all the nonsafety loads of one unit simultaneously. Prior to single SAT operation, bus loads are evaluated to verify that DBA loads and the nonsafety loads are within the capability of the system auxiliary transformer. Single SAT operation on Unit 2 has been analyzed in Calculation

BYR96-229 to provide operational loading and line-up restrictions for operating procedure BOP AP-86. This analysis confirms the unit is able to operate continuously on a single SAT and meet all of the DBA loads.

The 4160 V ESF buses 141 (241) and 142 (242) will not be fed from the same SAT (parallel operation) except when one of the unit's SATs is unavailable, and the removable links are manually relocated from the transformer secondary to the bus duct cross tie.

The preferred configuration for Unit 1 (Unit 2) under normal operating conditions is:

a. The 4160 volt ESF bus 141 (241) fed from the 345 kV utility grid through SAT 142-1 (242-1) and circuit breaker 1412 (2412). Unit 2 cross tie breaker 1414 (2414) and diesel generator feed breaker 1413 (2413) are open.

b. The 4160 volt ESF bus 142 (242) fed from the 345 kV utility grid through SAT 142-2 (242-2) and circuit breaker 1422 (2422). Unit 1 cross tie breaker 1424(2424) and diesel generator feed breaker 1423 (2423) are open.

For all normal or abnormal conditions, power is supplied to the 4160-volt ESF buses either through the unit's SAT, by automatic transfer to the diesel generator on loss of the SAT, or by manual transfer to the second offsite power source (i.e., through the opposite unit's SATs).

<u>Analysis</u>

The probability of losing the offsite electric power supply has been minimized by the design of the Commonwealth Edison transmission system and the Exelon Generation Company system. Increased reliability is provided through interconnections to neighboring systems. At the beginning of 1985, the Commonwealth Edison transmission system consisted, in part, of ninety-two 345 kV lines totaling 2335 miles, and three 765 kV lines totaling 90 miles. The transmission system is interconnected with neighboring electric utilities at 28 points, nine at 138 kV, 18 at 345 kV, and one at 765 kV.

The interconnections between Byron Station and the Commonwealth Edison grid and the MAIN, ECAR, and MAPP grids are shown in Figure 4.

Commonwealth Edison is a member of PJM. One of the functions of PJM is to ensure that the transmission system is reliable and adequate. A copy of the most recent Byron Station Nuclear Plant Interface Requirements, including voltage operating limits, has been included as Attachment 9.

<u>Emergency Onsite Power Sources (Diesel Generators)</u>

The onsite (emergency) alternating current (AC) power system for each unit consists of two diesel generators, one for each ESF division. The diesel generators provide an independent emergency source of power in the event of a complete loss of offsite power. The diesel generator supplies all of the electrical loads which are required for reactor safe shutdown either with or without a loss of coolant accident (LOCA).

Each diesel generator unit consists of a diesel engine, an electrical generator and fuel oil, lubricating oil, combustion air, cooling water and diesel generator room ventilation support systems which must all be functional when a diesel start signal is received. Short term unavailability of the diesel-generator room ventilation fans and dampers is bounded by the High Energy Line Break (HELB) analysis. The diesel engine, a Cooper Bessemer KSV-20-T diesel, is rated at 7680 hp at 600 rpm when using a turbocharger. The twenty cylinder engine has a 13.5 inch bore with a 16.5 inch stroke and is arranged in a "v" bank configuration with ten cylinders assigned to each bank. The engine is classified as a four-cycle machine in that the crankshaft makes two complete revolutions for each power stroke of a piston. The crankshaft is mated directly to the generator rotor at the flywheel and drives the generator along with the following engine components: fuel oil pump, main lubricating oil pump, main cooling water pump, the mechanical and overspeed governors, and the camshafts which control impulse pumps and valve timing.

The electrical generator is an Electric Products Model 1160, horizontal engine type, AC synchronous generator and is classified as Safety Category I, Class 1E. One end of the generator is supported by its connection to the crankshaft of the flywheel; the other end being supported by a bearing mounted in a pedestal. The generator is rated for 5500 kw at a 0.8 power factor and produces 4160 volts at 60 Hertz for 3 phase distribution.

The support systems are integral to the diesel generator except for essential service water which is required for removing heat from the engine's jacket water cooling system and diesel-generator room ventilation which maintain proper room temperature and venting capability.

The diesel generator support systems consist of the diesel fuel oil system, the diesel engine cooling water system, the diesel starting air system, the diesel engine lubrication system, and the diesel engine combustion air and exhaust systems.

<u>Diesel Generator Capacity</u>

Each diesel generator has ample capacity to sequentially start and accelerate all needed engineered safety features and emergency shutdown loads in the event of the simultaneous occurrence of a total loss of offsite power, and a loss of coolant accident. UFSAR Table 8.3-5 (Attachment 10) details the loading sequence of each diesel generator under the circumstances noted in the table.

The Unit 1 loads listed on Divisions 11 and 12 are the loads required in the event of a loss of offsite power coincident with a loss of coolant accident. The Unit 2 loads listed on Divisions 21 and 22 are the loads required in the event of a loss of offsite power and no loss of coolant accident. In addition, the loads designated by note (e) (A.5., B.2., and C.3.) on Table 8.3 5 are also required in the event of loss of offsite power with no loss of coolant accident but are powered from Unit 1, as shown, unless there is an outage on Unit 1 as explained in note e.

The horsepower and kW loads listed in Table 8.3-5 are the nameplate ratings for each load. Diesel generator loading is evaluated and monitored by the Electrical Load Monitoring System for Alternating Current Loads (ELMS-AC). The horsepower values used in the ELMS-AC models for determination of Diesel Generator loading are calculated based upon the maximum flow during the injection phase. The ELMS-AC program applies the manufacturers' motor efficiencies and power factors in the conversion of brake horsepower input to generator output required to power safety-related loads. Actual test data were used, where available. Individual load requirements in the ELMS-AC diesel generator models are updated as required to reflect changes in the plant.

Motor operated valve loads are considered to be of insufficient size and duration to have an impact upon the size and loading of the diesel generators. Therefore, the motor operated valve load will not be listed on Table 8.3-5 since it is not included in the total coincidental BHP on each bus.

The "other loads" listed for Byron and for Braidwood in Table 8.3 5 are the loads on reference drawings shown in Drawings 6E-0-4001 and 20E-0-4001 which are not listed as individual loads in the table. These "other loads" (a) are not required during a LOCA, (b) are not required for hot shutdown, (c) are not automatically connected to the ESF buses, and (d) are applied manually by the operator within the capability of the diesel generators.

The diesel generator is designed to attain rated voltage and frequency and be ready to accept load 10 seconds after the receipt of an automatic start signal.

Station Blackout (SBO) - Diesel Generator Capacity

Byron Station is able to withstand and recover from a station blackout of 4 hours in accordance with the requirements of Regulatory Guide 1.155 (Reference 22). In the event of a station blackout, either one of the two emergency diesel generators for each unit serves as an alternate AC power source for the opposite unit. The alternate AC power source is available within 10 minutes of the onset of the station blackout event and has sufficient capacity and capability to operate equipment necessary to bring and maintain the station in a safe shutdown condition.

Each unit of Byron Station has two emergency diesel generators that provide power to emergency 4.16-kV buses (Divisions 11 and 12 for Unit 1, and Divisions 21 and 22 for Unit 2). There is a manual cross-tie capability between Division 11 of Unit 1 and Division 21 of Unit 2 and, similarly, between Division 12 of Unit 1 and Division 22 of Unit 2. Upon loss of offsite power and failure of both diesel generators to start on one unit, either one of the other unit's diesel generators is capable of providing power for safe shutdown of both units for a 4-hour duration. A worst-case emergency diesel generator loading scenario was used in the station blackout analysis. Equipment necessary for safe shutdown during the station blackout coping duration is available and adequate no matter which emergency diesel generator is used as the alternate AC source. Total emergency diesel generator loading for station blackout is within the 2000-hour rating of the emergency diesel generator. All equipment required for station blackout is capable of being powered from a single remaining diesel generator. The capability for providing power to the blacked-out unit is possible with manual operation of cross-tie switchgear breakers from the main control room.

3.2 Cause Summary for the Failure of SAT 242-2

This section is a summary of the information related to the failure of SAT 242-2 that is available thus far that supports the risk-informed LAR. The available information related to the cause of failure of SAT 242-2 indicates that the SAT failed due internal arcing of the high voltage transformer windings as a result of rising hydrogen generation after maintenance to replace the X2 bushing.

A root cause investigation and analysis of the failure of SAT 242-2 is in-progress in accordance with the EGC Corrective Action Program (CAP). The root cause team is sensitive to the need to verify the ongoing capabilities and any associated risks with the online transformers. Should any results from the root cause question the state of SAT 242-1 or either of the Unit 1 SATs as a result of the findings, EGC will appropriately pursue any necessary changes to the strategy discussed in this request.

Currently, the remaining three SATs at Byron Station (i.e., SAT 142-1, 142-2, and 242-1) are not exhibiting any advanced signs of increased hydrogen gas trends that were seen immediately preceding the SAT 242-2 failure, that would indicate they are susceptible to the same failure mechanism. Transformers are monitored shiftly as part of Operations rounds points and a review of monthly gas trends has shown no long-term leading indicators towards any failure modes. The failure mode as currently understood, was not a predictable fault with advanced, long-term adverse gas trends. The gas trends increased in a short timeframe and could not have been used to predict the event.

While a root cause for the failure of SAT 242-2 is still being determined, there is currently no evidence that SAT 242-1 or any other Byron Station SATs are challenged due to a high voltage internal fault similar to the one that contributed to the failure of SAT 242-2. As discussed in Section 2.1 above, if EGC determines prior to expiration of the extended completion time associated with the failure of SAT 242-1, a common failure mode for any remaining qualified offsite circuits exists, then EGC shall evaluate the Operability of the remaining offsite sources and comply with the appropriate TS Conditions and associated Required Actions.

4.0 TECHNICAL EVALUATION

Following an unanticipated failure of SAT 242-1, the EGC intends to implement a modification to restore power to Buses 241 and 242 from Buses 243 and 244 via Breakers 2411 and 2421, respectively. Bus 243 is powered from Unit Auxiliary Transformer (UAT) 241-1 and Bus 244 is powered from UAT 242-2, which receive power from the output of the Unit 2 main generator.

Figure 6 below is a simplified drawing of a portion of the Byron Station AC electric power system including a depiction of the alternate lineup that will be utilized during the requested extended Completion Time. This is the alignment that was assumed in the analysis of plant risk during the extended Completion Time as discussed in Section 4.3 below and Attachment 7 to this request.

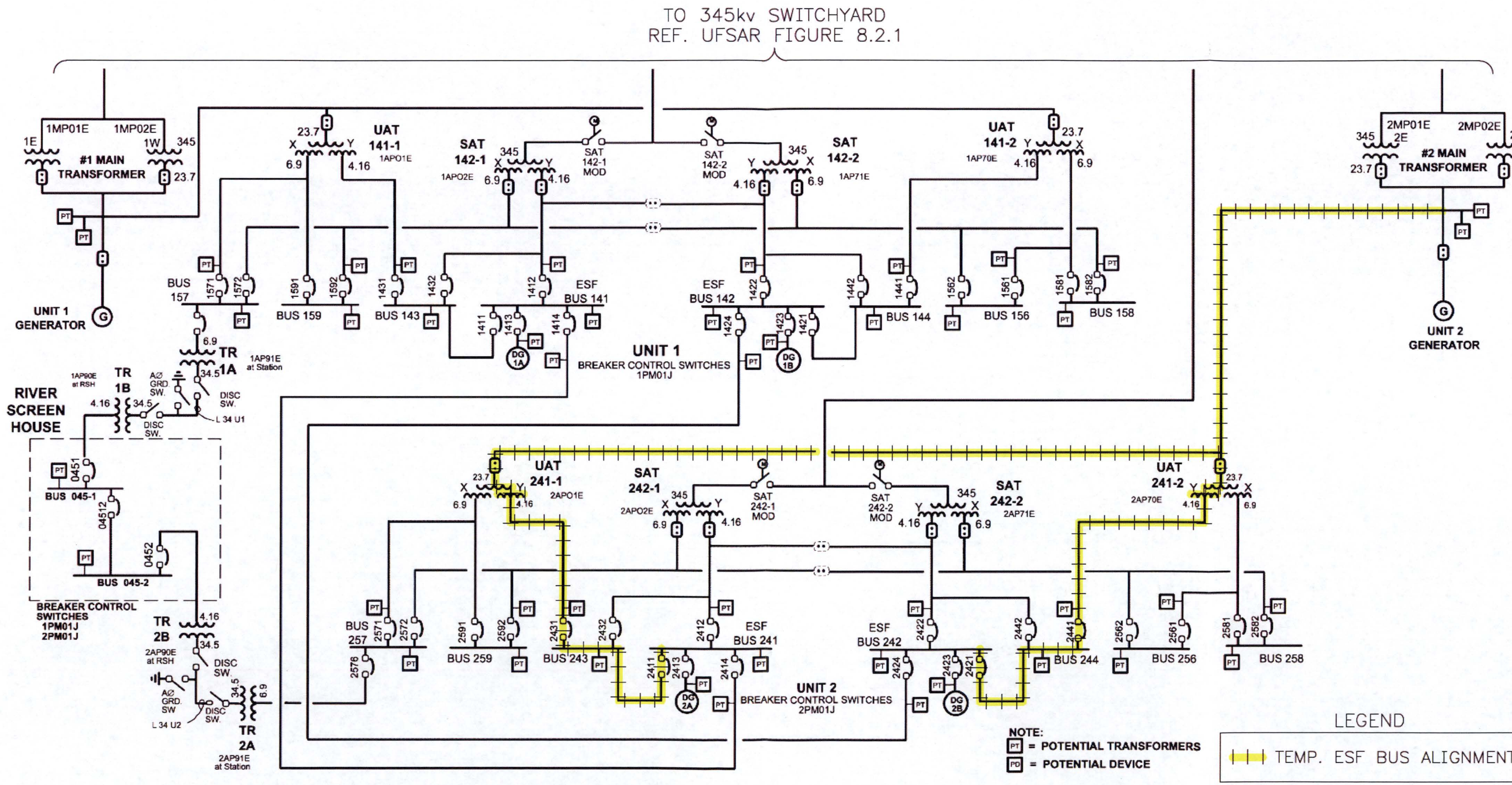

Figure 6: Simplified Drawing of a Portion of the Byron Station, Units 1 and 2 Electric Power System with Temporary Alignment Highlighted (For Information Only)

In the event of a Unit 2 generator trip while in this configuration, AC power will be lost to Unit 2, the reactor will trip, and the DGs will automatically start and power ESF buses. The alternate offsite circuit from the Unit 1 SATs would be available to restore power to the Unit 2 ESF buses in support of cooling the Unit 2 reactor using natural circulation and would also allow the Unit 2 DGs to be secured.

4.1 Deterministic Evaluation (Defense-in-Depth)

In the instance of unavailability of SAT 242-1, ESF buses 241/242 will initially be powered from the emergency diesel generators (EDGs) as Unit 2 would initially experience a LOOP. Operators would then have the option to align ESF buses to the Unit 1 ESF crosstie. Additionally, a plant modification will be installed that will allow ESF buses to be powered from Buses 243/244 via Breakers 2411/2421 as show in Figure 6 above. These buses receive power from Unit Auxiliary Transformer (UAT) 241-1/241-2 and these UATs receive power from the Unit 2 main generator. From this configuration, the EDGs would be returned to standby, allowing the unit to continue operation. Byron Station power system design does not include a generator circuit breaker so in the event of a Unit 2 main generator trip, the main generator and main power transformers are isolated from the station by isolating Switchyard Bus 11. This precludes the capability to back feed the UATs from offsite from the MPTs. AC power will be lost to Unit 2 which will result in a reactor trip, and require the diesel generators to power ESF buses.

In this configuration, several options to power the Unit 2 ESF buses are available. The alternate offsite circuit from the Unit 1 SATs would be available to restore power to the Unit 2 ESF buses, Unit 2 EDGs would be available to power the ESF buses. In the event of an SBO either one of two EDGs from either unit is available as an alternate AC power source for the ESF buses for the opposite unit.

Should all of those AC sources be unavailable, as another level of defense in depth, FLEX coping equipment and strategies are also available that protect and ensure safe facilitation of plant activities following a loss of SAT 242-1, and in the event of additional equipment failures that lead to a loss of all AC sources and after 30 minutes transition the unit into an extended loss of AC power (ELAP). Redundancies, precautionary backup plans, and FLEX equipment are in place and prepared to be utilized on a temporary basis to prevent core damage. These strategies are ensured and validated through simulator scenarios, plant walk-downs, and table-top discussions. 10 CFR 50.62 further requires that each pressurized water reactor have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary feedwater (AF) system and initiate a turbine trip under the conditions indicative of an anticipated transient without scram (ATWS), such as loss of SAT 242-1. In the loss of all AC power, the AF system will be automatically powered by diesel-driven pumps, as explained in UFSAR Section 15.2.6.1.

In addition to sources, defense-in-depth is built into the designs through separation requirements and redundant equipment trains as described in the Offsite Power section above.

As another layer of defense, the transformer health and reliability are monitored as part of Byron Station's Predictive Maintenance Program. The Predictive Maintenance Program is a sub-process of the overall equipment reliability process and the objective is to monitor and trend

equipment condition data. The data is evaluated to provide meaningful information to determine appropriate maintenance action to optimize overall equipment health.
Byron Station's Equipment Reliability Program requires the integration and coordination of a broad range of activities to enable plant personnel to evaluate station equipment, develop and implement a long-term maintenance plan, monitor equipment performance and make continuing adjustments to preventive maintenance tasks and frequencies based on equipment operating experience. It includes the following:

- Determining the basis for maintenance tasks
- Predictive, preventive, proactive and corrective maintenance
- System and component performance monitoring and trending
- Evaluation and resolution of degraded equipment conditions
- Apparent cause evaluations and root cause analyses
- Maintenance Rule implementation
- Use of operating experience data
- Long term equipment maintenance planning
- Life Cycle Management planning

This program is based on Institute of Nuclear Power Operations (INPO) AP-913, "Equipment Reliability Process Description."

4.2 Safety Margin Evaluation

The proposed one-time extension of the Byron Station, TS 3.8.1 Completion Time for loss of one offsite source maintains the margin of safety with the use of normal offsite sources, four (4) emergency diesel generators, compensatory operator actions, alternate non-ESF power used to power ESF buses, and risk management actions. Byron Station will implement limitations of bus loading and specific loading restrictions for various plant configurations. These limitations will include actions to balance loads below loading restrictions for normal operation and abnormal conditions where Unit 2 remains at-power.

A total loss of AC power would require a loss of both Unit 1 SATs, failure of all four emergency diesel generators, and the failure of offsite power through the Unit 2 non-ESF UATs. In this condition, decay heat removal would still be available through use of the B Train of the AF system; which has its own independent diesel-driven pump and an independent battery system. This train of the AF system would supply water to all four steam generators to remove decay heat and support natural circulation cooldown.

The addition of the proposed alternate non-ESF to ESF power supply provides an additional defense-in-depth power supply during at power conditions for Unit 2. Byron Station has a robust design that allows ESF buses to be cross-tied within 10 minutes. One energized ESF bus either from its SAT or EDG has the capability to provide the emergency power supply in case of a transient or accident. In addition, operators would evaluate powering Unit 1 ESF buses from the Unit 2 ESF buses via the Unit 2 UAT in accordance with 10 CFR 50.54x.

Operations will conduct briefs regarding this temporary configuration once per shift and have designated operators in-place to respond to an electrical distribution system transient.

Operations will have procedural guidance based upon the engineering model of the bus loading under current normal loads and with loads that would auto start under transient or accident conditions. This analysis will be a formal technical evaluation that shows that bus loading to be within limitations after compensatory actions are taken by operations following a transient or accident.

4.3 Evaluation of Risk Impacts

The risk associated with extending the Byron Station one-time TS 3.8.1, Condition A, Required Action A.2, Completion Time for the emergent failure of SAT 242-1 from the current 72 hours to 79 days has been evaluated PRA models that meet all scope and quality requirements in NRC Regulatory Guide (RG) 1.200, Revision 2 (Reference 1). This plant-specific risk assessment followed the guidance in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk- Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3, dated January 2018 (Reference 10), and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," Revision 1, dated May 2011 (Reference 11).

4.3.1 Tier 1: Probabilistic Risk Assessment Capability and Insights

The baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) contributions from the PRA models are provided in Section 3.1.1 of Attachment 7. The risk impact associated with a one-time extension is provided in Section 3.5 of Attachment 7 and meets the acceptance criteria in RG 1.177, Revision 1 (Reference 11) where effective compensatory measures are implemented to reduce the sources of increased risk.

The results of this assessment are summarized as follows:

Unit 1 COMPARISON OF INDIVIDUAL HAZARD GROUP RESULTS TO ACCEPTANCE GUIDELINES

	DELTA CDF	DELTA LERF
Internal Events and Internal Floods	1.8E-06	1.8E-08
Internal Fires	1.2E-06	5.0E-08
Seismic	Negligible	Negligible
Other Hazard Groups	Negligible	Negligible
Total Values	3.0E-06	6.8E-08
Acceptance Guideline	Total ICDP = 1.0E-05(1)	Total ICLERP = 1.0E-06(2)
Time to reach Acceptance Guideline	> 1 year	> 1 year

(1) Per RG 1.177 a value between 1E-06 and 1E-05 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

(2) Per RG 1.177 a value between 1E-07 and 1E-06 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

Unit 2 COMPARISON OF INDIVIDUAL HAZARD GROUP RESULTS TO ACCEPTANCE GUIDELINES

	DELTA CDF	DELTA LERF
Internal Events and Internal Floods	3.3E-05	1.3E-06
Internal Fires	1.3E-05	1.9E-06
Seismic	2.2E-08	6.2E-10
Other Hazard Groups	Negligible	Negligible
Total Values	4.6E-05	3.2E-6
Acceptance Guideline	Total ICDP = 1.0E-05(1)	Total ICLERP = 1.0E-06(2)
Time to reach Acceptance Guideline	> 79 days	> 114 days

(1) Per RG 1.177 a value between 1E-06 and 1E-05 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

(2) Per RG 1.177 a value between 1E-07 and 1E-06 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

The results indicate a one-time extension up to 79 days would not exceed the ICCDP and ICLERP risk limits for Unit 2, while Unit 1 would not exceed the thresholds within one year.

4.3.2 Tier 2: Avoidance of Risk Significant Plant Configurations

The following compensatory measures all serve to lessen the calculated increase in the core damage and large early release risk during the extended Tech Spec Completion Time.

The risk-informed evaluation identified a number of compensatory measures that will be implemented during the extended TS Completion Time configuration to assure the risk impacts are acceptably low. These are discussed in detail in Sections 3.2 and 3.3 of BY-LAR-012 (Attachment 7) and summarized below.

The assessment of risk from internal events and internal fires identified the following actions as important compensatory measures that will help to reduce the overall risk during the performance of the extended CT:

1. Protect the following components
    - o Unit 2 Diesel Driven Auxiliary Feedwater (AF) Pump, 2AF01PB
    - o All four Unit 1 and Unit 2 diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB
2. Limit elective maintenance unavailability on the following components
    - o 2AF01PB, Unit 2 diesel driven AF pump

- 2AF01PA, Unit 2 motor driven AF pump
- 2DG01KA, Unit 2 Diesel Generator A
- 2DG01KB, Unit 2 Diesel Generator B
- 2AP231X2, Motor Control Center (MCC) 231X2
- 2AP232X1, MCC 232X1
- 1AP132X1, MCC132X1

3. Each shift, operators should brief on the following actions:
   - Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
   - Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
   - Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate essential service water (SX) system cooling
   - Aligning fire protection cooling to centrifugal charging (CV) pumps, 2CV01PA and 2CV01PB, upon loss of SX
   - Locally failing air to the Unit 2 AF Flow Control, 2AF005, valves on loss of main feedwater
   - Byron Station Procedure BOP DG-22, "Diesel Generator Operation after Auto Start"
   - Byron Station Procedure 2BOA ELEC-4, "Loss of Offsite Power Unit 2"
   - Byron Station Procedure 2BEP ES-0.1, "Reactor Trip Response Unit 2," actions concerning natural circulation cooldown
   - Byron Station Procedure BOP DO 16, "Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank"
   - Byron Station Procedure BOP CC 10, "Alignment of the U-0 Component Cooling Water (CC) Pump and U-0 CC Heat Exchanger (HX) to a Unit"

Based on a review of results from the fire PRA contributors, the following compensatory actions are highlighted as important to reduce the risk from fire events during the performance of the extended TS Condition 3.8.1.A CT:

1. Aside from the period of aligning UAT-to-ESF bus supply, maintain SAT supply feed breakers to ESF buses, 2412 and 2422, racked out

2. Aside from the period of aligning UAT-to-ESF bus supply, open test switches for breakers 2412/2422 to prevent lockout relays from impacting breakers 2413 and 2414/2423 and 2424 operation

3. Each shift, operators should brief on the following actions:
   a. Filling the Unit 2 Diesel AF Pump Day Tank from the 125,000 or 50,000 gallon fuel oil storage tanks per 2BOP DO-13
   b. Providing makeup capability to the SX Cooling Tower Basin before inventory is low per BAR 0-37-A8 and BOP SX-12
4. Risk Management Actions (RMAs) applicable for this extended CT window will be completed per OP-AA-201-012-1001, "Operations On-Line Fire Risk Management," (These actions protect against fire impacting key redundant equipment).
5. Prior to entering the TS 3.8.1.A Action Statement for repair of Unit 2 SATs, an operating crew shift briefing and pre-job walkdowns are suggested to be conducted to reduce and manage transient combustibles and to alert the staff about the increased sensitivity to fires in the fire zones specified in Table 3.3-5 of Attachment 7 is shown below. Operating crew shift briefings will continue to be conducted every shift throughout the duration of the CT period. Additionally, planned hot work activities in these fire zones should be minimized during the time within the extended TS Condition 3.8.1.A CT. In the event of an emergent issue requiring hot work in one of the listed zones, additional compensatory actions will be developed to minimize the risk of fire. The fire zones listed in Table 3.3-5 of Attachment 7 were identified based on risk significance in the FPRA results. Walkdowns are intended to reduce the likelihood of fires in certain zones by limiting transient combustibles, ensuring transients, if required to be present, be located away from fixed ignition sources, and eliminating or isolating potential transient ignition sources, (e.g., energized temporary equipment and associated cables). The following table identifies the risk-significant fire zones to which compensatory actions apply.

Fire Zone(1)	Fire Zone Description
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room
5.2-1	Division 11 ESF Switchgear Room
5.2-2	Division 21 ESF Switchgear Room
2.1-0	Control Room
11.4C-0	Radwaste/Remote Shutdown Control Room
11.7-0	Auxiliary Building HVAC Exhaust Complex
11.6-0	Auxiliary Building General Area, 426' El.

4.3.3 Tier 3: Risk Informed Configuration Management

Risk would also be managed during the extended completion time via the Maintenance Rule 10 CFR 50.65(a)(4) *Configuration Risk Management Program (CRMP),* which has been reviewed in a previous Byron Station risk-informed Technical Specifications change request (Reference 7).

Additional Maintenance Rule (MR) Program Information

The reliability and availability of the diesel generators (DGs) are monitored under the MR Program. If the pre-established reliability or availability performance criteria are exceeded for the DGs, they are considered for 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," Paragraph (a)(1) actions, requiring increased management attention and goal setting in order to restore their performance (i.e., reliability and availability) to an acceptable level. The performance criteria are risk-based and, therefore, are a means to manage the overall risk profile of the plant. An accumulation of large core damage probabilities over time is precluded by the performance criteria.

As of June 2018, all Byron Station DGs are in the 10 CFR 50.65 a(2) MR category (i.e., the DGs are meeting established performance goals). Additionally, the Unit 1 and Unit 2 DGs are currently meeting the NRC Mitigating Systems Performance Index criteria for Emergency AC Power Systems. Activities involving the restoration of a qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical distribution system is not anticipated to result in exceeding the current established MR Program or NRC Performance Index criteria for DGs.

Plant modifications and procedure changes are monitored, assessed and dispositioned. Evaluation of changes in plant configuration or PRA model features are dispositioned by implementing PRA model changes or by qualitatively assessing the impact of the changes on the CRMP assessment tool. Procedures exist for the control and application of CRMP assessment tools, and include a description of the process when the plant configuration of concern is outside the scope of the CRMP assessment tool.

Technical Adequacy of the PRA

Section 4 of Attachment 7 demonstrates that the quality and level of detail of the PRA model used in the requested change meet NRC requirements in NRC RG 1.200, Revision 2 (Reference 1). Additionally, it provides the status of plant modifications and evaluations credited in the PRA models, which all have been completed for Byron Station, Units 1 and 2. All the PRA models described in the application have been peer reviewed and there are no PRA upgrades that have not been peer reviewed. The findings and dispositions from the peer reviews impacting PRA technical quality are described in Section 4 of Attachment 7. Included in Attachment 7 are the Facts and Observations (F&Os) from the indicated peer reviews impacting PRA quality, and do not include F&Os describing optional suggestions or industry best practices. The peer review finding dispositions show that all peer review findings meet the associated ASME PRA Standard RA-Sa-2009 (Reference 9) supporting requirements to Capability Category II or have been addressed with regards to impact on this application. Thus, all the PRA models described herein comply with all scope and quality requirements per RG 1.200, Revision 2 (Reference 1).

The PRA models credited in this request are the same PRA models credited in the Risk-Informed Categorization in Accordance With 10 CFR 50.69 application dated September 1, 2017 (Reference 3) with plant modifications described herein and documented in Attachment 7.

PRA Uncertainty Evaluations

Key Byron Station PRA model specific assumptions and sources of uncertainty for this application are identified and dispositioned in Section 3.6 of Attachment 7. The conclusion of this review is that no additional sensitivity analyses are required to address Byron Station PRA model specific assumptions or sources of uncertainty for this application.

4.4 Conformance with the Guidance in Branch Technical Position (BTP) 8-8, "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions," dated February 2012

BTP 8-8 provides general guidance for the review of TS Completion Time extensions for either EDGs or offsite power sources. The BTP describes the NRC approach to review such extensions to Completion Times (either one-time or permanent) using a combination of a PRA risk-informed approach integrated with deterministic evaluations regarding the impact on defense-in-depth in the plant's design and maintaining adequate safety margin. The purpose of BTP 8-8 is to provide guidance from a deterministic perspective in reviewing such amendment requests.

The deterministic evaluation described in BTP 8-8 states that, during the extended completion time for an inoperable offsite source, a supplemental power source should be available as a backup to the inoperable offsite power source to maintain the defense-in-depth philosophy of the electrical system to meet its intended safety function. The supplemental power source has the capacity to bring a unit from Mode 1 operation to safe shutdown in case of a loss of offsite power concurrent with a single failure. The objective of this supplemental power source for an inoperable offsite power source is to avoid a potential extended station blackout event during

the extended completion time and enable safe shutdown of the unit if the normal power sources cannot be restored in a timely manner. The supplemental power source maintains the defense-in-depth of the electrical power sources during the extended completion time.
The BTP further discusses how multi-unit sites may credit their existing EDGs as the supplemental AC source. For the existing Class 1E EDGs to qualify as a supplemental AC source in the adjacent unit (for extending the Completion Time), the EDG must have excess capacity to meet their unit's LOOP safe shutdown loads while complying with single failure criteria, and have spare capacity to support the other unit to bring the plant to cold shutdown.

As discussed previously, Byron Station is designed with the requisite EDG capacity and design features to meet this provision. In the event of a station blackout, either one of the two emergency diesel generators for each unit serves as an alternate AC power source for the opposite unit. The alternate AC power source is available within 10 minutes of the onset of the station blackout event and has sufficient capacity and capability to operate equipment necessary to bring and maintain the station in a safe shutdown condition. Upon loss of offsite power and failure of both diesel generators to start on one unit, either one of the other unit's diesel generators is capable of providing power for safe shutdown of both units for a 4-hour duration.

The EDG capacity and the Byron electric power design features (including installed unit cross-tie and operating procedures) are consistent with the provisions of BTP 8-8 regarding providing a supplemental power source. This ensures the defense-in-depth and safety margin aspects of the BTP 8-8 deterministic evaluations are satisfied.

<u>Conformance with the NRC Expectations in BTP 8-8 for Providing Regulatory Commitments</u>

As discussed in BTP 8-8, the NRC expects that licensee will provide the several regulatory commitments when requesting the extension of the TS Completion Times associated with the restoration of power sources required by LCO 3.8.1. These expectations are defined in the bullets below, followed by the Actions EGC is proposing to address each expectation.

- The extended AOT will be used no more than once in a 24-month period (or refueling interval) on a per diesel basis to perform EDG maintenance activities, or any major maintenance on offsite power transformer and bus.

<u>EGC Action</u>
EGC is proposing a one-time, risk-informed extension to TS 3.8.1, Required Action A.2, related to an extended TS Completion Time that will be limited to the period of time required to restore the offsite circuits required by LCO 3.8.1 following an unanticipated failure of SAT 242-1. Therefore, EGC is not providing any commitments associated with this expectation.

- The preplanned maintenance will not be scheduled if severe weather conditions are anticipated.

EGC Action
Since the proposed change is a contingency action associated with an unanticipated failure of SAT 242-1, and not a current plant condition or pre-planned maintenance, EGC is not providing any commitments associated with this expectation.

- 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 AOT.

EGC Action
EGC has included this action as a new regulatory commitment in Attachment 6. Grid conditions will be evaluated in accordance with the Byron Station Nuclear Plant Interface Requirement (Attachment 9) and station procedures.

- Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or LOOP will be avoided. In addition, no discretionary switchyard maintenance will be performed.

EGC Action
EGC has included this action as a new regulatory commitment in Attachment 6.

- 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.

EGC Action
The risk-informed analysis of the proposed one-time extension of TS 3.8.1 Required Action A.2 CT assumed that average testing and maintenance practices would continue to be employed during the duration of the requested CT extension. EGC will continue to perform all required TS Surveillance Requirements; therefore, no regulatory commitment is proposed associated with this NRC expectation.

- Steam-driven emergency feed water pump(s) in case of PWR units, and Reactor Core Isolation Cooling and High Pressure Coolant Injection systems in case of BWR units, will be controlled as "protected equipment."

EGC Action
Byron Station, Units 1 and 2 are of the pressurized water reactor design, and the auxiliary feedwater (AF) system includes diesel-driven AF pumps in lieu of steam-driven pumps. EGC is

proposing to include this expectation for Unit 2, along with the protection of all Unit 1 and Unit 2 diesel generators as new Renewed Facility Operating License, Appendix C, Condition 1. In addition to protecting this equipment, EGC will take the following actions if these components become inoperable, for reasons other than the performance of TS SRs: *EGC shall comply with the appropriate Required Actions for the associated Condition as defined in the TS.*

4.5 Operator Training

Prior to implementation of the proposed change Byron Station Operations Training will provide licensed operators training and simulator scenarios based on the following:

- Electrical alignment and governing procedures following the loss of SAT 242-1
- Compensatory operator actions during the extended completion time
- The expected plant response of an electrical distribution transient or plant trip while the Unit 2 is in the configuration where the UATs are powering the ESF buses.
- The required operator response and appropriate procedure guidance of an electrical distribution transient or plant trip while Unit 2 is in the configuration where the UATs are powering the ESF buses.

4.6 Conclusions

This request has been evaluated consistent with the key principles identified in RG 1.177 for risk-informed changes to the TSs and demonstrates that the risk from the proposed change is acceptably small. The evaluation with respect to these principles is summarized below. The risk evaluation supports a one-time extension of TS 3.8.1, Required Action A.2, from 72 hours to 79 days.

The proposed change meets the current regulations unless it is explicitly related to a requested exemption.

The proposed change does not propose to deviate from existing regulatory requirements, and compliance with existing regulations is maintained by the proposed one-time change to the plant's TS requirements.

The proposed change is consistent with the defense-in-depth philosophy.

Defense-in-depth is maintained during the proposed configuration through compliance with the NRC guidance in BTP 8-8. Compensatory measures are identified to strengthen the level of defense-in-depth and reduce overall risk.

The proposed change maintains sufficient safety margins.

The proposed TS change is consistent with the principle that sufficient safety margins are maintained based on the fact that while in the proposed configuration, safety analyses acceptance criteria in the UFSAR are met, assuming there are no additional failures.

When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.

A risk evaluation was performed that considers the impact of the proposed change with respect to the risks due to internal events, internal fires, seismic events and other external hazards. The evaluation of these risks due to the planned configuration demonstrates that the impact on the likelihood of core damage and large early release is within the risk acceptance guideline with sufficient compensatory measures.

The impact of the proposed change should be monitored using performance measurement strategies.

EGC's Configuration Risk Management Program will effectively monitor the risk of emergent conditions during the period of time that the proposed change is in effect. This will ensure that any additional risk increase due to emergent conditions is appropriately managed.

5.0 REGULATORY EVALUATION

5.1 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine applicable regulations and requirements.

GDC 5 - Sharing of Structures, Systems, and Components, "Structures, systems, and components important to safety shall not be shared between nuclear power Units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions including, in the event of an accident in one Unit, an orderly shutdown and cooldown of the remaining Unit."

GDC 17 - Electric Power Systems, "An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to ensure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electrical power circuit, to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to ensure that core cooling, containment integrity, and other vital safety functions are maintained. Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power Unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies."

GDC 18 - Inspection and Testing of Electric Power System, "Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system and the transfer of power among the nuclear power Unit, the offsite power system, and the onsite power system."

NRC Regulatory Guide (RG) 1.53, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems," dated June 1973 (Reference 17).

RG 1.62, "Manual Initiation of Protective Actions," dated October 1973 (Reference 18).

RG 1.75, "Physical Independence of Electrical Systems," Revision 1, dated January 1975 (Reference 19).

RG 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants," Revision 1, dated January 1975 (Reference 20)

RG 1.93, "Availability of Electric Power Sources," dated December 1974 (Reference 21). The current CT associated with inoperable AC power source(s) is intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide (RG) 1.93 is referenced in the TS Bases for actions associated with TS 3.8.1. RG 1.93 provides operating restrictions (i.e., CT and maintenance limitations) that the NRC considers acceptable if the number of available AC power sources is one less than the LCO. RG 1.93 specifically states, "If the available AC power sources are one less than the LCO, power operation may continue for a period that should not exceed 72 hours if the system stability and reserves are such that a subsequent single failure (including a trip of the Unit's generator, but excluding an unrelated failure of the remaining offsite circuit if this degraded state was caused by the loss of an offsite source) would not cause total loss-of-offsite power." RG 1.93 additionally states, "The operating time limits delineated above are explicitly for corrective maintenance activities only."

RG 1.155, "Station Blackout," dated August 1988 (Reference 22)

RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3, dated January 2018

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," Revision 1, dated May 2011 (Reference 11)

RG 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, Revision 2, dated March 2009 (Reference 1)

Analysis

Only conformance with RG 1.93 is affected by this proposed change. According to RG 1.93, operation may continue with one inoperable offsite circuit for a period not to exceed 72 hours. If the proposed change is approved, EGC will continue to conform to this RG with the exception that the allowed CT for restoration of an offsite circuit will be increased on a one-time basis to 79 days.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.2 Precedent

This license amendment request is similar in nature to the following amendment that was previously approved by the NRC to allow a one-time extension of the Completion Time for an inoperable diesel generator for Palo Verde, Unit 3 (i.e., Accession No. ML17004A020). That amendment provided sufficient time for the Arizona Public Service Company (APS) to complete the repairs to the Palo Verde Nuclear Generating Station 3B diesel generator.

> Letter from S. P. Lingam (NRC) to R. M. Bement (APS), "Palo Verde Nuclear Generating Station, Unit 3- Issuance of Amendments Re: Revision to Technical Specification 3.8.1, 'AC [Alternating Current] Sources – Operating' (Emergency Circumstances) (CAC NO. MF9019)," dated January 4, 2017

5.3 No Significant Hazards Consideration

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (EGC) requests amendments to Renewed Facility Operating License Nos. NPF-37 and NPF-66, Appendix C for Byron Station, Units 1 and 2, and Technical Specification (TS) 3.8.1, "AC Sources – Operating." Specifically, adding two new Operating License Conditions and extending, on a one-time basis, the allowable Completion Time (CT) of Required Action A.2 for one inoperable offsite circuit, from 72 hours to 79 days. This change is only applicable to Unit 2 system auxiliary transformers (SATs) 242-1 and 242-2, and will expire on February 14, 2019. This change is needed to provide sufficient time to restore a required qualified offsite circuit to an Operable status and avoid an unnecessary shutdown of Byron Station, Units 1 and 2. EGC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10CFR50.92, "Issuance of amendment," as discussed below:

The proposed change will provide a risk-informed, one-time revision to the TS CT for one qualified offsite circuit inoperable for Byron Station Units 1 and 2 from 72 hours to 79 days. The extension of the TS CT does not involve a change to the design or operation of any structure, system, or component credited in the plant safety analysis. There is no change to the plant accident or transient response or analyses during the extended period of one qualified offsite circuit being inoperable. The proposed change only extends the period of time the plant is allowed to be in a configuration currently allowed by the TS and adds specific Operating License Conditions to support the CT extension. The extension of the TS CT does not affect the design of the Unit 1 SAT or either unit's Emergency Diesel Generators (EDGs), the interface of the SAT or EDGs with other plant systems, or the operating characteristics or reliability of the SAT or EDGs. Both units would continue to respond to a Loss of Offsite Power (LOOP) as currently analyzed. Therefore, the probability of a previously evaluated accident is not significantly increased.

According to 10 CFR 50.92, "Issuance of amendment," paragraph (c), a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendments would not:

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

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

3) Involve a significant reduction in a margin of safety.

EGC has evaluated the proposed changes for Byron Station, using the criteria in 10 CFR 50.92, and has determined that the proposed changes do not involve a significant hazards consideration. The following information is provided to support a finding of no significant hazards consideration.

1) Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed change will provide a one-time, risk-informed revision to the CT for the loss of one offsite source for Byron Station, Units 1 and 2 from 72 hours to 79 days. The proposed one-time extension of the CT for the loss of one offsite power circuit does not significantly increase the probability of an accident previously evaluated. The TSs will continue to require equipment that will power safety related equipment necessary to perform any required safety function. The one-time extension of the CT to 79 days does not affect the design of the Unit 1 SATs, the interface of the SATs with other plant systems, the operating characteristic of the SATs, or the reliability of the SATs.

The consequence of a loss of offsite power (LOOP) event has been evaluated in the Byron Station Updated Final Safety Analysis Report (Reference 23) and the Station Blackout evaluation. Increasing the CT for one offsite power source on a one-time basis from 72 hours to 79 days does not increase the consequences of a LOOP event nor change the evaluation of LOOP events. The plant will continue to respond to a LOOP in the same manner and with the same consequences as previously evaluated. Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2) Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed change does not result in a change in the manner in which the electrical distribution subsystems provide plant protection. The proposed change will only affect the time allowed to restore the operability of the offsite power source through a SAT. The proposed change to extend the TS CT does not affect the configuration, or operation of the plant. The proposed change to the CT will facilitate completion of repairs which will restore plant design to its as-built configuration, and will eliminate the necessity to shut down both Units if SAT 242-1 fails or requires maintenance that goes beyond the current TS CT of 72 hours. This change will support the restoration of the long-term reliability of the 345kV offsite circuit SAT which is common to both Byron Units.

There are no changes to the SATs or the supporting systems operating characteristics or conditions. The change to the CT does not change any existing accident scenarios, nor create any new or different accident scenarios. In addition, the change does not impose any new or different requirements or eliminate any existing requirements. The change does not alter any of the assumptions made in the safety analysis.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

3) Do the proposed changes involve a significant reduction in a margin of safety?

Response: No.

The proposed change does not affect the acceptance criteria for any analyzed event nor is there a change to any safety limit. The proposed change does not alter the manner in which safety limits, limiting safety system settings, or limiting conditions for operation are determined. Neither the safety analyses nor the safety analysis acceptance criteria are affected by this change. The proposed change will not result in plant operation in a configuration outside the current design basis. The proposed activity only increases, for a one-time unanticipated occurrence, the period when Byron Station, Units 1 and 2 may operate with one offsite power source. The margin of safety is maintained by maintaining the ability to safely shut down the plant and remove residual heat.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above evaluation, EGC concludes that the proposed amendments do not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

5.4 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

EGC has evaluated the proposed amendments for environmental considerations. The review has resulted in the determination that the proposed amendments would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendments do not involve (i) a significant hazards consideration, (ii) a significant change in the types or a significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendments.

7.0 REFERENCES

1. Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Revision 2, dated March 2009

2. NEI 00-02, *Probabilistic Risk Assessment (PRA) Peer Review Process Guidance, Nuclear Energy Institute*, dated 2000

3. *License Amendment Request to Revise Technical Specifications to implement Risk Informed Completion Time* (ADAMS Accession Number ML15218A300), dated July 31, 2015

4. NUREG/CR-6850, *EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities,* dated September 2005

5. NUREG-1855, *Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making*, dated March 2009

6. EPRI TR-1016737, *Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments*, dated December 2008

7. *Byron Station, Unit Nos. 1 and 2 - Issuance of Amendments Re: One-Time Extension of Essential Service Water Train Technical Specification Completion Time (TAC Nos. ME2293 and ME2294)* (ADAMS Accession Number ML100740224), dated April 9, 2010

8. Braidwood and Byron - *Application to Adopt 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,"* (ADAMS Accession Number ML17244A093) dated September 1, 2017

9. ASME/ANS RA-Sa-2009, *Standard for Level I/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications*, Addendum A to RA-S-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, dated February 2009

10. Regulatory Guide 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*, Revision 2, dated April 2015

11. Regulatory Guide 1.177, *An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications*, Revision 1, dated May 2011.

12. WCAP-16175-P-A, *Model for Failure of RCP Seals Given Loss of Seal Cooling in CE NSSS Plants*, Revision 0, March 2007

13. NRC Letter dated January 4, 2017, *Palo Verde, Unit 3 - Issuance of Amendment No. 200, Revise Technical Specification 3.8.1, "AC Sources - Operating," for One-Time Extension of the Diesel Generator Completion Time, Risk-Informed (Emergency Circumstances)* (CAC No. MF9019) (ADAMS Accession Number ML17004A020)

14. Engineering Evaluation BY-LAR-012, *Risk Assessment Input for the Byron One-Time Technical Specification Change for Condition 3.8.1.A Completion Time from*

72 Hours to 79 days for Units 1 and 2, dated August 9, 2018

15. 10 CFR 50, Appendix A, General Design Criterion 17, Electric Power Systems
16. IEEE 308, *Institute of Electric and Electronic Engineers, Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations,* dated 1971
17. Regulatory Guide 1.53, Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems, dated June 1973
18. Regulatory Guide 1.62, Manual Initiation of Protective Actions, Revision 0 dated October 1973
19. Regulatory Guide 1.75, Physical Independence of Electrical Systems, Revision 2, dated September 1978
20. Regulatory Guide 1.81, Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants, Revision 1, dated January 1975
21. Regulatory Guide 1.93, Availability of Electric Power Sources, Revision 0, dated December 1974
22. Regulatory Guide 1.155, Station Blackout, Revision 0, dated August 1988
23. Byron/Braidwood Nuclear Stations Updated Final Safety Analysis Report (UFSAR), NRC Docket Nos. STN 50-454, STN 50-455, and 72-68
24. IEEE 279, *Institute of Electric and Electronic Engineers, Criteria for Protection Systems for Nuclear Power Generating Stations*, 1971
25. ASME *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, dated May 30, 2000

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 2

PROPOSED UNIT 1 RENEWED FACILITY OPERATING LICENSE, APPENDIX C CHANGES (MARKUP)

Appendix C
INSERT

APPENDIX C

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-37

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
127	The safety limit equation specified in TS 2.1.1.3 regarding fuel centerline melt temperature (i.e., less than 5080 °F, decreasing by 58 °F per 10,000 MWD/MTU burnup as described in WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995) is valid for uranium oxide fuel without the presence of poisons mixed homogeneously into the fuel pellets. If fuel pellets incorporating homogeneous poisons are used, the topical report documenting the fuel centerline melt temperature basis must be reviewed and approved by the NRC and referenced in this license condition. TS 2.1.1.3 must be modified to also include the fuel centerline melt temperature limit for the fuel with homogeneous poison.	With implementation of the amendment

Insert

ATTACHMENT 2 - PROPOSED INSERT FOR BYRON STATION, UNIT 1, RENEWED FACILITY OPERATING LICENSE, APPENDIX C

ATTACHMENT 2 INSERT

1. The Unit 1 diesel generators (DGs) (i.e., 1DG01KA and 1DG01KB) will be protected in accordance with the Exelon Generation Company, LLC (EGC) Procedure OP-AA-108-117, "Protected Equipment Program," for the duration of the temporary extended Technical Specification (TS) 3.8.1, "AC Sources-Operating," Condition A, Required Action A.2, Completion Time associated with the failure of Unit 2, System Auxiliary Transformer (SAT) 242-1, to aid in avoiding inadvertent impacts from walkdowns, inspections, maintenance, and potential for transient combustible fires.

   All TS Surveillance Requirements (SRs) will continue to be performed as required to ensure DG Operability. If either Unit 1 DG becomes inoperable, for reasons other than the performance of TS SRs, EGC shall comply with the appropriate Required Actions for the associated Conditions as defined in the TSs.

2. If EGC determines prior to expiration of the extended TS Completion Time associated with the failure of SAT 242-1, a common failure mode for any remaining qualified offsite circuits exists, then EGC shall evaluate the Operability of the remaining offsite sources and comply with the appropriate TS Conditions and associated Required Actions.

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 3

PROPOSED UNIT 2 RENEWED FACILITY OPERATING LICENSE, APPENDIX C CHANGES (MARKUP)

Appendix C
Insert

APPENDIX C

ADDITIONAL CONDITIONS

RENEWED FACILITY OPERATING LICENESE NO. NPF-66

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
127	The safety limit equation specified in TS 2.1.1.3 regarding fuel centerline melt temperature (i.e., less than 5080 °F, decreasing by 58 °F per 10,000 MWD/MTU burnup as described in WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995) is valid for uranium oxide fuel without the presence of poisons mixed homogeneously into the fuel pellets. If fuel pellets incorporating homogeneous poisons are used, the topical report documenting the fuel centerline melt temperature basis must be reviewed and approved by the NRC and referenced in this license condition. TS 2.1.1.3 must be modified to also include the fuel centerline melt temperature limit for the fuel with homogeneous poison.	With implementation of the amendment

INSERT

ATTACHMENT 3 -PROPOSED INSERT FOR BYRON STATION, UNIT 2, RENEWED FACILITY OPERATING LICENSE, APPENDIX C

ATTACHMENT 3 INSERT

1. The following equipment will be protected in accordance with the Exelon Generation Company, LLC (EGC) Procedure OP-AA-108-117, "Protected Equipment Program," for the duration of the temporary extended Technical Specification (TS) 3.8.1, "AC Sources-Operating," Condition A, Required Action A.2, Completion Time associated with the failure of Unit 2, System Auxiliary Transformer (SAT) 242-1, to aid in avoiding inadvertent impacts from walkdowns, inspections, maintenance, and potential for transient combustible fires:

   a. Unit 2 Diesel Driven Auxiliary Feedwater Pump (2AF01PB)
   b. All Unit 2 Diesel Generators (i.e., 2DG01KA and 2DG01KB)

   All TS Surveillance Requirements (SRs) will continue to be performed as required to ensure equipment Operability. If any of this equipment becomes inoperable, for reasons other than the performance of TS SRs, EGC shall comply with the appropriate Required Actions for the associated Conditions as defined in the TSs.

2. If EGC determines prior to expiration of the extended TS Completion Time associated with the failure of SAT 242-1, a common failure mode for any remaining qualified offsite circuits exists, then EGC shall evaluate the Operability of the remaining offsite sources and comply with the appropriate TS Conditions and associated Required Actions.

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 4 - PROPOSED TECHNICAL SPECIFICATIONS CHANGE (MARKUPS)

3.8.1-1

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits per bus between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Two Diesel Generators (DGs) capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-------------------------------------NOTE-------------------------------------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more buses with one required qualified circuit inoperable. --------NOTE---------- For the failure of Unit 2 System Auxiliary Transformer 242-1, restore the required qualified circuit to OPERABLE status within 79 days. --------------------------	A.1	Perform SR 3.8.1.1 for the required OPERABLE qualified circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours <u>AND</u> 17 days from discovery of failure to meet LCO

(continued)

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 5 – REVISED (CLEAN) TECHNICAL SPECIFICATIONS PAGE

3.8.1-1
3.8.1-2

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits per bus between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Two Diesel Generators (DGs) capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more buses with one required qualified circuit inoperable.	A.1	Perform SR 3.8.1.1 for the required OPERABLE qualified circuits.	1 hour AND Once per 8 hours thereafter -------NOTE------ For the failure of Unit 2 System Auxiliary Transformer 242-1, restore the required qualified circuit to OPERABLE status within 79 days. -----------------
	AND		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours AND 17 days from discovery of failure to meet LCO

(continued)

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 6

SUMMARY OF COMPENSATORY MEASURES AND REGULATORY COMMITMENTS

ATTACHMENT 6

COMPENSATORY MEASURES AND SUMMARY OF REGULATORY COMMITMENTS

Compensatory Measures

The assessment of risk from internal events and internal fires identified the following actions as important compensatory measures that will help to reduce the overall risk during the performance of the extended CT:

1. Protect the following components
   - Unit 2 Diesel Driven Auxiliary Feedwater (AF) Pump, 2AF01PB
   - All four Unit 1 and Unit 2 diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB
2. Limit elective maintenance unavailability on the following components
   - 2AF01PB, Unit 2 diesel driven AF pump
   - 2AF01PA, Unit 2 motor driven AF pump
   - 2DG01KA, Unit 2 Diesel Generator A
   - 2DG01KB, Unit 2 Diesel Generator B
   - 2AP231X2, Motor Control Center (MCC) 231X2
   - 2AP232X1, MCC 232X1
   - 1AP132X1, MCC132X1
3. Each shift, operators should brief on the following actions:
   - Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
   - Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
   - Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate essential service water (SX) system cooling
   - Aligning fire protection cooling to centrifugal charging (CV) pumps, 2CV01PA and 2CV01PB, upon loss of SX
   - Locally failing air to the Unit 2 AF Flow Control, 2AF005, valves on loss of main feedwater
   - Byron Station Procedure BOP DG-22, "Diesel Generator Operation after Auto Start"
   - Byron Station Procedure 2BOA ELEC-4, "Loss of Offsite Power Unit 2"
   - Byron Station Procedure 2BEP ES-0.1, "Reactor Trip Response Unit 2," actions concerning natural circulation cooldown
   - Byron Station Procedure BOP DO 16, "Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank"
   - Byron Station Procedure BOP CC 10, "Alignment of the U-0 Component Cooling Water (CC) Pump and U-0 CC Heat Exchanger (HX) to a Unit"

ATTACHMENT 6

COMPENSATORY MEASURES AND SUMMARY OF REGULATORY COMMITMENTS

Based on a review of results from the fire PRA contributors, the following compensatory actions are highlighted as important to reduce the risk from fire events during the performance of the extended TS Condition 3.8.1.A CT:

1. Aside from the period of aligning UAT-to-ESF bus supply, maintain SAT supply feed breakers to ESF buses, 2412 and 2422, racked out
2. Aside from the period of aligning UAT-to-ESF bus supply, open test switches for breakers 2412/2422 to prevent lockout relays from impacting breakers 2413 and 2414/2423 and 2424 operation
3. Each shift, operators should brief on the following actions:
    a. Filling the Unit 2 Diesel AF Pump Day Tank from the 125,000 or 50,000 gallon fuel oil storage tanks per 2BOP DO-13
    b. Providing makeup capability to the SX Cooling Tower Basin before inventory is low per BAR 0-37-A8 and BOP SX-12
4. Risk Management Actions (RMAs) applicable for this extended CT window will be completed per OP AA 201-012-1001, "Operations On-Line Fire Risk Management," (These actions protect against fire impacting key redundant equipment).
5. Prior to entering the TS 3.8.1.A Action Statement for repair of Unit 2 SATs, an operating crew shift briefing and pre-job walkdowns are suggested to be conducted to reduce and manage transient combustibles and to alert the staff about the increased sensitivity to fires in the fire zones specified in Table 3.3-5 of Attachment 7 is shown below. Operating crew shift briefings will continue to be conducted every shift throughout the duration of the CT period. Additionally, planned hot work activities in these fire zones should be minimized during the time within the extended TS Condition 3.8.1.A CT. In the event of an emergent issue requiring hot work in one of the listed zones, additional compensatory actions will be developed to minimize the risk of fire. The fire zones listed in Table 3.3-5 of Attachment 7 were identified based on risk significance in the FPRA results. Walkdowns are intended to reduce the likelihood of fires in certain zones by limiting transient combustibles, ensuring transients, if required to be present, be located away from fixed ignition sources, and eliminating or isolating potential transient ignition sources, (e.g., energized temporary equipment and associated cables). The following table identifies the risk-significant fire zones to which compensatory actions apply.

ATTACHMENT 6

COMPENSATORY MEASURES AND SUMMARY OF REGULATORY COMMITMENTS

Fire Zone(1)	Fire Zone Description
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room
5.2-1	Division 11 ESF Switchgear Room
5.2-2	Division 21 ESF Switchgear Room
2.1-0	Control Room
11.4C-0	Radwaste/Remote Shutdown Control Room
11.7-0	Auxiliary Building HVAC Exhaust Complex
11.6-0	Auxiliary Building General Area, 426' El.

ATTACHMENT 6

COMPENSATORY MEASURES AND SUMMARY OF REGULATORY COMMITMENTS

Summary of Regulatory Commitments

The following table identifies commitments made in this document. (Any other actions discussed in the submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.)

COMMITMENT	COMMITTED DATE OR "OUTAGE"	COMMITMENT TYPE	
		ONE-TIME ACTION (Yes/No)	Programmatic (Yes/No)
The Byron Station 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 Completion Time (CT).	During restoration of a required of a required qualified circuit in accordance with LCO 3.8.1, Required Action A.2 following a failure of System Auxiliary Transformer 242-1.	No	Yes
Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or LOOP will be avoided during the extended CT. In addition, no discretionary switchyard maintenance will be performed.	During restoration of a required of a required qualified circuit in accordance with LCO 3.8.1, Required Action A.2 following a failure of System Auxiliary Transformer 242-1.	No	Yes

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 7

BY-LAR-012, "RISK ASSESSMENT INPUT FOR THE BYRON ONE-TIME TECHNICAL SPECIFICATION CHANGE FOR CONDITION 3.8.1.A COMPLETION TIME FROM 72 HOURS TO 79 DAYS FOR UNITS 1 AND 2," DATED AUGUST 9, 2018

Exelon Generation.

Byron

PRA APPLICATION NOTEBOOK

BY-LAR-012

Risk Assessment Input for the Byron One-Time Technical Specification Change for Condition 3.8.1.A Extended Completion Time for Units 1 and 2

REVISION 1

TABLE OF CONTENTS

Revision Summary	Date	Info
0	August 2018	Original Issue
1	August 2018	Editorial changes

1.0 INTRODUCTION

1.1 PURPOSE

The purpose of this analysis is to assess the acceptability, from a risk perspective, of a change to extend the Byron Station completion time (CT) for Tech Spec Condition 3.8.1.A from 72 hours to 79 days for Units 1 and 2 in order to allow for replacement of the Unit 2 SATs. These proposed changes are requested to be effective only during a one-time extension.

The analysis follows the guidance provided in Regulatory Guide 1.200 Revision 2 [Ref. 1], "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities."

1.2 BACKGROUND

1.2.1 Technical Specification Changes

Since the mid-1980s, the NRC has been reviewing and granting improvements to TS that are based, at least in part, on probabilistic risk assessment (PRA) insights. In its final policy statement on TS improvements of July 22, 1993, the NRC stated that it . . .

> . . . expects that licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific PSA or risk survey and any available literature on risk insights and PSAs. . . Similarly, the NRC staff will also employ risk insights and PSAs in evaluating Technical Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements.

The NRC reiterated this point when it issued the revision to 10 CFR 50.36, "Technical Specifications," in July 1995. In August 1995, the NRC adopted a final policy statement on the use of PRA methods in nuclear regulatory activities that encouraged greater use of PRA to improve safety decision-making and regulatory efficiency. The PRA policy statement included the following points:

1. The use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.

2. PRA and associated analyses (e.g., sensitivity studies, uncertainty analyses, and importance measures) should be used in regulatory matters, where practical within the bounds of the state of the art, to reduce unnecessary conservatism associated with current regulatory requirements.

3. PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available for review.

4. The Commission's safety goals and subsidiary numerical objectives are to be used with consideration of uncertainties in making regulatory judgments...

The movement of the NRC to more risk-informed regulation has led to the NRC identifying Regulatory Guides and associated processes by which licensees can submit changes to the plant design basis including Technical Specifications. Regulatory Guides 1.174 [Ref. 2] and 1.177 [Ref. 3] both provide processes to incorporate PRA input for decision makers regarding a Technical Specification modification.

1.3 REGULATORY GUIDES

Three Regulatory Guides provide primary inputs to the evaluation of a Technical Specification change. Their relevance is discussed in this section.

1.3.1 Regulatory Guide 1.200, Revision 2

Regulatory Guide 1.200, Revision 2 [Ref. 1] describes an acceptable approach for determining whether the quality of the PRA, in total or the parts that are used to support an application, is sufficient to provide confidence in the results, such that the PRA can be used in regulatory decision-making for light-water reactors. This guidance is intended to be consistent with the NRC's PRA Policy Statement and more detailed guidance in Regulatory Guide 1.174.

It is noted that RG 1.200, Revision 2 endorses Addendum A of the ASME/ANS PRA Standard [Ref. 5] as clarified in Appendix A of RG 1.200, Revision 2.

1.3.2 Regulatory Guide 1.174, Revision 3

Regulatory Guide 1.174 [Ref. 2] specifies an approach and acceptance guidelines for use of PRA in risk informed activities. RG 1.174 outlines PRA related acceptance guidelines for use of PRA metrics of Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) for the evaluation of permanent TS changes. The guidelines given in RG 1.174 for determining what constitutes an acceptable permanent change specify that the ΔCDF and the ΔLERF associated with the change should be less than specified values, which are dependent on the baseline CDF and LERF, respectively.

RG 1.174 also specifies guidelines for consideration of external events. External events can be evaluated in either a qualitative or quantitative manner.

Since this LAR is for a one-time TS change, the ΔCDF and the ΔLERF of RG 1.1.74 do not specifically apply.

1.3.3 Regulatory Guide 1.177 Revision 1

Regulatory Guide 1.177 [Ref. 3] specifies an approach and acceptance guidelines for the evaluation of plant licensing basis changes. RG 1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed TS change as identified below:

- Tier 1 is an evaluation of the plant-specific risk associated with the proposed TS change, as shown by the change in core damage frequency (CDF) and incremental conditional core damage probability (ICCDP). Where applicable, containment performance should be evaluated on the basis of an analysis of large early release frequency (LERF) and incremental conditional large early release probability (ICLERP). The acceptance guidelines given in RG 1.177 for determining an acceptable permanent TS change is that the ICCDP and the ICLERP associated with the change should be less than 1E-06 and 1E-07, respectively. RG 1.177 also addresses risk metric requirements for one-time TS changes, as outlined in Section 1.3.4 of this risk assessment.

- Tier 2 identifies and evaluates, with respect to defense-in-depth, any potential risk-significant plant equipment outage configurations associated with the proposed change. The licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed TS change is out-of-service.

- Tier 3 provides for the establishment of an overall configuration risk management program (CRMP) and confirmation that its insights are incorporated into the decision-making process before taking equipment out-of-service prior to or during the CT. Compared with Tier 2, Tier 3 provides additional coverage based on any additional risk significant configurations that may be encountered during maintenance scheduling over extended periods of plant operation. Tier 3 guidance can be satisfied by the Maintenance Rule (10 CFR 50.65(a)(4)), which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance, testing, and corrective and preventive maintenance.

This risk analysis supports the Tier 1 element of RG 1.177, specifically the comparison of the results with the acceptance guidelines for ICCDP and ICLERP associated with changing a Technical Specification Completion Time. Other portions of the LAR submittal will address Tier 2 and Tier 3 elements.

1.3.4 <u>Acceptance Guidelines</u>

Risk significance in an LAR is determined by comparison of changes in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) and values of Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) produced by a <u>permanent</u> change to either the plant design basis or Technical Specifications to the guidelines given in Regulatory Guide 1.174 and Regulatory Guide 1.177. Reg. Guide 1.174 specifies the acceptable changes in CDF and LERF for <u>permanent</u> changes. Reg. Guide 1.177 specifies the acceptable ICCDP and ICLERP for <u>permanent</u> changes, usually associated with changing CT.

Reg. Guide 1.177 directly addresses the risk metric requirements for one-time TS changes, as reproduced below:

> *"For one-time only changes to TS CTs, the frequency of entry into the CT may be known, and the configuration of the plant SSCs may be established. Further, there is no permanent change to the plant CDF or LERF, and hence the risk guidelines of Regulatory Guide 1.174 cannot be applied directly. The following TS acceptance guidelines specific to one-time only CT changes are provided for evaluating the risk associated with the revised CT:*
>
> 1. *The licensee has demonstrated that implementation of the one-time only TS CT change impact on plant risk is acceptable (Tier 1):*
>   - *ICCDP of less than $1.0x10^{-6}$ and an ICLERP of less than $1.0x10^{-7}$,or*
>   - *ICCDP of less than $1.0x10^{-5}$ and an ICLERP of less than $1.0x10^{-6}$ with effective compensatory measures implemented to reduce the sources of increased risk.*
> 2. *The licensee has demonstrated that there are appropriate restrictions on dominant risk-significant configurations associated with the change (Tier 2).*
> 3. *The licensee has implemented a risk-informed plant configuration control program. The licensee has implemented procedures to utilize, maintain, and control such a program (Tier 3)."*

Based on the available quantitative guidelines for other risk-informed applications, it is judged that the quantitative criteria shown in Table 1-1 represent a reasonable set of acceptance guidelines. For the purposes of this evaluation, these guidelines demonstrate that the risk impacts are acceptably low. This combined with effective compensatory measures to maintain lower risk will ensure that the TS change meets the intent of small risk increases consistent with the Commission's Safety Goal Policy Statement.

Table 1-1
PROPOSED RISK ACCEPTANCE GUIDELINES

RISK ACCEPTANCE GUIDELINE	BASIS
ICCDP < 1E-6, or ICCDP < 1E-5 with effective compensatory measures implemented to reduce the sources of increased risk	ICCDP is an appropriate metric for assessing risk impacts of out of service equipment per RG 1.177. This guideline is specified in Section 2.4 of RG 1.177.

Table 1-1
PROPOSED RISK ACCEPTANCE GUIDELINES

RISK ACCEPTANCE GUIDELINE	BASIS
ICLERP < 1E-7, or ICLERP < 1E-6 with effective compensatory measures implemented to reduce the sources of increased risk	ICLERP is an appropriate metric for assessing risk impacts of out of service equipment per RG 1.177. This guideline is specified in Section 2.4 of RG 1.177.

1.4 SCOPE

This section addresses the requirements of RG 1.200, Revision 2 Section 3.1 which directs the licensee to define the treatment of the scope of risk contributors (i.e., internal initiating events, external initiating events, and modes of power operation at the time of the initiator). Discussion of these risk contributors are as follows:

- Full Power Internal Events (FPIE) – The Byron PRA model used for this analysis includes a full range of internal initiating events (including internal flooding) for at-power configurations. The FPIE model is further discussed in Section 1.5.

- Low Power Operation - The FPIE assessment is judged to adequately bound risk contributors associated with low power plant operations. The FPIE analysis assumes that the plant is at full power at the time of any internal events transient, manual shutdown, or accident initiating event. This analytic approach results in conservative accident progression timings and systemic success criteria compared to what may otherwise be applicable to an initiator occurring at low power. As such, low power risk impacts are not discussed further in this risk assessment.

- Shutdown / Refueling – Byron does not have a shutdown PRA model, but instead relies upon deterministic methodology to assess defense-in-depth of key safety functions. The intent is for the unit to remain at-power for the duration of the extended CT. Byron TS 3.8.2 has separate requirements associated with AC Power Sources when the unit is not online.

- Internal Fires – An Application-Specific Model (ASM) exists to support the submittal of Byron's TSTF-505 LAR for Risk-Informed Tech Specs and 50.69 LAR. This Fire ASM is further discussed in Section 3.3.

- Seismic - Byron does not currently maintain a Seismic PRA. An estimate of the seismic risk contribution using the 2013 re-evaluated Byron seismic hazard curve and information from the Byron IPEEE has been performed for this analysis (refer to Section 3.4.2).

- High Winds – Byron does not have a high winds PRA. A qualitative assessment is performed in this analysis (refer to Section 3.4.3).
- Other External Events - Other external event risks were assessed in the Byron IPEEE study [Ref. 13] and found to be insignificant risk contributors. These conclusions are revisited in this assessment (refer to Section 3.4.4).

1.5 BYRON PRA MODELS

This section addresses the requirements of Section 3.1 of RG 1.200, Revision 2 [Ref. 1] which directs the licensee to identify the portions of the PRA used in the analysis.

The PRA analysis uses the BB016a full power internal events (FPIE) Level 1 Core Damage Frequency (CDF) model and the associated Level 2 Large Early Release Frequency (LERF) model to calculate the risk metrics [Ref. 7]. The PRA analysis also uses the ASM fire model, BB-ASM-005 R0, which was developed to support the Byron 10CFR50.69 LAR [Ref. 10], to calculate the risk metrics for full power internal fires to develop quantitative and qualitative risk insights. Section 3.2 details the internal events analysis using the FPIE PRA, and Section 3.3 details the fire risk assessment.

2.0 ANALYSIS ROADMAP AND REPORT ORGANIZATION

The analysis and documentation utilizes the guidance provided in RG 1.200, Revision 2. The guidance in RG 1.200, Revision 2 indicates that the following steps should be followed to perform this study:

1. Per Section 3. of RG 1.200, include the following information regarding the PRA to support the application
   a. Describe the SSCs, operator actions, and operational characteristics affected by the application and how these are implemented in the PRA model.
   b. Provide a definition of the acceptance guidelines used for the application.
2. Per Section 3.1 of RG 1.200, identify the scope of risk contributors addressed by the PRA model
   a. If not full scope (i.e. internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Per Section 3.2 of RG 1.200, identify the parts of the PRA used to support the application
   a. Identify the logic model elements onto which the relevant SSCs, operator actions, and operational characteristics are mapped to the PRA model.
   b. Identify the relevant accident sequences that are impacted by the changes identified in the first group.
4. Per Section 3.3 and 4.2 of RG 1.200, demonstrate the Technical Adequacy of the PRA
   a. Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
   b. Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the Regulatory

Guide. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.

c. Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.

d. Identify key assumptions and approximations relevant to the results used in the decision-making process.

5. Per Section 4.2 of RG 1.200, summarize the risk assessment methodology used to assess the risk of the application

   a. Include how the PRA model was modified to appropriately model the risk impact of the change request.

Table 2-1 summarizes the RG 1.200 identified actions and the corresponding location of that analysis or information in this report.

Table 2-1

RG 1.200 ANALYSIS ACTIONS ROADMAP

RG 1.200 Actions	Report Section
1a. Describe the SSCs, operator actions, and operational characteristics affected by the application and how these are implemented in the PRA model.	Section 1.5 and Section 3.1.1
1b. Provide a definition of the acceptance guidelines used for the application.	Section 1.3.4
2. Identify the scope of risk contributors addressed by the PRA model.	Section 1.4
2a. If not full scope (i.e., internal and external events), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.	Section 3.3 and Section 3.4
3. Identify the parts of the PRA used to support the application	Section 1.5 and Section 3
3a. Identify logic model elements that are mapped to the PRA model	Section 3.1 and Section 3.2
3b. Identify the accident sequences impacted by those changes.	Section 3
4. Demonstrate the Technical Adequacy of the PRA.	Section 4
4a. Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.	Section 4.6.1, Table 4-1
4b. Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the RG. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.	Section 4.6.2, Table 4-2, and Table 4-3
4c. Document PRA peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.	Section 4.6.2 and Section 4.7
4d. Identify key assumptions and approximations relevant to the results used in the decision-making process.	Section 3.1 and Section 3.5 and Section 4.6.3
5. Summarize the risk assessment methodology used to assess the risk of the application. Include how the PRA model was modified to appropriately model the risk impact of the change request.	Section 1.5 and Section 3

3.0 RISK ANALYSIS

This section evaluates the plant-specific risk associated with the proposed TS change, based on the risk metrics of CDF, ICCDP, LERF, and ICLERP.

3.1 ASSESSMENT OVERVIEW AND ASSUMPTIONS

3.1.1 Overview

This analysis is performed for unavailability of SAT 242-1 and SAT 242-2. The PRA analysis involves identifying the system and components or maintenance activities modeled in the PRA which are most appropriate for use in representing the extended CT configurations and comparing the results to the baseline. Table 3.1-1 lists the base risk metrics for the FPIE PRA and the FPRA.

Table 3.1-1

BYRON CDF AND LERF BASE RISK METRICS

Risk	**BB016a - Unit 1 (/yr)**	**BB016a - Unit 2 (/yr)**
FPIE CDF	1.12E-5	1.08E-5
FPIE LERF	9.03E-7	8.99E-7
Risk Metric	**BB-ASM-005 R0- Unit 1 (/yr)**	**BB-ASM-005 R0 - Unit 2 (/yr)**
Fire CDF	5.61E-5	6.12E-5
Fire LERF	3.07E-6	3.07E-6

Plant auxiliary loads are powered by four 6.9kV and four 4160V buses in each unit. During normal operation the in-plant loads for Unit 2 are split between the UATs and SATs as shown in Table 3-1.

TABLE 3-1
NORMAL POWER SOURCES
FOR MAJOR AP BUSES

BUS	NORMAL FEED*
257, 243	UAT 241-1
256, 244	UAT 241-2
259, 241	SAT 242-1
258, 242	SAT 242-2

*Preferred normal configuration of power.

Two 4160V Class 1E (ESF) buses per unit provide power for safety related loads. The Unit 2, 4160V ESF buses are 241 and 242. The ESF power systems served by these buses are ESF Divisions 21 and 22 respectively. Three sources of power exist for each 4160V ESF bus: the normal feed from SATs 242-1 and 242-2, a reserve feed from Unit 1 Bus 141 or 142, and an emergency feed from EDGs 2A or 2B. Each analogous pair of 4160V ESF buses (141 and 241), (142 and 242), is connected by a tie line with two normally-open circuit breakers. The two tie line breakers are manually closed (in accordance with procedures) to provide reserve feed to an ESF division from the opposite unit. Each of the 4160V ESF buses has a dedicated EDG as a source of emergency power. The EDGs serving the two ESF divisions are numbered 2A and 2B.

The fault tree logic assumes that ESF Buses 241 and 242 are initially powered by the SAT prior to an accident sequence. The AP System portion(s) of the PRA model is constructed beginning with an assumed turbine trip at time zero, and is evaluated for a duration of time (typically 24 hr) after the turbine trip. The assumption of turbine trip is reasonable because the severe accident sequences to be modeled almost always involve reactor trip, and reactor trip initiates turbine trip. It is recognized that reactor trip may not always follow immediately after an IE.

The general configuration for the extended CT is Byron at-power on both units with both Unit 2 SATs out of service. The planned maintenance is expected to focus on replacing SAT 242-2 or SAT 242-1 within the requested extended CT. Concurrent maintenance work will be carefully managed during the extended CT. Section 5.4.1 discusses compensatory actions to support the plant condition associated with both Unit 2 SATs unavailable.

The PRA model was quantified using the base "average test and maintenance" PRA model with both Unit 2 SATs out for maintenance. The average test and maintenance model represents baseline assumed maintenance frequencies for all components with the exception of Technical Specification violations that are normally excluded in the disallowed maintenance logic in the base PRA model. Due to the relatively long time frame of the extension request, no specific maintenance terms are restricted in the quantification. In addition, the PRA Model of Record includes an assumption that a unit-to-unit crosstie of the ESF buses will be in place if both parts of the Unit 2 SAT are out-of-service (242-1 and 242-2). Since the proposed configuration does not implement the unit-to-unit crosstie, the PRA model is modified to remove that assumption by setting some gates to FALSE or by inserting logic to require the unit-crosstie alignment if necessary. Restricted maintenance and other assumptions are discussed further in Section 3.1.2. This configuration is represented in the PRA by setting specific flags as shown in Table 3.1-2.

In addition, refinements to how the fault tree models the Unit-to-Unit 4 kV ESF Bus Cross-ties were made to accurately reflect the abnormal configuration. The PRA model includes an assumption that when the U2 SATs (both SAT 242-1 and SAT 242-2) are out-of-service, the unit-crosstie (241-to-141 and/or 242-to-142) is already in place since a normal short-term SAT outage is expected to be treated that way. This unique long-term configuration assumes the Unit 2 SATs (both SAT 242-1 and SAT 242-2) are out-of-service without the unit-to-unit ESF Bus Cross-tie implemented, however, so model refinements removed that assumption because scenarios with EDG failure that require a unit-to-unit ESF Bus Cross-tie to restore power to 241 and/or 242 require an additional operator action. Specifically, operator action 0AP-XTIE-0-OA, "OPERATORS FAIL TO RESTORE DEAD ESF BUS VIA TIE LINE TO UNIT 2 ON LOOP," was added underneath the OR gates 2AP241-FROM-141, "BUS 141 FAILS TO PROVIDE POWER TO BUS 241

(VIA UNIT XTIE)," and 2AP242-FROM-142," BUS 142 FAILS TO PROVIDE POWER TO BUS 242 (VIA UNIT XTIE)."

Table 3.1-2

BOTH UNIT 2 SATS OOS EXTENDED CT CONFIGURATION REPRESENTATION

BASIC EVENT / GATE	DESCRIPTION	VALUE
2AP-BOTHSAT-TRMM	BOTH U2 SAT OOS FOR TM - 241 PWR VIA 141; 242 PWR VIA 142; 256 - 259 ON UAT(1)	TRUE
0AP-EITHERSAT	EITHER UNIT SAT OOS FOR TM	FALSE
1AP-CB1412-1414	FEED BREAKER 1412 OR 1414 TO BUS 141 FAILS TO OPEN WHEN FEEDING U2 BUSES	FALSE
1AP-CB1422-1424	FEED BREAKER 1422 OR 1424 TO BUS 142 FAILS TO OPEN WHEN FEEDING U2 BUSES	FALSE
2AP-CB2414-ALT	ALT SUPPLY CB 2414 FROM CROSSTIE FAILS TO OPEN WHEN POWERED FROM U1	FALSE
2AP-CB2424-ALT	ALT SUPPLY CB 2424 FROM CROSSTIE FAILS TO OPEN WHEN POWERED FROM U1	FALSE

Notes to Table 3.1-2:

(1) Description highlights assumptions associated with this individual basic event. Other inputs to the extended CT configuration establish that the cross-tie between Unit 1 and Unit 2 ESF buses is not in place.

3.1.2 Assumptions

The following assumptions are used in quantifying the plant risk due to both Unit 2 SATs OOS.

- Both Unit 2 SATs are assumed to be OOS (i.e., not limited by the current duration of 72 hours).
- The Unit 2 SATs are both flagged out for maintenance with the UATs supplying the ESF 4 kV buses fed through a cross-tie with the non-ESF kV buses.
- The Unit 1 to Unit 2 cross-tie between 4 kV ESF buses is not in place, but can be established by Ops if needed as a backup to the emergency diesel generators.

3.1.3 Quantification Truncation

The FPIE average maintenance model was quantified at truncations of 5E-11 and 1E-11 for CDF and LERF respectively based on a truncation test documented in the Quantification Notebook [Ref 8]. The FPRA average maintenance model was quantified at a truncation of 1E-12 and 1E-13 for CDF and LERF respectively based on a truncation test documented in the Fire ASM Notebook [Ref 7]. The same truncation levels used for this analysis are sufficient to provide a converged value of CDF or LERF. When decreasing these truncation levels by a decade, the respective results change by less than 5%.

3.1.4 Calculation Approach

The proposed technical specification change involves unavailability of both Unit 2 SATs. The revised CDF and LERF values for the CT configurations are obtained by re-quantifying the base PRA model with all of the identified events set as shown in Table 3.1-2. The BOTH-SATs Unit 2 maintenance term (2AP-BOTHSAT-TRMM) was set to TRUE using a flag file.

The evaluation of ICCDP and ICLERP for this condition is determined as shown below:

The ICCDP associated with both Unit 2 SATs OOS for a new CT is given by

$$ICCDP_{\text{Both Unit 2 SATs}} = (CDF_{\text{Both Unit 2 SATs}} - CDF_{BASE}) \times CT_{NEW} \qquad [Eq.\ 3\text{-}1]$$

where

$CDF_{\text{Both Unit 2 SATs}}$ = the annual average CDF calculated with both Unit 2 SATs OOS assuming the configuration listed in Table 3.1-2 (all quantified hazards)

CDF_{BASE} = baseline annual average CDF with average unavailability for all equipment. This is the CDF result of the baseline PRA (all quantified hazards)

CT_{NEW} = the new extended CT (in units of years)

Note: ICCDP is a dimensionless probability.

To calculate the maximum allowed CT_{NEW}, the formula can be rearranged to solve for CT_{NEW} with the ICCDP limit (and a conversion factor to produce the result in days):

$$CT_{NEW} = ICCDP_{Limit} / (CDF_{Both\ Unit\ 2\ SATs} - CDF_{BASE}) * 365\ \text{days/year} \qquad [\textit{Eq. 3-2}]$$

Risk significance relative to ICLERP is determined using equations of the same form as noted above for ICCDP.

Since this evaluation is for a one-time Tech Spec CT allowance, the ICCDP and ICLERP are the only meaningful metrics as there is no permanent change in plant risk after this one-time CT extension.

3.2 INTERNAL EVENTS

The relevant inputs from internal events (including internal flooding) to Equation 3-2 (and the equivalent for LERF) are shown in Tables 3.2-1 and 3.2-2 below.

Table 3.2-1
FPIE RISK ASSESSMENT INPUT PARAMETERS AND RESULTS FOR UNIT 1

Input Parameter	Value
CDF_{BASE}	1.12E-05/yr(1)
$CDF_{Both\ Unit\ 2\ SATs}$	1.29E-05/yr(1)
$LERF_{BASE}$	9.03E-07/yr(2)
$LERF_{Both\ Unit\ 2\ SATs}$	9.21E-07/yr(2)

(1) Based on a truncation of 5E-11

(2) Based on a truncation of 1E-11

Table 3.2-2
FPIE RISK ASSESSMENT
INPUT PARAMETERS AND
RESULTS FOR UNIT 2

Input Parameter	Value
CDF_{BASE}	1.08E-05/yr(1)
$CDF_{Both\ Unit\ 2\ SATs}$	4.41E-05/yr(1)
$LERF_{BASE}$	8.99E-07/yr(2)
$LERF_{Both\ Unit\ 2\ SATs}$	2.18E-06/yr(2)

(1) Based on a truncation of 5E-11

(2) Based on a truncation of 1E-11

In addition to the CDF/LERF calculations, a sequence review is performed as directed by ER-AA-600-1046 [Ref. 38]. This analysis consists of determining if significant changes to accident sequences exist due to the extended CT configuration. Since the limiting values occur for Unit 2 CDF, the sequence review focuses on Unit 2 and CDF.

As shown in Table 3.2-3, for both Unit 2 SATs OOS, a few transient sequences contribute to the most significant increases. With the SAT out-of-service, these sequences now act more like a Loss of Offsite Power instead of more simple transient events.

Table 3.2-3

UNIT 2 COMPARISON OF SEQUENCE CONTRIBUTIONS FOR BOTH UNIT 2 SATS OOS CASE

Sequence Group	Description	Both Unit 2 SATs OOS CDF	% Contribution to Case CDF	Base Case Contribution
2TRAN-04	Transient with failure of all feed to the Steam Generators and failure to establish ECCS high pressure recirculation cooling after successful high pressure injection via the charging pumps. The dominant initiating events associated with this sequence are Loss of SX and internal flooding scenarios. The key operator actions which contribute to this sequence are failure to restore feedwater from the main feedwater pumps and failure to establish the AFW cross-tie.	2.86E-05	64.8%	1.14E-06
2TRAN-09	This is a transient with failure of Auxiliary Feedwater, failure of Motor Driven and Startup Feedwater Pumps, and failure to establish Bleed and Feed using Charging Pumps and Safety Injection Pumps. The key initiating events associated with this sequence are Loss of SX and internal flooding. The SX pumps are the most risk significant components in this sequence. Operator actions which contribute to this sequence are failure to establish feedwater from the main feedwater system and failure to mitigate internal flooding events.	6.05E-06	13.7%	3.05E-07
2SLOC-09	Small LOCA with failure of High Pressure Injection via Charging Pumps and Safety Injection Pumps. This sequence is dominated by induced RCP Seal LOCAs, primarily from Loss of SX and internal flood initiators. Operator actions which contribute to this sequence are failure to open the SX crosstie valves, failure to align FP for CV pump cooling, and failure to isolate internal flood initiators. Dependent operator actions related to Loss of SX are key contributors.	3.59E-06	8.1%	3.24E-06
2SLOC-06	Small LOCA with failure to establish ECCS recirculation cooling and successful cooldown and depressurization. Most of this sequence is due to RCP Seal LOCAs following a Loss of CCW. The dominant operator action which contributes to this sequence is failure to align the CV pump to a cool suction source.	2.75E-06	6.2%	2.73E-06

Table 3.2-3

UNIT 2 COMPARISON OF SEQUENCE CONTRIBUTIONS FOR BOTH UNIT 2 SATS OOS CASE

Sequence Group	Description	Both Unit 2 SATs OOS CDF	% Contribution to Case CDF	Base Case Contribution
2SGTR-03	Steam Generator Tube Rupture with failure of shutdown cooling. Risk from this sequence is dominated by a variety of human actions to cooldown the RCS, throttle the SX007 valves, establish shutdown cooling, reduce ECCS injection, and stop the RH pumps while on miniflow.	1.92E-06	4.3%	3.63E-07
2TRAN-05	This is a transient with failure of Auxiliary Feedwater and failure of Motor Driven and Startup Feedwater Pumps. HPI is provided by the CCPs, but feed and bleed fails due to failure of the PORVs to open due to operator failure.	1.10E-06	2.5%	7.31E-07
2SLOC-02	Small LOCA with failure to establish ECCS recirculation cooling and successful cooldown and depressurization. Essentially all of this sequence is due to random non-isolable small LOCAs. Induced RCP Seal LOCAs are negligible contributors. The dominant operator action which contributes to this sequence is failure to secure the RH pumps in the mini-flow mode (resulting in their failure).	9.23E-07	2.1%	8.63E-07

Another characterization of the risk for this plant condition involves assessment of the initiating events that contribute to risk. Since the limiting values occur for Unit 2 CDF, the initiating event review focuses on Unit 2 and CDF. As shown in Table 3.2-4, these initiating events (which are treated in the transient sequences noted above) become more challenging due to the unavailability of the Unit 2 SAT. These results are consistent with the results of the sequence analysis.

The Loss of SX initiating event group captures failures of the SX system on Unit 2, and the Internal Flooding initiating event group captures internal flooding events, which tend to fail the SX pumps located in the basement of the Aux Building. These insights indicate that initiating events associated with failing SX become the biggest contributors to risk during the extended CT.

Table 3.2-4

UNIT 2 CDF CONTRIBUTION BY INITIATING EVENT GROUP

Initiating Event Group	Extended CT Configuration % Contribution	Base Case Contribution
Loss of SX	47%	23%
Internal Flooding	27%	15%
Transients	9%	9%
Loss of CC	7%	24%
SGTR	5%	5%
Loss of AP	3%	11%
Small LOCA	2%	7%
LOOP	1%	4%

In addition, the cutsets were reviewed and the Top 20 new cutsets resulting from the proposed LAR configuration are shown in Table 3.2-5.

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
1	7.54E-06	7.96E-06	0SX-ALL----CSRPGIE	SX STRAINERS - PLUGGED DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
2	3.88E-06	2.15E-04	0SX01AB2AB-CPMFRIE	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		1.91E-02	2AF01PB-----PDFR	DIESEL-DRIVEN PUMP 2AF01PB RANDOM FAILURE TO RUN
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
3	2.85E-06	2.15E-04	0SX01AB2AB-CPMFRIE	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		1.40E-02	2AF01PB-SX-HXVOA	OPERATORS FAIL TO SUPPLY DD AF PUMP WITH ALTERNATE SX COOLING
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
4	2.00E-06	2.15E-04	0SX01AB2AB-CPMFRIE	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		9.81E-03	2AF01PB-----PDFS	DIESEL-DRIVEN PUMP 2AF01PB RANDOM FAILURE TO START
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
5	1.56E-06	3.90E-04	%FL2SX-GA1SXPANA	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - SX PUMP A
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
6	1.56E-06	3.90E-04	%FL2SX-GA2SXPBNA	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - SX PUMP B
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
7	1.23E-06	2.15E-04	0SX01AB2AB-CPMFRIE	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		6.04E-03	2AF01PB-----PDMM	AF DIESEL-DRIVEN PUMP 2AF01PB UNAVAILABLE DUE TO MAINTENANCE
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
8	6.16E-07	5.86E-04	%FL2SX-GA0----T1	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		1.05E-03	2AP232X1----BSMM	MCC 232X1 UNAVAILABLE DUE TO MAINTENANCE
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
9	6.16E-07	5.86E-04	%FL2SX-GA0----T1	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		1.05E-03	1AP132X1----BSMM	MCC 132X1 UNAVAILABLE DUE TO MAINTENANCE
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
10	5.28E-07	1.32E-04	%FL2AF-GA0----T1	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM AUX FEEDWATER INTO AUX BLDG - COMMON ARE
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING
11	5.12E-07	4.88E-04	%RC-SGTR2-B-HXIE	STEAM GENERATOR TUBE RUPTURE IN S/G 2B
		1.05E-03	2AP231X2----BSMM	MCC 231X2 UNAVAILABLE DUE TO MAINTENANCE
12	5.12E-07	4.88E-04	%RC-SGTR2-C-HXIE	STEAM GENERATOR TUBE RUPTURE IN S/G 2C
		1.05E-03	2AP231X2----BSMM	MCC 231X2 UNAVAILABLE DUE TO MAINTENANCE
13	3.79E-07	9.47E-05	%FL2SX-MA0----T1	UNIT 2 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING
		1.00E+00	0SX-FLTMFT1HPMOA	FAILURE TO ISOLATE SX PIPE BREAK IN AUX BLDG (MF-T1)
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
14	2.54E-07	6.36E-05	%FL2SX-MA1SXPANA	UNIT 2 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - SX PUMP A
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
15	2.54E-07	6.36E-05	%FL2SX-MA2SXPBNA	UNIT 2 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - SX PUMP B
		4.00E-03	0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
16	2.49E-07	1.28E-04	%FL2SX-MA0----T2	UNIT 2 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		1.95E-03	0RX-JHEPF6-HOADA	JOINT HEP FOR FLOOD EVENTS 0FP-FP-CCP-HXVOA AND 0SX-FLTMFT2HPMOA (SX-MF-T2-C)
17	2.31E-07	5.86E-04	%FL2SX-GA0----T1	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		7.89E-04	1AP142------BSOM	4.16KV ESF BUS 142 IS UNAVAILABLE DUE TO MAINTENANCE AT ALL MODES
		5.00E-01	FLAG-CCHTX0-U1	CCW HTX 0 ALIGNED TO UNIT 1
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
18	2.31E-07	5.86E-04	%FL2SX-GA0----T1	UNIT 2 GENERAL FLOOD (100-2000GPM) FROM SX INTO AUX BLDG - COMMON AREA

Table 3.2-5

UNIT 2 TOP 20 CDF NEW CUTSETS FOR BOTH UNIT 2 SATS OOS CONFIGURATION

Cutset #	Cutset Prob.	Event Prob	Event	Event Description
		7.89E-04	1AP141------BSOM	4.16KV ESF BUS 141 IS UNAVAILABLE DUE TO MAINTENANCE AT ALL MODES
		5.00E-01	FLAG-CCHTX0-U1	CCW HTX 0 ALIGNED TO UNIT 1
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
19	1.40E-07	2.15E-04	0SX01AB2AB-CPMFRIE	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)
		9.47E-01	%SXIE	INDICATOR FOR SX INITIATING EVENT
		6.90E-04	2AF01PB-FO-HXVOA	OPERATORS FAIL TO REFILL DDAFP FUEL OIL DAY TANK FROM STORAGE TANK
		1.00E+00	FLAG-SX-FAILS-U1	FLAG EVENT - TOTAL LOSS OF UNIT 1 SX
		1.00E+00	FLAG-SX-FAILS-U2	FLAG EVENT - TOTAL LOSS OF UNIT 2 SX
		1.00E+00	FLAG-SX-IE	DUMMY FLAG TO PREVENT NON-IE CUTSETS FROM PROPAGATING
20	1.34E-07	1.28E-04	%FL2SX-MA0----T2	UNIT 2 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - COMMON AREA
		1.05E-03	1AP132X1----BSMM	MCC 132X1 UNAVAILABLE DUE TO MAINTENANCE

The new cutsets are transient accident sequences. With the unavailability of the Unit 2 SAT, restoration of main feedwater is not available since the non-ESF buses are not powered, so a loss of auxiliary feedwater (either directly or due to loss of service water (SX)) leads to a loss of secondary cooling capability. These sequences then require a transition to feed-and-bleed, which is failed due to the loss of service water (either directly or due to flood effects)

Table 3.2-6 lists the most risk-significant Operator Actions from the configuration case results.

Table 3.2-6

UNIT 2 SIGNIFICANT OPERATOR ACTIONS FROM CUTSET REVIEWS

Basic Event	Description
0FP-FP-CCP-HXVOA	OPERATOR FAILS TO ALIGN FP CCP COOLING UPON LOSS OF SX DUE TO NON-FP FLOODING per 0BOA PRI-8 "Aux Building Flooding Unit 0" and 2BOA PRI-7 "Essential Service Water Malfunction"
2AF01PB-SX-HXVOA	OPERATORS FAIL TO SUPPLY DD AF PUMP WITH ALTERNATE SX COOLING per 0BOA PRI-7 "Loss of Ultimate Heat Sink"

Operating Crew briefings to identify and review these actions for the duration of the extended CT would be prudent. Each shift, operators should brief on the following actions:

- Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
- Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
- Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate SX cooling
- Aligning fire protection cooling to centrifugal charging pumps, 2CV01PA and 2CV01PB, upon loss of SX
- Locally failing air to the Unit 2 AF005 valves on loss of main feedwater
- BOP DG-22, Diesel Generator Operation after Auto Start
- 2BOA ELEC-4, Loss of Offsite Power Unit 2

- 2BEP ES-0.1, Reactor Trip Response Unit 2 actions concerning natural circulation cooldown
- BOP DO-16, Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank, (U2)
- BOP CC-10, Alignment of the U-0 CC Pump and U-0 CC HX to a Unit

Table 3.2-7 provides a review of basic event Fussell-Vesely (FV) importance for the case of both Unit 2 SATs unavailable. This table shows basic events with more than 1% contribution to CDF. This table excludes FLAG events, alignment events, initiating events, and human failure events.

Table 3.2-7

UNIT 2 BASIC EVENTS WITH GREATER THAN 1% CDF CONTRIBUTION

Event	Description	FV - CDF
2AF01PB-----PDFR	DIESEL-DRIVEN PUMP 2AF01PB RANDOM FAILURE TO RUN	14%
2AF01PB-----PDFS	DIESEL-DRIVEN PUMP 2AF01PB RANDOM FAILURE TO START	7%
2AF01PB-----PDMM	AF DIESEL-DRIVEN PUMP 2AF01PB UNAVAILABLE DUE TO MAINTENANCE	4%
SEAL-U2-TRANS	UNIT 2 SEAL LOCA >21GPM RANDOMLY OCCURS - NON-LOOP SEQUENCES	4%
2AP231X2----BSMM	MCC 231X2 UNAVAILABLE DUE TO MAINTENANCE	2%
2AF01PA-----PMMM	AF MOTOR-DRIVEN PUMP 2AF01PA UNAVAILABLE DUE TO MAINTENANCE	2%
2AP232X1----BSMM	MCC 232X1 UNAVAILABLE DUE TO MAINTENANCE	2%
1AP132X1----BSMM	MCC 132X1 UNAVAILABLE DUE TO MAINTENANCE	2%
0FP-UNAVAIL-TOCV	FP BREAK MAKES FP UNAVAILABLE TO SUPPLY CV COOLING	2%
2DG2A-------DGMM	DIESEL GENERATOR 2A UNAVAILABLE DUE TO MAINTENANCE AT POWER	1%
2DG2A-------DGFR	DG 2A FAILS TO RUN	1%
2AF01PA-B--CPMFR	AF PUMPS FAIL TO RUN DUE TO CCF (2/2)	1%

Notably, basic events associated with 2AF01PB, the diesel-driven AF pump, are the most significant contributors to CDF. In addition, maintenance basic events for electrical components make up some of the other top contributions to CDF. From this review, the following compensatory actions to mitigate risk are identified for the duration of the CT extension:

- Protect the following components
  - 2AF01PB
  - All four diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB
- Limit maintenance unavailability on the following components
  - 2AF01PB, Unit 2 diesel driven AF pump
  - 2AF01PA, Unit 2 motor driven AF pump
  - 2DG01KA, Unit 2 Diesel Generator A
  - 2DG01KB, Unit 2 Diesel Generator B
  - 2AP231X2, MCC 231X2
  - 2AP232X1, MCC 232X1
  - 1AP132X1, MCC132X1

<u>Compensatory Action Summary from the FPIE PRA Evaluation</u>

The following compensatory actions have been identified through review of the FPIE PRA results and are summarized below:

- Each shift, operators should brief on the following actions:
  - Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
  - Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
  - Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate SX cooling
  - Aligning fire protection cooling to centrifugal charging pumps, 2CV01PA and 2CV01PB, upon loss of SX
  - Locally failing air to the Unit 2 AF005 valves on loss of main feedwater
  - BOP DG-22, Diesel Generator Operation after Auto Start

    - 2BOA ELEC-4, Loss of Offsite Power Unit 2
    - 2BEP ES-0.1, Reactor Trip Response Unit 2 actions concerning natural circulation cooldown
    - BOP DO-16, Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank, (U2)
    - BOP CC-10, Alignment of the U-0 CC Pump and U-0 CC HX to a Unit

- Protect the following components
    - 2AF01PB
    - All four diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB

- Limit maintenance unavailability on the following components
    - 2AF01PB, Unit 2 diesel driven AF pump
    - 2AF01PA, Unit 2 motor driven AF pump
    - 2DG01KA, Unit 2 Diesel Generator A
    - 2DG01KB, Unit 2 Diesel Generator B
    - 2AP231X2, MCC 231X2
    - 2AP232X1, MCC 232X1
    - 1AP132X1, MCC132X1

3.3 INTERNAL FIRES

The Byron Fire PRA Application-Specific Model (ASM) that was developed for the 10 CFR 50.69 and TSTF-505 LAR is used for this LAR. BB-ASM-005 R0, "Application-Specific Model," provides details of the PRA model changes incorporated in the Fire PRA model to support closure of Findings and Observations (F&Os) from the February 2017 F&O closure review. Finalized in June 2017, the Byron and Byron Fire ASM BB011b model has the level of technical rigor to support the LAR for Risk-Informed Tech Specs, making it an appropriate model to generate Fire PRA risk metrics to support this application. [Ref 7]

The same process in Section 3.2 that was used for the FPIE model has also been used with the FPRA model results. The basic event changes for the equipment configuration during the extended CT are as shown in Table 3.1-2 for both Unit 2 SATs OOS. The relevant inputs to Equation 3-1 are shown in Tables 3.3-1 and 3.3-2 below. The corresponding output parameters from the equation above are then provided in Tables 3.3-3 and 3.3-4. Note that equations apply to fire LERF as well and the relevant inputs are also shown in Tables 3.3-1 and 3.3-2 with the output parameters provided in Tables 3.3-3 and 3.3-4.

The fire risk insights and compensatory measures are focused on CDF since the results indicate that the impact on fire CDF risk measures is more significant than that associated with the impact on fire LERF risk. ICCDP due to fire does not quantitatively credit implementation of any compensatory measures.

Table 3.3-1
UNIT 1 FIRE RISK ASSESSMENT
INPUT PARAMETERS

Input Parameter	Value
$FCDF_{BASE}$	5.39E-05/yr[1]
$FCDF_{BOTH\ Unit\ 2\ SATs}$	5.51E-05/yr[1]
$FLERF_{BASE}$	2.98E-06/yr[1]
$FLERF_{BOTH\ Unit\ 2\ SATs}$	3.03E-06/yr[1]

[1]Based on a truncation of 1E-12 for CDF and 1E-13 for LERF. These values do not match those in Table 3.1-1 because they incorporate refinement of fires scenarios in the Turbine Building and fires at the U2 SATs to more realistically model fire risk in the extended CT configuration.

Table 3.3-2

UNIT 2 FIRE RISK ASSESSMENT

INPUT PARAMETERS

Input Parameter	Value
$FCDF_{BASE}$	5.87E-05/yr[1]
$FCDF_{BOTH\ Unit\ 2\ SATs}$	7.21E-05/yr[1]
$FLERF_{BASE}$	2.99E-06/yr[1]
$FLERF_{BOTH\ Unit\ 2\ SATs}$	5.03E-06/yr[1]

[1]Based on a truncation of 1E-12 for CDF and 1E-13 for LERF. These values do not match those in Table 3.1-1 because they incorporate refinement of fires scenarios in the Turbine Building and fires at the U2 SATs to more realistically model fire risk in the extended CT configuration.

Significant Fire Zones and Compensatory Measures

The fire CDF results from the Unit 2 SATs OOS case identified the fire zones that could result in an increased likelihood of core damage. The fire zones with a contribution of greater than 1% of fire risk are listed in Table 3.3-3. These fire zones would potentially benefit from additional compensatory measures that could further reduce the risk of fires in these zones.

Table 3.3-3

UNIT 2 FIRE CDF BOTH UNIT 2 SATS OOS SIGNIFICANT FIRE ZONES

Fire Zone	Fire Zone Description	Unit 2 Importance Contribution
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure	12%
2.1-0	Control Room	12%
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room	9%
5.2-1	Division 11 ESF Switchgear Room	9%
5.2-2	Division 21 ESF Switchgear Room	8%
11.4C-0	Radwaste/Remote Shutdown Control Room	5%
11.7-0	Auxiliary Building HVAC Exhaust Complex	5%
11.6-0	Auxiliary Building General Area, 426' El.	5%
18.3-2	Unit 2 Main Steam/AFW Pipe Tunnel	3%

Table 3.3-3

UNIT 2 FIRE CDF BOTH UNIT 2 SATS OOS SIGNIFICANT FIRE ZONES

Fire Zone	Fire Zone Description	Unit 2 Importance Contribution
8.6-0	Turbine Building Operating Floor	2%
5.6-2	Division 21 Miscellaneous Electrical Equipment and Battery Room	2%
5.5-2	Unit 2 Auxiliary Electrical Equipment Room	2%
11.5-0	Auxiliary Building General Area, 401' El.	2%
11.4-0	Auxiliary Building General Area, 383" El.	1%
11.4A-2	Unit 2 Auxiliary Feedwater Pump 2B Room	1%
8.4-2	Unit 2 Auxiliary Boiler Room	1%
8.5-2	Unit 2 Turbine Building Mezzanine Floor	1%

As part of the Byron Configuration Risk Management Program (CRMP), Risk Management Actions (RMAs) were identified to reduce the fire risk when equipment with an appreciable impact on core damage mitigation is taken out-of-service. The CRMP includes RMAs for when both Unit 2 SATs are OOS for longer than 48 hours, which are documented in BY-CRM-117, Revision 1 [Ref 11]. For fire zones with high contribution, as specified in Table 3.3-5, the following RMAs are recommended:

- Maintain detection and suppression systems
- Minimize transient combustibles
- Limit location of transient combustibles to locations away from fixed ignition sources
- Maintain fire zone barriers
- Prohibit hot work and temporary heat/ignition sources (cables/equipment)

Significant Operator Actions and Compensatory Measures

The fire CDF results from the case with both Unit 2 SATs OOS identified the operator actions, if failed, that could result in an increased likelihood of core damage. The operator actions with the greatest contribution are listed in Tables 3.3-4.

Table 3.3-4

UNIT 2 FIRE CDF BOTH UNIT 2 SATS OOS SIGNIFICANT OPERATOR ACTIONS

Operator Action	Description	Contribution
0AP-XTIE-0-HHBOA-F	OPERATORS FAIL TO RESTORE DEAD ESF BUS VIA TIE LINE TO UNIT 2 ON LOOP per 2BOA ELEC-3 "Loss of 4 kV ESF Bus"	6.0%
SATCOMBO-31-2 (Joint HEP)	0AP-XTIE-0-HHBOA-F, 2AF-AF005--HAVOA-F (OPERATORS FAIL TO OPEN AF005 VALVES (LOCALLY FAIL AIR – FIRE) per 2BOA ELEC-2 "Loss of Instrument Bus"	4.6%
2AF01PB-FO-HXVOA-F	OPERATORS FAIL TO REFILL DDAFP FUEL OIL DAY TANK FROM STORAGE TANK – FIRE per 2BOP DO-13 "Filling the Unit 2 Diesel AF Pump Day Tank from the 125,000 or 50,000 Gallon Fuel Oil Storage Tanks"	3.6%
0SX-MU-TR--HMVRA-F	FAILURE TO RECOVER MAKEUP CAPABILITY BEFORE INVENTORY IS LOW (TRANS) per BAR 0-37-A8 "SX Cooling Tower Basin Level High Low" and BOP SX-12 "Makeup to an Essential Service Water Mechanical Draft Cooling Tower Basin"	3.3%

Operator briefings on the importance of these actions is suggested prior to entering the extended CT period.

Summary of Compensatory Measure Impacts on Important Fire Zones

Based on a review of results from the fire PRA contributors, the following compensatory actions are highlighted as important to reduce the risk from fire events during the performance of the extended TS Condition 3.8.1.A CT:

- Risk Management Actions (RMAs) applicable for this extended CT window will be completed per OP-AA-201-012-1001 "OPERATIONS ON-LINE FIRE RISK MANAGEMENT" (these actions protect against fire impacting key redundant equipment).

- Prior to entering the TS 3.8.1.A Action Statement for repair of Unit 2 SATs, an operating crew shift briefing and pre-job walkdowns are suggested to be conducted to reduce and manage transient combustibles and to alert the staff about the increased sensitivity to fires in the fire zones specified in Table 3.3-5. Operating crew shift briefings will continue to be conducted every shift throughout the duration of the CT period. Additionally, planned hot work activities in these fire zones should be minimized during the time within the extended TS Condition

3.8.1.A CT. In the event of an emergent issue requiring hot work in one of the listed zones, additional compensatory actions will be developed to minimize the risk of fire. The fire zones listed in Table 3.3-5 were identified based on risk significance in the FPRA results. Walkdowns are intended to reduce the likelihood of fires in certain zones by limiting transient combustibles, ensuring transients, if required to be present, be located away from fixed ignition sources, and eliminating or isolating potential transient ignition sources, e.g., energized temporary equipment and associated cables.

Table 3.3-5

RISK-SIGNIFICANT FIRE ZONES TO WHICH COMPENSATORY ACTIONS APPLY

Fire Zone	Fire Zone Description
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room
5.2-1	Division 11 ESF Switchgear Room
5.2-2	Division 21 ESF Switchgear Room
2.1-0	Control Room
11.4C-0	Radwaste/Remote Shutdown Control Room
11.7-0	Auxiliary Building HVAC Exhaust Complex
11.6-0	Auxiliary Building General Area, 426' El.

- Aside from the period of aligning UAT-to-ESF bus supply, maintain SAT supply feed breakers to ESF buses, 2412 and 2422, racked out
  - This Compensatory Measure is explicitly credited in the fire risk quantification
- Aside from the period of aligning UAT-to-ESF bus supply, open test switches for breakers 2412/2422 to prevent lockout relays from impacting breakers 2413 and 2414/2423 and 2424 operation
  - This Compensatory Measure is explicitly credited in the fire risk quantification

The Fire PRA risk for both Unit 2 SATs OOS condition discussed in this section will be reduced below reported values through implementation of these additional controls.

3.4 EXTERNAL EVENTS

3.4.1 Assessment of Relevant Hazard Groups

The purpose of this portion of the assessment is to evaluate the spectrum of external event challenges to determine which external event hazards should be explicitly addressed as part of the Condition 3.8.1.A extension risk assessment.

Internal events, including internal flooding, and internal fires are quantitatively addressed as described in the previous sections.

The impact due to seismic, high winds, external floods, and other hazard groups are addressed here. It is noted that it is unnecessary to evaluate the low-power and shutdown contribution to the base CDF and LERF since the change being proposed involves performance of the repair while at-power. Tech Spec Condition 3.8.1.A applies to Modes 1-4. The PRA models used for this application incorporate assumptions that apply to Modes 1-3. Thermal hydraulic conditions associated with Mode 4 allow more time to respond to transient events and more margin to meet success criteria, so Mode 4 risk is bounded by the risk analyses for at-power conditions. For Modes 5 and 6, a different Tech Spec Condition, TS 3.8.2, outlines the conditions and requirements associated with AC power sources, which precludes Modes 5 and 6 from the scope of this application. Additionally, OU-AP-104, "Shutdown Risk Management," provides guidance for configuration risk management in Modes 4-6 based on defense-in-depth considerations. This section presents the analysis that estimates the potential seismic impact for inclusion in the decision-making process, as a seismic PRA is not available for Byron Nuclear Generating Station.

3.4.2 Seismic

The configuration of the SATs is only significant to plant seismic risk with offsite power available, since the SATs are not being used in an alignment that makes them part of the emergency power supply (i.e., via EDGs). As a result, the seismic ICCDP and ICLERP result only from the portion of the seismic hazard up to the g-level that results in loss of offsite power. Above this level, the seismic CDF (or LERF) for the SAT OOS configuration is the same as for the base configuration, so there is no delta seismic risk.

The high confidence of low probability of failure (HCLPF) for offsite power is estimated as 0.1g, assuming failure of components such as ceramic insulators in the offsite power switchyard, based on the fragility data from Table 4B-1 of the RASP Handbook [Ref. 57]. As a result, the delta risk impact of seismic events associated with the SATs is only associated with the portion of the seismic hazard curve below the level at which seismic-induced LOOP would be expected (0.1g).

The Byron IPEEE assessed Byron structures, systems and components (SSCs) associated with Byron seismic margin assessment (SMA) success paths to a review level earthquake (RLE) value of 0.3g. The Byron IPEEE established that all SSCs on the success path component list (SPCL) have a median capacity of at least 0.3g PGA or are acceptable as-is. A recent evaluation of the as-built, as-operated plant has been performed against the SMA SPCL to establish the continued applicability of the SMA. The evaluation was a comparison of the as-built, as-operated plant to the plant configuration originally assessed by the SMA. Differences were reviewed to confirm that the SPCL continues to reflect the as-operated plant. This confirms that the plant has substantial seismic capacity over the hazard range of interest for this evaluation and supports an assumption that there will be no significant seismic impact on plant transient response in this range, such that insights can be drawn without a seismic PRA. Therefore, it is assumed that a seismic event of magnitude less than the g-level at which a LOOP is likely will result in a plant transient with the same CCDP and CLERP values as those from a random plant transient.

The approach is then to calculate the seismically-induced transient SCDF and SLERF for cases with and without SATs for both units, from above the operational basis earthquake (OBE) level to the level at which offsite power would likely be lost. Use of the OBE is an appropriate lower bound for g-level since the plant would not be expected to experience a significant transient below this level and would be able to continue operating. The BY OBE is approximately 0.09g [Ref. 45]. Since this is very close to the 0.1g LOOP HCLPF, a broader range of potential seismic impact should be considered. Therefore, the lower bound for this evaluation is conservatively taken as 0.01g. The seismic frequency in this range is obtained using the Byron 2013 re-evaluated seismic hazard [Ref. 46], and is the difference between the mean exceedance frequency at 0.01g (5.45E-03/yr) and the mean exceedance frequency at 0.1g (2.26E-04/yr), or 5.2E-3 events/yr. The CCDP (and CLERP) is obtained for the CT configuration and for the Base configuration for a general transient initiating event using the FPIE model. The difference between the CT configuration and Base configuration is the seismic delta CCDP (and delta CLERP) contribution to be used in the determination of the allowable CT.

The PRA model was quantified using i) the Base configuration and ii) the base "average test and maintenance" PRA model with both Unit 2 SATs out for maintenance. In addition, general transient initiating events (%FW-GTR-1---HWIE and %FW-GTR-2---HWIE) were set to 1.0 and all the other initiators to false for both models; this provides general transient CCDP and CLERP values for both the Base configuration model and the model with both Unit 2 SATs out for maintenance. Results are summarized in Table 3.4-1 for both cases with and without the SATs for both units.

Table 3.4-1

UNIT 1 AND UNIT 2 CCDP AND CLERP VALUES FOR W/ AND W/O SAT CASES

	CCDP U1	CCDP U2	CLERP U1	CLERP U2
w/ SATs	5.43E-07	4.69E-07	1.47E-08	1.45E-08
w/o SATs	5.44E-07	4.52E-06	1.47E-08	1.28E-07
Delta CCDP (CLERP)	1.0E-09	4.1E-06	Insignificant	1.1E-07

The seismic frequency in the 0.01g to 0.1g range (5.2E-03) is then multiplied by the difference between the CCDP (CLERP), i.e., the difference with and without SAT 242 available, from Table 3.4-1 to estimate the delta seismic risk. As can be seen from Table

3.4-1, the results for Unit 2 are limiting. The seismic delta-CDF for Unit 2 is (4.1E-06 x 5.2E-03) = 2.1E-08/yr.

The above assessment is based on the HCLPF for LOOP, meaning that at 0.1g there is an approximately 1% probability that a LOOP occurs. To address the fact that LOOP might not occur at this hazard level, in which case the SATs would still be relevant to the seismic delta-risk, a sensitivity has been performed for Unit 2 to assess the impact of extending the hazard frequency. For this sensitivity, rather than adjusting the LOOP g-level to a higher value, the incremental seismic frequency is simply taken as the exceedance frequency at 0.01g, i.e., 5.45E-03/yr, effectively encompassing almost the entire seismic hazard. Note that, in both the base and sensitivity cases, an additional significant conservatism is introduced by the fact that the entire annual seismic hazard is considered, whereas the eventual extended CT will be less than one year.

Table 3.4-2 provides the results of the estimated delta SCDF and SLERF for the base case and the sensitivity case for Unit 2. The results of the sensitivity case will be used for the CT calculation in Section 3.5.

Table 3.4-2

UNIT 2 LOOP CCDP AND CLERP VALUES FOR W/ AND W/O SAT CASES

Applicable Seismic Frequency Range	Delta CDF U2	Delta LERF U2
Base Case: 5.2E-3/yr	2.1E-08	5.9E-10
Sensitivity Case: 5.5E-3/yr	2.2E-08	6.2E-10

3.4.2.1 Conclusion of Seismic Impact

The evaluation of seismic risk impact due to the proposed extended SAT CT indicates that, even with conservative assumptions, the incremental seismic risk is small. The estimated impacts are included in the overall CT calculation in Section 3.5.

3.4.3 High Winds

Byron station does not have a high winds PRA model. The impact of the proposed completion time extension will be addressed qualitatively for high winds hazards.

During a tornado event, it is very likely that offsite power will be lost, due to tornado wind or missile damage of switchyard components and/or the electrical power lines and towers between the switchyard, the auxiliary transformers, and the electrical switchgear [55]. The SATs and UATs are co-located on the Byron site (e.g., UAT 241-2 is less than 40 feet from SAT 242-1 [56]); electrical power lines between the switchyard and the transformers are also co-located. Therefore, it is highly probable that if power is lost to either a Unit 2 UAT or Unit 2 SAT during a tornado event, power will be lost to all Unit 2 UATs and SATs. Likewise, if a Unit 2 SAT remains energized following a tornado event, it is very likely that Unit 2 UATs would also remain energized.

The risk impact of the proposed electrical configuration, due to high wind hazards, is from a potential change in the loss of offsite power probability. The loss of offsite power probability during a high wind event is already high, and there is a negligible difference in the probability of loss of offsite power to the ESF buses during a tornado or other high wind event, whether the ESF buses are powered by SATs or UATs. Therefore, the change in CDF and LERF for Unit 2 are negligible, and the Unit 2 ICCDP and ICLERP due to high winds are much less than 1E-6 and 1E-7, respectively.

With the Unit 2 SATs unavailable, there is a low likelihood high winds scenario that can impact Unit 1 CDF. In the event that a high winds event causes a Unit 1 LOOP but not a Unit 2 LOOP, the Unit 2 SATs would not be available to provide power to Unit 1 through the crosstie. This scenario is reflected in the Unit 1 internal events results provided in Section 3.2.

If both units lose offsite power during the high winds event, there is no change to the Unit 1 risk in the proposed configuration. The probability that only a single unit is affected by a high winds event is unknown, since there is insufficient data available to determine a value. However, it is expected that only a small percentage of high winds events only cause a single unit LOOP as opposed to a dual Unit LOOP, especially for the higher intensity events. Due to the relatively low likelihood of such an event, compared to the single unit LOOP events included in the internal events results, the risk increase to Unit 1 from high winds is judged to be insignificant.

3.4.4 <u>Other External Hazards Evaluation and Conclusions</u>

A plant-specific evaluation of an extensive set of other external hazards was performed for the Individual Plant Evaluation of External Events (IPEEE) in response to GL 88-20 [Ref 13] for evaluation of the following other external hazards:

- External Flooding
- Transportation and Nearby Facility Accidents
- Other External Initiating Events

That evaluation has been updated using the criteria in ASME PRA Standard RA-Sa-2009 [Ref. 28], and concluded that all other external hazards can be screened from applicability to Byron Station Units 1 and 2.

Therefore, there is no significant other external hazards risk contribution for this application.

Attachment 1 provides a summary of the other external hazards screening results.

Attachment 2 provides a summary of the progressive screening approach for external hazards.

3.5 RESULTS COMPARISON TO ACCEPTANCE GUIDELINES

Tables 3.5-1 and 3.5-2 show a comparison of the individual hazard group core damage risk metrics to the acceptance guidelines defined in Section 1.3.4.

Table 3.5-1

Unit 1 COMPARISON OF INDIVIDUAL HAZARD GROUP RESULTS TO ACCEPTANCE GUIDELINES

	DELTA CDF	DELTA LERF
Internal Events and Internal Floods	1.8E-06	1.8E-08
Internal Fires	1.2E-06	5.0E-08
Seismic	Negligible	Negligible
Other Hazard Groups	Negligible	Negligible
Total Values	3.0E-06	6.8E-08
Acceptance Guideline	Total ICDP = 1.0E-05[(1)]	Total ICLERP = 1.0E-06[(2)]
Time to reach Acceptance Guideline	> 1 year	> 1 year

[(1)] Per RG 1.177 a value between 1E-06 and 1E-05 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

[(2)] Per RG 1.177 a value between 1E-07 and 1E-06 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

Table 3.5-2

Unit 2 COMPARISON OF INDIVIDUAL HAZARD GROUP RESULTS TO ACCEPTANCE GUIDELINES

	DELTA CDF	DELTA LERF
Internal Events and Internal Floods	3.3E-05	1.3E-06
Internal Fires	1.3E-05	1.9E-06
Seismic	2.2E-08	6.2E-10
Other Hazard Groups	Negligible	Negligible
Total Values	4.6E-05	3.2E-6
Acceptance Guideline	Total ICDP = 1.0E-05[(1)]	Total ICLERP = 1.0E-06[(2)]
Time to reach Acceptance Guideline	> 79 days	> 114 days

[(1)] Per RG 1.177 a value between 1E-06 and 1E-05 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

[(2)] Per RG 1.177 a value between 1E-07 and 1E-06 may be deemed acceptable with effective compensatory measures implemented to reduce the sources of increased risk.

The results indicate a one-time extension up to 79 days would not exceed the ICCDP and ICLERP risk limits. Additional compensatory measures would potentially reduce risk further, such as protected equipment and heightened awareness of important operator actions and high risk fire zones. Except for where explicitly noted, the additional compensatory measures are not accounted for in the quantification.

3.6 UNCERTAINTY ASSESSMENT

The purpose of this section is to disposition the impact of Probabilistic Risk Assessment (PRA) modeling epistemic uncertainty for Condition 3.8.1.A CT extension assessment. The baseline internal events PRA (including internal flood) and fire PRA (FPRA) models document assumptions and sources of uncertainty and these were reviewed during the model peer reviews. The approach taken is, therefore, to review these documents to identify the items which may be directly relevant to Condition 3.8.1.A CT extension assessment, discuss the results, and to provide dispositions for the Condition 3.8.1.A CT extension assessment.

The epistemic uncertainty analysis approach described below applies to the internal events PRA and any epistemic uncertainty impacts that are unique to FPRA are also addressed.

3.6.1 Assessment of Internal Events PRA Epistemic Uncertainty Impacts

In order to identify key sources of uncertainty for the referenced Condition 3.8.1.A CT extension assessment, the uncertainties identified in the internal events baseline PRA model uncertainty report [Ref 16] (based on the guidance in NUREG-1855 [Ref 17] and EPRI 1016737 [Ref 18]) were evaluated within the context of this application. As described in NUREG-1855, sources of uncertainty include "parametric" uncertainties, "modeling" uncertainties, and "completeness" (or scope and level of detail) uncertainties.

Parametric uncertainty was addressed as part of the Byron and Braidwood Generating Stations (BY/BW) baseline PRA model quantification [Ref 8]. No specific impact is expected on the results of this application.

Modeling uncertainties are considered in both the base PRA and in specific risk-informed applications. Assumptions are made during the PRA development as a way to address a particular modeling uncertainty because there is not a single definitive approach. Plant-specific assumptions made for each of the BY/BW internal events PRA technical elements are noted in the individual notebooks. The internal events PRA model uncertainties evaluation is documented in reference 8, and considers the modeling uncertainties for the base PRA by identifying assumptions, determining if those assumptions are related to a source of modeling uncertainty and characterizing that uncertainty, as necessary. The Electric Power Research Institute (EPRI) compiled a listing of generic sources of modeling uncertainty to be considered for each PRA technical element [Ref 17], and the evaluation performed for BY/BW [Ref 8] considered each of the generic sources of modeling uncertainty as well as the plant-specific sources.

Completeness uncertainty addresses scope and level of detail. Uncertainties associated with scope and level of detail are documented in the PRA but are only considered for their impact on a specific application [Ref 8]. No specific issues of PRA completeness have been identified relative to this application, based on the results of the internal events PRA (including internal flood) and fire PRA peer reviews. Since this one-time TS Condition 3.8.1.A CT extension relies on the PRA model in a similar manner to provide risk-informed basis for extension of a Tech Spec CT, it is judged to have no specific issues related to PRA completeness.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
LOOP Initiating Event Frequency: The initiating event analysis develops frequencies for LOOP and DLOOP events based on the data in NUREG/CR-6890 [Ref 19] (updated through 2013). LOOP types include plant-centered, switchyard-centered, grid-related, and severe weather events, and all are partitioned into LOOP and DLOOP events. The NUREG provides plant-specific values applicable to both sites using data through 2013.	The overall approach for the LOOP frequency and fail to recover probabilities utilized is consistent with industry practice. With the Unit 2 buses powered directly from the UAT, a Unit 2 LOOP may not cause a Unit 2 trip, but this potential conservatism is not considered in the calculations. A Unit 2 LOOP is not a significant contributor to the risk results. No impact on Unit 1 LOOP frequency is expected due to the Unit 2 SAT outage. Therefore, this does not represent a key source of uncertainty for the TS Condition 3.8.1.A CT extension calculations.
Failure to recover probabilities for LOOP: The industry wide data in NUREG/CR-6890 [Ref 19] (updated through 2013) is utilized to develop the failure to recover probabilities for the four LOOP categories. The industry wide recovery data is applicable to both sites and is acceptable for the base case analysis.	The overall approach for the LOOP frequency and fail to recover probabilities utilized is consistent with industry practice. The LOOP frequencies utilized in the model are based on NUREG/CR-6890 [Ref 19] as updated with data through 2013. LOOPs are not significant contributors to the risk results. Therefore, this does not represent a key source of uncertainty for the TS Condition 3.8.1.A CT extension calculations.
Grid stability after a reactor trip: The consequential LOOP failure probabilities are based on EPRI and NRC evaluations with different values following a reactor trip or LOCA [Refs 19, 20]. The use of generic data for consequential LOOP events is assumed to be applicable for both sites. The consequential LOOP events are assumed to be dual-unit and are distributed among grid-related, plant-centered, or switchyard-centered based on data from Reference 19.	The consequential LOOP probabilities utilized provide a reasonably realistic modeling. A Unit 2 trip in this configuration would essentially cause a LOOP-like event, so consequential LOOPs are not contributors. As such, this does not represent a significant source of model uncertainty in this application. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Offsite power restoration: Restoration is possible as the switchyard has its own 125V DC distribution system to provide breaker and transformer control power. When offsite power is available at the switchyard, then power is available to charge the batteries needed for breaker control to align power to the site. The specific failure modes of the offsite restoration are implicitly included via the use of the generic LOOP recovery probabilities.	The LOOP recovery probabilities are realistic with slight conservative bias on the recovery times. LOOPs are not significant contributors to the risk results. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Support System Initiating Events (SSIEs): Support System Initiating Event fault trees are developed for loss of Component Cooling Water (CC), loss of Service Water (SX), and loss of Non-Essential Service Water (WS). The loss of support system success criteria are developed consistent with the post-trip configuration requirements (e.g. 1 of 2 SX pumps) and mission time requirements (i.e. 24 hour Mean Time to Repair (MTTR) assumed consistent with the 24 hour mitigation mission time).	Realistic with slight conservative bias because MTTR is typically less than 24 hours. This does not represent a significant source of model uncertainty in this application. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Support System Initiating Events (SSIEs): Increasing use of plant-specific models for support system initiators (e.g. loss of SX, CC, or Instrument Air (IA), and loss of AC or DC buses) have led to inconsistencies in approaches across the industry. The common cause failure (CCF) for the fail-to-run terms is based on annualized mission times using generic alpha factors, but with plant-specific information for the independent failure rate. The use of the generic alpha factors based on industry wide experience is applicable for the site.	Slight conservative bias treatment since alpha factors are known to be high when utilized in an annualized fashion and compared to plant-specific experience. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Support System Initiating Events (SSIEs): Modeling of recovery to prevent support system initiating events is limited to procedurally-directed alignments of standby equipment given failure of running equipment, if such alignments can be accomplished prior to loss of the support system. No additional credit for recovery beyond system failure is modeled.	Slight conservative treatment since credit for recovery beyond system failure could reduce the baseline CDF and LERF risk metrics. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
LOCA initiating event frequencies: The Large and Medium LOCA initiating event frequencies are based on failure probabilities from NUREG/CR-1829 [Ref 21] (interpolated for plant-specific LOCA definitions). Small Non-Isolable LOCA initiating event frequencies are based on failure probabilities in NUREG/CR-6928 [Ref 22], and includes both the pipe break frequency and spontaneous reactor coolant pump seal rupture. Small Isolable LOCA initiating event frequencies due to stuck-open PORVs are calculated directly using NRC data.	The LOCA frequency values represent realistic treatment based on accepted industry data sources. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Operation of equipment after battery depletion: No credit is taken for continued operation of any systems without DC power that normally require DC power for operation. This includes steam generator (SG) level control.	No credit for equipment operation after battery depletion may represent a slight conservative bias. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
RCP seal LOCA treatment: The assumed timing and magnitude of RCP seal LOCAs given a loss of seal injection and thermal barrier cooling can have a substantial influence on the risk profile. The WOG 2000 consensus model [Ref 23] has been implemented, along with the model for the Westinghouse Generation III Shutdown Seals [Ref 24].	The operator action timing assumptions are based on the WOG 2000 consensus model and Shutdown Seal model. Limitations and conditions from the NRC SER related to the Westinghouse Generation III Shutdown Seal model are accommodated. Specifically, for item 2 in the NRC SER, where the identified conditions might occur, the current PRA model of record accounts for it by treating such a condition as a failure of the shutdown seals. For item 4, the additional failure contribution of the SDS Bypass failure mode has been added to a working model that supports a sensitivity calculation. For item 5, plant-specific human error probabilities for both of those requirements exist in the current model of record. No additional exceptions to the limits or conditions exist that may impact applications. A working model sensitivity calculation that includes item 4 and F&O resolutions shows a less than 2% difference in the internal events delta-CDF for Unit 2. Therefore, this does not represent a key source of uncertainty for this application.
Battery life calculations: Design basis calculations indicate that ~8 hours of battery life is available depending on scenario specifics. Credit for 8 hours is utilized in the model for most scenarios without chargers available. Because the SBO coping time is set at 4 hours, 4 hours is used in LOOP power-recovery calculations.	The modeling is realistic given the relatively long battery life without recharge. This may be slightly conservative for SBO scenarios and does not represent a key source of model uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Number of PORVs required for bleed and feed: Plant-specific success criteria calculations have been performed using MAAP to determine the number of PORVs required to open (and timing of opening) for successful bleed and feed cooling. This has been done as a function of the ECCS pumps available. Results show that a single PORV opening represents bleed and feed success for the condition where a charging pump is running. Success is also credited where two PORVs and a single safety injection pump is running. The appropriate success criteria (i.e., 2 PORVs open or 1 PORV opens) are applied depending on the available ECCS pumps for the scenario being modeled.	The modeling is realistic and does not represent a key source of model uncertainty in the TS Condition 3.8.1.A CT extension application.
Impact of failure of pressure relief: For general transients with reactor trip, the PORVs provide pressure relief if needed, and the likelihood of a safety relief valve challenge is sufficiently small that explicit modeling is not required. For general transients (non-ATWS), it is commonly assumed (and evident in success criteria calculations) that opening of any 1 of the 2 PORVs and 3 SRVs is sufficient to preserve RPV integrity below ASME Service Level C.	The approach taken is consistent with that used in other PWR PRAs. The potential impact on CDF due to not explicitly modeling the possibility of overpressure for non-ATWS events is not significant. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Impact of failure of pressure relief: For ATWS scenarios, the number of PORVs and/or SRVs is a function of core reactivity, available AFW capacity, and other parameters as specified in the WOG ATWS model [Ref 25]. Per the WOG model, there may be brief periods of time in which all available pressure relief is not adequate to maintain RCS pressure below the ASME Service Level C pressure. Failure to maintain RCS pressure below the ASME Service Level C pressure is modeled (non-mechanistically) in the PRA as leading to vessel failure and core damage.	Slight conservative bias treatment in assumption that overpressure failure in ATWS cases goes directly to core damage, since RCS vessel failures in most locations would not result in LOCAs in excess of ECCS capability. However, the modeling is in accordance with an industry recognized model and thus does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Operability of equipment in beyond design basis environments: Generally, credit for operation of systems beyond their design-basis environment is not taken. However, each DG requires ventilation to operate successfully. This dependency is modeled to include suction and exhaust dampers (including CCF terms as applicable) and supply fan fail-to-start and fail-to-run terms. Exhaust fans are not modeled in the PRA since their only design-basis function is to prevent the buildup of fumes. Station procedures provide guidance for the emergency restoration of the DG ventilation and for the use of portable ventilation to maintain DG temperatures acceptable, but this option is not credited in the PRA model.	The PRA modeling is consistent with the design basis of the DG ventilation system, so is considered realistic or slightly conservative. Not modeling the proceduralized restoration of DG ventilation is a potential conservatism. Given that a ventilation dependency is modeled, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Operability of equipment in beyond design basis environments: Generally, credit for operation of systems beyond their design-basis environment is not taken. However, given the typical conservatisms associated with the design-basis battery calculations, and the relatively long battery life, explicit representation of load shedding is not assumed to be required to obtain the 8 hour battery life times for non-SBO scenarios.	Realistic with slight conservative bias on assumed battery life time. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Widespread LOOP effects: Credit for TSC actions is not currently used for cognitive error contributions in HRA due to its significant uncertainty. The TSC is implicitly used for execution recovery for long-term actions, but this is not directly affected by a widespread LOOP. Increased stress due to communication challenges is recognized as a source of model uncertainty and is not explicitly included in the LOOP-related HEP calculations.	Lack of credit for TSC actions is slightly conservative. Lack of explicit consideration of increased stress due to a widespread LOOP could be slightly non-conservative, but its effect is expected to be low based on the low likelihood of the event and the already present stress during a "normal' LOOP event. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Piping failure mode: The Internal flood analysis and initiating event frequencies for spray, flood, and major flood scenarios are developed consistent with the EPRI methodology [Ref 26]. The flooding analysis is integrated into the internal events at power model. The use of generic flood frequencies with plant-specific estimates of pipe lengths is suitable for representation of the flood frequencies at the site.	Considered an industry good practice approach, but is not yet a consensus model approach. This is not a source of significant model uncertainty given that a recognized methodology has been applied using plant-specific piping data. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Piping failure mode: The Internal flood analysis and initiating event frequencies for spray, flood, and major flood scenarios are developed consistent with the EPRI methodology [Ref 26]. The flooding analysis is integrated into the internal events at power model. Spray flood scenarios with less than 100 GPM flow do not totally disable the system they arise from. Major flood sources greater than 100 GPM are assumed to totally disable the system they arise from.	Realistic since such a low flowrate would not affect most systems needed to mitigate an accident. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application Assuming major flood sources greater than 100 gpm totally disable the system they arise from is conservative in that the system may not be totally disabled in all cases. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Core melt arrest in-vessel: In-vessel recovery of the molten core by flooding of the reactor cavity and heat transfer through the vessel is not credited in the Level 2 analysis. Uncertainties due to the ability of the cavity to be flooded to sufficient depth, the effects of lower head insulation and instrument penetrations, and the ability to achieve sufficient heat transfer to prevent vessel failure make in-vessel recovery difficult to justify.	Conservative bias treatment in that in-vessel core melt arrest might be feasible in some scenarios. This does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Thermally induced failure of hot leg/SG tubes: The approach follows "Simplified Level 2 Modeling Guidelines," WCAP-16341-P [Ref 27], which many plants are currently using as a basis for updated Level 2 analyses. This WCAP provides a common, standardized method for PWRs with large dry containments to produce an analysis that generally meets capability category II of the ASME PRA Standard [Ref 28]. The guidance particularly addresses the latest understanding for induced steam generator tube ruptures and other Level 2 issues.	Approach is consistent with recent industry approaches and adequate for determination of LERF. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Vessel failure mode: RPV catastrophic failure leading to early containment failure via missiles is extremely unlikely based on studies documented in NUREG-1524 [Ref 29]. No explicit impact on model, since failure mode is assumed to be a small contributor to the overall likelihood of containment failure.	Approach is appropriate for determination of LERF. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Vessel failure mode: The approach follows "Simplified Level 2 Modeling Guidelines," WCAP-16341-P [Ref 27], which many plants are currently using as a basis for updated Level 2 analyses. This WCAP provides a common, standardized method for PWRs with large dry containments to produce an analysis that generally meets capability category II of the ASME PRA Standard [Ref 28]. The guidance particularly addresses the latest understanding for direct containment heating and other Level 2 issues.	Approach is consistent with general industry approaches and appropriate for determination of LERF. Therefore, this does not represent a key source of uncertainty in this application.
Vessel failure mode: Ex-vessel steam explosions noted as very unlikely based on reference to generic studies. Based on WCAP-16341-P [Ref 27], this is a greater issue for free-standing reactor cavities (as opposed to excavated cavities). Because BBW is an excavated cavity, steam explosions do not pose a failure mechanism for early containment failure.	Approach is appropriate for determination of LERF for Braidwood and Byron. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Ex-vessel cooling of lower head: No credit for ex-vessel cooling.	No credit for ex-vessel cooling of the lower head represents a realistic treatment with a slight conservative bias. Therefore, this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Core debris contact with containment: This is not considered as an early failure mechanism because there is no direct path for core debris to contact the containment shell.	The modeling reflects the plant design. Therefore this does not represent a key source of uncertainty in the TS Condition 3.8.1.A CT extension application.
Containment integrity following vessel rupture event: Vessel rupture sequence is assumed to not result in concurrent containment failure coincident with the vessel rupture.	Vessel rupture frequency is on the order of E-7, i.e., very small, such that potential impact on LERF is also small. Containment integrity following vessel rupture is therefore not identified as a candidate source of model uncertainty.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Condensate Storage Tank Inventory: The inventory in the Condensate Storage Tank (CST) is shown to be sufficient for the full 24 hour mission time modeled in the PRA. The service water (SX) system is the safety related suction source for auxiliary feedwater (AF) pumps. The suction source for AF pumps automatically switches to SX on low CST suction pressure.	The CST is the preferred source of water for AF and is sufficient for the PRA mission time, but service water is the safety related suction source for AF. Therefore, the duration the CST is able provide suction for AF pumps is not a key source of model uncertainty for applications.
Human Error Probabilities (HEPs): Detailed evaluations of HEPs are performed for the risk significant human failure events (HFEs) using industry consensus methods. Mean values are used for the modeled HEPs. Uncertainty associated with the mean values can have an impact on CDF and LERF results.	Sensitivity cases for the base internal events PRA (HEP values of 5th or 95th percentile value HEPs) show that the results are somewhat sensitive to HRA model and parameter values. The BY/BW PRA model is based on industry consensus modeling approaches for its HEP calculations, so this is not considered a significant source of epistemic uncertainty. For the TS Condition 3.8.1.A CT extension application, the evaluation process requires appropriate risk management action (RMA) development, including those related to operator actions in the PRA that are pertinent to the extended CT configuration. Refer to Section 3.2 for additional discussion on RMAs.
Dependent HEP values are developed for significant combinations of HEPs that have been demonstrated to appear together in the same cutsets.	The BY/BW PRA model is based on industry consensus modeling approaches for its dependent HEP identification and calculations, so this is not considered a significant source of epistemic uncertainty. For the One-Time TS LAR process, the evaluation process requires appropriate risk management action (RMA) development, including those related to operator actions in the PRA that are pertinent to the TS CT extension configuration. Refer to Section 3 for additional discussion on RMAs.
Common Cause Failure: Common cause failure values are developed using available industry data.	The BY/BW PRA model is based on industry consensus modeling approaches for its common cause identification and value determination, so this is not considered a significant source of epistemic uncertainty. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.

Table 3.6-1

ASSESSMENT OF INTERNAL EVENTS PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Inter-system LOCA (ISLOCA): The detailed ISLOCA analysis includes the relevant considerations listed in IE-C12 of the ASME/ANS PRA Standard [Ref 28] and accounts for common cause failures and captures likelihood of different piping failure modes.	The values utilized provide a reasonable best-estimate approach, will have only a minor impact on the TS Condition 3.8.1.A CT extension calculations and do not represent a key source of uncertainty.

3.6.2 Assessment of Supplementary FPRA Epistemic Uncertainty Impacts

The purpose of the following discussion is to address the epistemic uncertainty in the BY/BW FPRA. The BY/BW FPRA model includes various sources of uncertainty that exist because there is both inherent randomness in elements that comprise the FPRA and because the state of knowledge in these elements continues to evolve. The development of the BY/BW FPRA was guided by NUREG/CR-6850 [Ref 30], and the BY/BW FPRA model used consensus models described in NUREG/CR-6850. Section 4.7 provides a detailed discussion of the Peer Review F&Os and the resolutions.

BY/BW used guidance provided in NUREG/CR-6850 [Ref 30] and NUREG-1855 [Ref 17] to address uncertainties associated with FPRA for the Condition 3.8.1.A CT extension assessment. As stated in Section 1.5 of NUREG-1855:

> "Although the guidance does not currently address all sources of uncertainty, the guidance provided on the process for their identification and characterization and for how to factor the results into the decision making is generic and is independent of the specific source. Consequently, the process is applicable for other sources such as internal fire, external events, and low power and shutdown."

NUREG-1855 also describes an approach for addressing sources of model uncertainty and related assumptions. It defines:

> "A source of model uncertainty is one that is related to an issue in which no consensus approach or model exists and where the choice of approach or model is known to have an effect on the PRA (e.g., introduction of a new basic

event, changes to basic event probabilities, change in success criterion and introduction of a new initiating event)."

NUREG-1855 defines consensus model as:

"A model that has a publicly available published basis and has been peer reviewed and widely adopted by an appropriate stakeholder group. In addition, widely accepted PRA practices may be regarded as consensus models. Examples of the latter include the use of the constant probability of failure on demand model for standby components and the Poisson model for initiating events. For risk-informed regulatory decisions, the consensus model approach is one that NRC has utilized or accepted for the specific risk-informed application for which it is proposed."

The potential sources of model uncertainty in the BY/BW FPRA model were characterized for the 16 tasks identified by NUREG/CR-6850 Volume 1 Figure 2-1 [Ref 30]. This framework was used to organize the assessment of baseline FPRA epistemic uncertainty and evaluate the impact of this uncertainty on Condition 3.8.1.A CT extension assessment calculations. Table 3.6-2 outlines sources of uncertainties by task and their disposition.

As noted above, the BY/BW FPRA was developed using consensus methods outlined in NUREG/CR-6850 and interpretations of technical approaches as required by NRC. Further, appropriate cable impacts were identified for the systems modeled in the Internal Events PRA and were modeled in the Fire PRA. Fire PRA methods were based on NUREG/CR-6850, other more recent NUREGs (e.g., NUREG-7150 [Ref 32], and published "frequently asked questions" (FAQs) for the FPRA.

In addition to the discussion of sources of model uncertainty in Table 3.6-2, the evaluation of epistemic sources of model uncertainty in the FPRA and associated sensitivity studies identified one modeling uncertainty that may be potentially significant for the applications. This uncertainty is associated with human error probabilities in the FPRA. These are addressed in Table 3.6-3.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
1	Analysis boundary and partitioning	This task poses a limited source of uncertainty beyond the credit taken for boundaries and partitions.	The multi-compartment analysis further reduces this uncertainty by addressing the potential impact of failure of partition elements on quantification. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
2	Component Selection	This task is associated with the development of the linkage between safe shutdown (SSD) analysis component/cable data to fault tree failure modes. Also included in this task is the development and incorporation of multiple spurious operation (MSO) scenarios not addressed in the internal events model fault tree.	The uncertainty associated with this task is mainly related to the identification of all credible MSO scenarios (including fire impact on containment isolation pathways). This source of uncertainty is reduced as a result of multiple overlapping tasks including the MSO expert panel and industry owner's group identification of applicable MSOs. Additional internal reviews of analysis results further reduce the uncertainty associated with this task. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
3	Cable Selection	Treatment of uncertainty is typically not required for this task beyond the understanding of the cable selection approach (i.e., mapping an active basic event to a passive component for which power cables were not selected). Additionally, PRA credited components for which cable routing information was not provided represent a source of uncertainty (conservatism) in that these components are assumed failed unnecessarily.	The limited number of components without available cable routing (most active components credited in the FPRA have their cables routed) as well as the crediting by exclusion of these components (where justified) helps to reduce unnecessary conservatism. A sensitivity analysis for this conservatism is addressed in the FPRA uncertainty analysis. The impact of this uncertainty is limited to those components without cable routing. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
4	Qualitative Screening	Qualitative screening was not performed; however, structures were eliminated from the global analysis boundary and ignition sources deemed to have no impact on the FPRA were excluded from the quantification based on qualitative screening criteria. The only criterion subject to uncertainty is the potential for plant trip.	In the event that a structure which could lead to a plant trip was excluded incorrectly, its contribution to CDF would be small (with a CCDP commensurate with base risk) and would likely be offset by inclusion of the additional ignition sources and the resulting reduction of other scenario frequencies. A similar argument can be made for ignition sources for which scenario development was deemed unnecessary. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
5	Fire-Induced Risk Model	A reactor trip is assumed as the initiating event for all quantification. This is somewhat conservative since not all fires postulated will result in a plant trip.	FPIE and FPRA peer reviews (including the F&O resolution process) and internal assessments are useful in exercising the model and identifying weaknesses with respect to this assumption. Though it is possible that not every scenario will ultimately result in a reactor trip, this is determined to have a minimal impact on the analysis. Typically, these scenarios result in low risk contributors, either due to ignition frequency and/or the resultant CCDP. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
6	Fire Ignition Frequency	Ignition source counting is an area with inherent uncertainty; however, the results are not particularly sensitive to changes in ignition source counts. The primary source of uncertainty for this task is associated with the frequency values from NUREG/CR-6850 [Ref 30] which result in uncertainty due to variability among plants along with some significant conservatism in defining the frequencies, and their associated heat release rates, based on limited fire events and fire test data.	The FPRA utilizes the bin frequencies from NUREG/CR-2169 [Ref 31], which represents the most current approved bin frequencies. As such, some of the inherent conservatism associated with bin frequencies from NUREG/CR-6850 [Ref 30] has been removed. A parametric uncertainty analysis using the Monte Carlo method is provided in section 4.1.1 of the FPRA uncertainty and sensitivity notebook [Ref 16]. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
7	Quantitative Screening	Other than screening out potentially risk significant scenarios (ignition sources), there is no uncertainty from this task on the fire PRA results.	Quantitative screening is limited to refraining from further scenario refinement of those scenarios with a resulting CDF/LERF below the screening threshold. All of the results were retained in the cumulative CDF/LERF, therefore, no uncertainty was introduced as a result of this task. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
8	Scoping Fire Modeling	The approach taken for this task included: 1) the use of NUREG-1805 based fire modeling treatments in lieu of conservative scoping analysis techniques and 2) limited detailed fire modeling was performed to refine the scenarios developed using the NUREG-1805 based fire modeling solutions. The primary conservatism introduced by this task is associated with the heat release rates specified in NUREG/CR 6850 [Ref 30].	The employment of generic fire modeling solutions did not introduce any significant conservatism. Detailed fire modeling was only applied where the reduction in conservatism was likely to have a measurable impact. The NUREG-2178 [Ref 33] heat release rates are used and they constitute the most recent available heat release rate data. Some conservatism in this data is believed to exist. The level of conservatism cannot be quantified at this time. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
9	Detailed Circuit Failure Analysis	Uncertainty considerations for the circuit failure analysis task are addressed via the use of circuit failure mode probability factors in Task 10. No specific uncertainty is associated with the performance of the circuit analysis.	No specific uncertainty is associated with the performance of the circuit analysis. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
10	Circuit Failure Mode Likelihood Analysis	The uncertainty associated with the applied conditional failure probabilities poses competing considerations primarily due to the assumption that all spurious operations occur at the same time. The hot short probability and the hot short duration factors defined in NUREG/CR-7150 [Ref 32] are considered best available data.	Circuit failure mode likelihood analysis was generally limited to those components where spurious operation was expected to be a large contributor to total risk. The assumption that all spurious operations (hot shorts) occur at the same time results in a significant conservatism in the analysis but is not easily assessed with respect to the impact on the overall results. The impact of this conservatism on the FPRA is consistent for all components. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
11	Detailed Fire Modeling	The primary uncertainty in this task is in the area of target failure probabilities. Conservative heat release rates may result in additional target damage. Non-conservative heat release rates would have an opposite effect. Credit for fire brigade response and detection are considered bounding given that the data used for manual non-suppression probability is based on extinguishment of a fire and not control (prevention of further spread) of a fire.	Detailed fire modeling was performed only on those scenarios which otherwise would have been notable risk contributors and only where removal of conservatism in the generic fire modeling solution was likely to provide benefit either via a smaller zone of influence or to allow credit for automatic suppression. Fire modeling was used to evaluate the time to abandonment for control room fire scenarios for a range of fire heat release rates. The analysis methodology conservatism is primarily associated with conservatism in the heat release rates and manual non-suppression probability data specified in NUREG-2178 [Ref 33] and NUREG-2169 [Ref 31]. Uncertainties associated with transient fire scenarios which require co-location of a transient ignition source and transient combustibles also contribute to the uncertainty of this task. This uncertainty will typically result in an overestimation of transient fire scenario risk. See Table 3.6-3 for a further discussion of the impact of uncertainties associated with transient fire scenarios. This conservatism is applicable to all fire scenarios and therefore has limited impact on the TS CT extension calculations.

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
12	Post-Fire Human Reliability Analysis	Human error probabilities represent a potentially large uncertainty for the FPRA given the importance of human actions in the base model. Since many of the HEP values were adjusted for fire, the joint dependency values developed for the FPIE model also represent a potential for introducing a degree of conservatism.	Conservative HEP adjustments were made to the nominal HEP values used in the FPIE model then revisited to address unique fire considerations. A detailed analysis was performed for all fire specific HFEs. A floor value of 1E-06 was applied for all combinations (for all JHEP values less than 1E-05, a justification for the JHEP will be included in the Fire PRA dependency analysis documentation). Uncertainty in HEP values is propagated through the parametric uncertainty analysis. See Table 3.6-3 for additional discussion of the uncertainty associated with operator action impact on the FPRA.
13	Seismic-Fire Interactions Assessment	Since this is a qualitative evaluation, there is no quantitative impact with respect to the uncertainty of this task.	Seismic fire interaction has no impact on fire risk quantification. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
14	Fire Risk Quantification	As the culmination of other tasks, most of the uncertainty associated with quantification has already been addressed. The other source of uncertainty is the selection of the truncation limit.	Convergence sensitivities were performed to demonstrate that the truncation limit used was appropriate. No further sensitivity with respect to truncation is required [Ref 16]. Therefore, this does not represent a key source of uncertainty and will not be an issue for TS Condition 3.8.1.A CT extension calculations.
15	Uncertainty and Sensitivity Analyses	This task does not introduce any new uncertainties but is intended to address how uncertainties may impact the fire risk.	N/A

Table 3.6-2

FIRE PRA SOURCES OF MODEL UNCERTAINTY

Task #	Description	Sources of Uncertainty	Disposition for TS CT Extension Impact
16	FPRA Documentation	This task does not introduce any new uncertainties to the fire risk.	The documentation task compiles the results of the other tasks. See specific technical tasks for a discussion of their associated uncertainty and sensitivity.

Table 3.6-3

TREATMENT OF SPECIFIC FIRE PRA EPISTEMIC UNCERTAINTY IMPACTS

Source of Uncertainty and Assumptions	Model Sensitivity and Disposition
Uncertainties associated with the assumptions and method of calculation of HEPs for the Human Reliability Analysis (HRA) may introduce uncertainty. Detailed evaluations of HEPs are performed for the risk significant human failure events (HFEs) using industry consensus methods. Mean values are used for the modeled HEPs. Uncertainty associated with the mean values can have an impact on CDF and LERF results.	The fire risk importance measures indicate that the results are somewhat sensitive to HRA model and parameter values. The BY/BW FPRA model HRA is based on industry consensus modeling approaches for its HEP calculations, so this is not considered a significant source of epistemic uncertainty. However, the TS LAR procedure will require appropriate risk management action (RMA) focus on human performance for extended CT entry, e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration. Refer to Section 3.3 for additional discussion on RMAs.

3.6.3 Uncertainty Analysis Conclusions

The uncertainty analysis addresses the three generally accepted forms of uncertainty - parameter, model, and completeness uncertainty. The parameter uncertainty assessment indicates that the use of the point estimate results directly for this assessment is acceptable [Ref 8]; there is no major form of completeness uncertainty that impacts the results of this assessment; the model uncertainty assessment uses one sensitivity study to disposition a source of uncertainty related to RCP Shutdown Seal modeling and an open internal events F&O and one sensitivity study Fire model Human Reliability Analysis (HRA).

3.7 RISK SUMMARY

This analysis demonstrates with reasonable assurance that the proposed TS change is within the current risk acceptance in RG 1.177 for one-time changes. As shown in Tables 3.5-1 and 3.5-2, the calculated FPIE,FPRA, and seismic risk metrics justify a TS Condition 3.8.1.A extension time up to the requested amount of time without quantitatively considering compensatory measures. The quantitative results combined with effective compensatory measures to maintain low risk ensure the proposed TS change meets the intent of the ICCDP and ICLERP acceptance guidelines.

4.0 TECHNICAL ADEQUACY OF PRA MODEL

This section provides information on the technical adequacy of the Byron Nuclear Power Plant (BY) Probabilistic Risk Assessment (PRA) internal events model (including internal flooding) and the BY Fire PRA model in support of the license amendment request to extend the Tech Spec Condition 3.8.1.A CT.

The current internal events model (including internal flooding) is a combined PRA model that represents all the units at both Byron and Braidwood (i.e., Byron Unit 1, Byron Unit 2, Braidwood Unit 1, and Braidwood Unit 2). The PRA model is built with a common one-top fault tree, including individual basic events for both Unit 1 and Unit 2 components. The vast majority of the components for Byron and Braidwood are the same, so the vast majority of the fault tree represents both units at both sites. Differences that impact the PRA logic are reflected in the combined PRA fault tree and activated by flags to produce site-specific and unit-specific PRA results.

Separate databases exist for Byron and Braidwood to reflect different operating experience at each site. Separate quantifications are performed for each unit by applying unit-specific flags and the appropriate site-specific database, along with site-specific recovery rules. Site-specific, unit-specific cutset results for each unit are produced (i.e., Byron Unit 1, Byron Unit 2, Braidwood Unit 1, and Braidwood Unit 2).

The internal flooding PRA in integrated into the internal events model, and similarly reflects plant-specific or unit-specific differences through the use of flag events and site-specific databases.

The Fire-PRA is built to integrate with the internal events using this approach. Due to the physical differences at the plants that impact the Fire PRA, separate FRANX files are developed and applied to produce site-specific results.

Exelon employs a multi-faceted approach to establishing and maintaining the technical adequacy and fidelity of PRA models for all operating Exelon nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process and the use of self-assessments and independent Peer Reviews.

All the PRA models described below have been peer reviewed, and the review and closure of all finding-level F&Os from the peer review have been independently evaluated to confirm that the associated model changes did not constitute a model upgrade. This review included F&Os that were associated with "Met" supporting requirements. No focused-scope peer reviews were required or performed as part of the independent F&O closure review. Expectations regarding preparation for the review (NEI 05-04, Section 4.2) and conduct of the self-assessment by the host utility (NEI 05-04, Section 4.3) were addressed prior to conduct of this review. This included documentation by the host utility of resolution of the prior PRA peer review finding-level F&Os and preparation of the information required for this independent assessment. The documented bases for F&O closure provided by the model development team included a written assessment whether the resolution constituted PRA maintenance or PRA upgrade.

The multi-disciplinary team of eight reviewers meet the independence and relevant peer reviewer qualifications requirements in the PRA Standard and related guidance. The 171 F&Os were divided into ten review units, each of which was assigned to at least two of the reviewers. In general, the review units were based on technical elements, but in some cases the technical element was broken up across review units based on the specific content of the F&Os and where they fit best.

Reference 44 provides additional details of the F&O closure review, including the approach taken:

- The process guidance in NEI 05-04, Section 4.6, was applicable to this review.
- The independent technical review team reviewed the documented bases for closure of the finding-level F&Os prepared by the host utility.

- The independent technical review team determined whether the finding-level F&Os in question had been adequately addressed and could be closed out by consensus.

- As part of this process each F&O was reviewed regarding whether the closure response represented PRA maintenance or a PRA upgrade.

- Details of the F&O Closure review assessment are documented in Tables A-1 and A-2 of the Byron and Braidwood F&O Closure Technical Report.

- Appendix C of the Byron and Braidwood F&O Closure Technical Report provides clarification that the completion of the F&O Closure Review resulted in all closed Findings meeting Capability Category II (CC-II) for all the applicable supporting requirements (SRs) of ASME/ANS RA-Sa-2009 as endorsed by RG 1.200 Revision 2.

- Section 2.1.4 of the F&O closure report specifically states that the closure review team concluded that all SRs where the F&Os have been closed are now MET at CC II.

Sections 4.6.2 and 4.7 summarize the peer review and peer review Fact and Observation (F&O) finding closure reviews of the Byron internal events PRA (including internal flooding) and fire PRA models, respectively, and also provides the disposition of all open peer review F&O findings including the disposition of the open findings relative to this application.

Note that, for the internal events PRA (including internal flooding), all F&Os apply to both sites and units. For the Fire PRA, all F&Os were evaluated for their applicability to both sites and units, and their resolution was applied to both sites and units, as applicable.

4.1 PRA QUALITY OVERVIEW

The quality of the Byron and Braidwood FPIE PRA is important in making risk-informed decisions. The importance of the PRA quality derives from NRC Policy Statements as implemented by RGs 1.174 and 1.177, rule-making and oversight processes. These can be briefly summarized as follows using the words of the NRC Policy Statement (1995):

1. *"The use of PRA technology should be increased in all regulatory matters to the extent supported by the state-of-the-art...and supports the NRC's traditional defense-in-depth philosophy."*

2. *"PRA...should be used in regulatory matters...to reduce unnecessary conservatism..."*

3. *"PRA evaluations in support of regulatory decisions should be...realistic...and appropriate supporting data should be publicly available for reviews."*

4. *"The Commission's safety goals...and subsidiary numerical objectives are to be used with appropriate consideration of uncertainties in making regulatory judgments..."*

5. *"Implementation of the [PRA] policy statement will improve the regulatory process in three ways:*

   - *Foremost, through safety decision making enhanced by the use of PRA insights;*

   - *Through more efficient use of agency resources; and*

   - *Through a reduction in unnecessary burdens on licensees."*

PRA quality is an essential aspect of risk-informed regulatory decision making. In this context, PRA quality can be interpreted to have five essential elements:

- Scope (Section 4.2): The scope (i.e., completeness) of the FPIE PRA. The scope is interpreted to address the following aspects:
  - Challenges to plant operation (Initiating Events):
    - ➢ Internal Events (including Internal Floods)
    - ➢ External Hazards
    - ➢ Fires
  - Plant Operational states:
    - ➢ Full Power
    - ➢ Low Power
    - ➢ Shutdown
  - The metrics used in the quantification:
    - ➢ Level 1 PRA – CDF

  - Level 2 PRA – LERF
  - Level 3 PRA – Health Effects

- Fidelity (Section 4.3): The fidelity of the PRA to the as-built, as-operated plant.

- Standards (Section 4.4): ASME/ANS PRA Standard [Ref. 4 and Ref 5] as endorsed by the NRC in Regulatory Guide 1.200 [Ref. 1].

- Peer Review (Section 4.5): An independent PRA peer review provides a method to examine the PRA process by a group of experts. In some cases, a PRA self-assessment using the available PRA Standards endorsed by the NRC can be used to replace or supplement this peer review.

- Appropriate Quality (Section 4.6): The quality of the PRA needs to be commensurate with its application. In other words, the needed quality is defined by the application requirements.

4.2 SCOPE

Both the Byron internal events PRA model and the Byron internal fire PRA model are at-power models (i.e., they directly address plant configurations during plant modes 1 and 2 of reactor operation). The models include both core damage frequency (CDF) and large early release frequency (LERF). Internal flooding is included in both the CDF and LERF internal events PRA models.

4.3 FIDELITY: PRA MAINTENANCE AND UPDATE

The Exelon risk management process for maintaining and updating the PRA ensures that the PRA model remains an accurate reflection of the as-built and as-operated plants. This process is defined in the Exelon Risk Management program, which consists of a governing procedure (ER-AA-600, "Risk Management" [Ref. 34]) and subordinate implementation procedures. Exelon procedure ER-AA-600-1015, "FPIE PRA Model Update" [Ref. 35] delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating Exelon nuclear generation sites. The overall Exelon Risk Management program, including ER-AA-600-1015, defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on CDF is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, Exelon risk management procedures provide the guidance for particular risk management and PRA quality and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for Exelon nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10CFR50.65 (a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on a four year cycle; shorter intervals may be required if plant changes, procedure enhancements, or model changes result in significant risk metric changes.

4.4 STANDARDS

The ASME/ANS PRA Standard provides the basis for assessing the adequacy of the Byron and Braidwood PRA as endorsed by the NRC in RG 1.200, Revision 2. The predecessor to the ASME/ANS PRA Standard was NEI 00-02 which identified the critical internal events PRA elements and their attributes necessary for a quality PRA.

4.5 PEER REVIEW AND PRA SELF-ASSESSMENT

There are three principal ways of incorporating the necessary quality into the PRA in addition to the maintenance and update process. These are the following:

- A thorough and detailed investigation of open issues and the implementation of their resolution in the PRA.
- A PRA Peer Review to allow independent reviewers from outside to examine the model and documentation. The ASME/ANS PRA Standard specifies that a PRA Peer Review be performed on the PRA.
- The use of the ASME/ANS PRA Standard to define the criteria to be used in establishing the quality of individual PRA elements.

There have been several assessments to support a conclusion that the Byron and Braidwood PRA model adequately meets the expectations for PRA scope and technical adequacy as presented in USNRC RG 1.200, Revision 2 [Ref 4].

The Pressurized Water Reactors Owners Group (PWROG) performed a full scope internal events PRA and internal flooding PRA peer review of the BB internal events PRA which examined the BB011b [Ref 9] Model of Record (MOR) and superseded all prior peer reviews and self-assessments. One peer review was performed which addressed the models for both sites, given the use of one model and flags to allow quantification for each site and each unit at each site. The majority of the peer review findings were addressed in the BB016a MOR [Ref 10].

An F&O finding closure review of the peer review findings using the BB016a model and documentation was performed in February of 2017 [Ref 11]. Following that closure review, one finding remains open; the disposition of this finding with respect to this application is provided in Table 4-2. The dispositions of the remaining finding-level F&Os were accepted by the F&O closure review team as PRA maintenance not requiring focused scope review, as documented in Reference 9, section 1.2.

The F&O closure review was performed pursuant to Appendix X to NEI 05-04, 07-12, 12-13 guidance concerning the process for "Close Out of Facts and Observations," which NRC staff accepted in [Ref 50]. Consistent with this process, the Byron and Braidwood F&O Closure Technical Report documents the following [Ref 44]:

- The closure team was provided with a written assessment and justification of whether the resolution of each F&O constituted a PRA upgrade or maintenance update.
- The independence requirement of the reviewers and documentation of the reviewers was met.
- The qualification of the reviewers for the technical elements being associated with the F&Os being reviewed were satisfied in accordance with the ASME/ANS PRA Standard.
- Most of the independent assessment team had conducted other Peer Reviews as well as F&O Closure Review following the Appendix X process.

With the disposition of the single open peer review finding, the BB FPIE PRAs meet the requirements for PRA technical adequacy for these applications.

It should be noted that PRAs can be used in applications despite not meeting all of the Supporting Requirements of the ASME/ANS PRA Standard. This is well recognized by the NRC and is explicitly stated in the ASME/ANS PRA Standard.

4.6 APPROPRIATE PRA QUALITY

The PRA is used within its limitations to augment the deterministic criteria for plant operation. This is confirmed by the PRA Peer Review and the PRA Self-Assessment. As indicated previously, RG 1.200 also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated in to the PRA model, consistency with applicable PRA Standards, relevant peer review findings, and the identification of key assumptions) is discussed below.

4.6.1 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE) is Exelon's PRA model update tracking database. These UREs are created for all issues that are identified with a potential to impact the PRA model. The URE database includes the identification of those plant changes (e.g. SSCs, procedures) that could impact the PRA model. A review of the current open items in the URE database associated with plant changes for Byron is summarized in Table 4-1 along with an assessment of the impact for this application.

The results of the assessment documented in Table 4-1 are that none of the plant changes have any measurable impact on the TS CT extension request.

Table 4-1

IMPACT ON THE BYRON PRA MODEL OF PLANT CHANGES SINCE THE LAST MODEL UPDATE

URE Number	Description	Impact on the Application?	Disposition
BB-1000	Timing for 1CV-ALL operator action	No	Potential model improvement; this action is not important in this application
BB-1035	F&O SY-B12-01 (HVAC dependency modeling)	Yes	Addressed in Working Model Sensitivity calculation
BB-1092	Leakage into Aux Building from Containment	No	Preliminary conclusion of no impact on internal events or internal flooding analysis; kept open to review updated procedures at next periodic update
BB-1094	Multiple EC - MCR Fire Modifications, modifications are being made to respond to the NRC discovery of a circuit design deficiency for PORV response to a design basis MCR fire.	No	No impact to FPIE, FPRA is conservative
BB-1100	Fire mitigating actions to remove PORV control power fuses	No	No impact to FPIE, FPRA is conservative
BB-1101	WS Floods with SX mitigation action	No	Potential model improvement to better represent different recovery action for WS and SX mitigation actions; negligible impact on model expected
BB-1102	Containment isolation action in CDF results	No	To be closed; action no longer shows up in CDF results
BB-1103	Fire - spurious opening of containment vent/purge valves	No	Valves are power-locked out, precluding spurious operation
BB-1105	Mission times on specific XVOC events	No	Negligible impact on base model and no impact on application expected, though the modification is included in the Working Model Sensitivity calculation
BB-1106	Screening HEPs needing improved evaluation	No	Review two screening HEPs that are near the threshold for requiring detailed analysis if they remain there in the next update

Table 4-1

IMPACT ON THE BYRON PRA MODEL OF PLANT CHANGES SINCE THE LAST MODEL UPDATE

URE Number	Description	Impact on the Application?	Disposition
BB-1109	MOVs 1(2)CC9415 circuit breaker position change	No	Planned plant modification to change the normal positions of the circuit breakers for these MOVs from On to Off
BB-1110	Review NO-CUE-RQD events	No	Potential documentation improvement to improve supporting arguments for Fire HRA events that do not require a specific cue modeled
BB-1111	Pressure switch power supplies	No	Potential model improvement identified by Fire PRA to include control power to specific pressure switches, though the similar power to the pumps is already modeled
BB-1112	Evaluate benefit of auto-start for startup feedwater pump	No	Potential plant and model improvement to investigate in the future or if requested
BB-1115	Timing support for 1CC9519----HXVOA	No	Potential model improvement in this one specific HEP which does not show as important for this application
BB-1117	Review of updated procedures	No	Potential model improvement in this one specific HEP which does not show as important for this application To be performed during next periodic update
BB-1119	Update some Internal Flooding HEPs and JHEPs	No	Negligible impact on base model and no impact on application expected, though the modification is included in the Working Model Sensitivity calculation
BB-1121	Add SDS Bypass Failure Mode	Yes	Addressed in Working Model Sensitivity calculation

4.6.2 Consistency with Applicable PRA Standards

The FPIE PRA model of record (MOR) for this evaluation is Revision BB016a as documented in BB-PRA-014, Quantification Notebook, Revision BB016a [Ref 8]. A peer review of this model was performed in July 2013 to assess the technical adequacy of the internal events and internal flooding models. The Peer Review report is documented in LTR-RAM-II-13-067-NP [Ref 9].

LTR-RAM-II-13-067-NP identified six supporting requirements that were evaluated as not being met. In addition there were 10 supporting requirements that were assessed as being at Capability Category I. Many of the Facts and Observations (F&O) from that peer review have been addressed in the current MOR used for this assessment. A PRA Finding Level F&O Technical Review was conducted in February 2017 per guidance in NEI 05-04/07-12/12-06 Appendix X (ADAMS accession number: ML16158A035) [Ref 43], which resulted in the closing of all but one finding. The results of this review are documented in 032299-RPT-05 [Ref 44]. The only remaining finding is shown in Table 4-2 below.

Table 4-2

BYRON / BRAIDWOOD NOT MET AND CAPABILITY CATEGORY I SUPPORTING REQUIREMENTS

Supporting Requirement	Capability Category	Evaluation Impact
SY-B12	Not Met	Updated room cooling calculations and survivable temperature evaluations have been performed and indicate support for the current modeling assumptions for most scenarios for the Engineered Safety Feature (ESF) and Non-ESF Switchgear Rooms. The only identified potential impact on the model is for high energy line break (HELB) scenarios, which are an overall small contributor to the baseline risk results. Working model modifications that insert new HELB-related room cooling requirements shows a small increase in baseline CDF and LERF, but these increases do not trigger consideration of an emergent model update per the Exelon Risk Management procedures. Model changes to incorporate these additional HELB-related room cooling requirements are tracked in the URE (Updating Requirements Evaluation) database and will be incorporated into the internal events and fire PRA models of record in the future according to procedures. This change does not incorporate new methods and is not expected to result in significant changes in the risk results, so is not an Upgrade to the PRA. A working model sensitivity calculation that includes this F&O resolution and other working model changes shows a less than 2% difference in the internal events delta-CDF for Unit 2 for this application. This 2% difference is below the typical resolution of the PRA results, since, for example, the convergence only has to be within 5% of a lower truncation result.

4.6.3 Identification of Key Assumptions

The key assumptions that introduce uncertainties for this application are summarized in Section 3.6. None of the uncertainties are judged to have a significant impact on this application.

4.7 FIRE PRA PEER REVIEW RESULTS AND F&OS

The Braidwood (Units 1 & 2) and Byron (Units 1 & 2) Fire PRA (FPRA) peer reviews were performed October 2015 and June 2015, respectively, using the NEI 07-12 Fire PRA peer review process [Ref 7], the ASME / ANS PRA Standard [Ref 5] and USNRC RG 1.200, Revision 2 [Ref 4]. These peer reviews used the 11b-FL MORs [Refs 12, 13] and superseded all prior peer reviews and self-assessments. The purpose of this review was to establish the technical adequacy of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. These FPRA peer reviews were full-scope reviews against all technical elements in Part 4 of the ASME/ANS PRA Standard [Ref 5], including the Referenced internal events supporting requirements (SRs). The peer review noted a number of facts and observations (F&Os). A review of the closure of the majority of finding-level F&Os was performed in February 2017. The finding F&Os which remain open and their disposition with respect to this application are provided in Table 4-2.

Table 4-3 documents the disposition for each finding-level F&O as a potential Upgrade, as defined in ASME/ANS Standard [Ref 5], including the basis for the determination that the disposition represents PRA maintenance, as opposed to PRA upgrade (in the "Upgrade, Y/N (basis)" Column). The dispositions of the finding-level F&Os were accepted by the F&O closure review team as PRA maintenance not requiring focused scope review, as documented in Reference 11, section 1.2.

With the disposition of the open peer review findings, the Byron and Braidwood FPRAs meet the requirements for PRA technical adequacy for these applications

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
16-4	CS-B1	Cable Selection and Location	**Open**	Based on information provided there is lack of details to meet capability category II/III as the only statement is in Section 3.8 of the 'Braidwood Fire PRA Cable Selection Notebook (BW-PRA-021.03), Rev 0' : "The BW Fire PRA reviewed the electrical coordination calculations for applicability to the Fire PRA. These were reviewed for each of the credited power supplies in the	There is no information on an analysis process or if anything was identified. NUREG/CR 6850 section 3.5.4.1 Step 4.1 -1. It is not the intent of this step to duplicate analyses that have already been completed. Rather, the goal is to confirm that existing analyses and studies satisfy baseline assumptions of the Fire PRA. In most cases, electrical coordination studies will exist as part of the general plant design basis or Appendix R analysis. Thus, this step's evaluation should consist of a summary-level review of the existing	Either provide references to documents that supports the review and/or analysis of coordination or perform such task and identify components, if not identified then clearly state that.	The review of electrical coordination and circuit protection is not complete. A tabulation of power supplies is provided in Appendix C of PRA-021-03. Coordination of each supply is indicated in the table and appropriate calculation references are provided. However, the table is not complete. It does not include all of the power supply components credit in the fire PRA. In addition, several notes	No (clarification of references for documentation of acceptability).	The breaker coordination review for both Byron and Braidwood was performed by reviewing the breaker coordination calculations. Where breaker coordination was confirmed, no model changes are required. The review of breaker coordination calculations resulted in identification of specific breakers and specific buses for which breaker coordination could not be demonstrated. For these buses/breakers the load cables will be modeled as additional cables causing failure of the bus. The review was performed in accordance with the requirements of NUREG/CR-6850. No credit for cable length was required since the more conservative

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				model." This did not provide Analysis or Identified any additional requirements only stated that it was reviewed. (This F&O originated from SR CS-B1)	calculations / analyses to identify any documented cases of no coordination that might impact the Fire PRA. This continues on but the basis of this F&O to either reference what analysis has been done in the past, what was done for the Fire PRA or Perform the proper overcurrent coordination and protection study.		refer to items that have not been fully evaluated. Note that URE-BB-1104, which tracks completion of the evaluation, is referenced in Table C-1.		approach of failing the bus for the uncoordinated load cables was applied. The results of this review will be incorporated into a revised Fire PRA model. Several breakers associated with the 480 V load centers and all breakers on the 120 V AC instrument buses were found to lack adequate coordination. The associated load cables will be included in the model as cables causing failure of the bus. The updated modeling for the uncoordinated breakers consisted of listing the associated load cables against the bus as cables causing failure of the bus. This includes the total length of the load cable so

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
									that any fault anywhere along the length of the cable will result in failure of the associated bus. This change is only model maintenance as it applies methods already implemented in the Fire PRA and evaluated by the peer review.
18-12	UNC-A1	Uncertainty	**Open**	Some anomalies were observed in the database that was used for the uncertainty analysis which was different from that used in the FPRA. (This F&O originated from SR UNC-A1) DELETE LINK TO A2	The equation used for 18.15-0_F001U_IGF is incomplete due to the 80 character limitation of the field in the database. For some Basic Events, there was no Type Code, Equation, or Error Factor, including: 0AP-XTIE-0-HHBOA-F 0CC-RUNOUT-HPMOA-F	Per the F&O 24-14 resolution, "Consider performing a consistent review for the uncertainty analysis."	Related F&O: 24-14 The first three basic event examples provided in the F&O were examined. The distribution field was blank for all three.	See F&O 24-14	A review and update, if needed, of the basic event (BE) probability distributions used in the parametric uncertainty analysis is required. Some potential discrepancies may exist between the database used for the parametric uncertainty, for UNCERT runs, and the probability distributions that should apply to some of the basic events. It is anticipated that this review may identify some changes required

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
					0SX005-----HMVOA-F 0SX007-ES13HMVOA-F 0VA-CHARFANHFNOA-F 0VA-CVDAMP-HDMOA-F 0VA-FANS---HFNOA-F				in the parametric uncertainty analysis but a significant change in the probability distribution of the FPRA total CDF and LERF results is not expected. This issue will be resolved in conjunction with the next FPRA model update. The impact of this issue is limited to the parametric uncertainty analysis. It has no impact on the FPRA results and no impact on this application.
19-8	FQ-E1	Importances	**Partially Resolved**	Document the relative contribution of contributors to LERF. (This F&O originated from SR FQ-F1)	SR LE-G3 was found CAT I for the IE peer review that the PDS relative contribution to LERF is not provided. The relative contribution of contributors to LERF has not been provided for the FPRA based on	Per the F&O 19-16 resolution, "Importances report provide for CDF and LERF quantification."	Section 4.2.1 of the Fire Quantification notebook describes the process for review of importance measures for basic events. The review apparently did not include a	No (clarification).	The documentation and review of results did not include importances by accident progression contributors. Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				REMOVE THIS LINK TO SR FQ-E1	Fire Risk Quantification Notebook BWPRA-021.11 Rev. 0.		review of important measures for components, unless there is a one-to-one relationship between components and basic events.		importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation. The importances by BE, sequence flags and plant damage states will likely be the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.
19-9	FQ-E1	Importances	**Partially Resolved**	HLR-QU-D7 requires review of importance of components and basic events to determine that they make logical sense. (This F&O originated	SR QU-D7 states to review the importance of components and basic events to determine if the make logical sense. Section 4.3 of the Fire Risk Quantification Notebook BW-PRA-021.11 Rev. 0 contains a review	COMPLETE See quantification notebook (PRA-021.11) Section 4.2.1.	Related F&O: 25-9 Basis: Section 4.2.1 of the Fire Quantification notebook describes the process for review of importance measures for	No (documentation only	The documentation and review of results did not include importances by accident progression contributors. Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				from SR FQ-E1)	of the importance measures for top operator actions but does not have a review of importance measures for components and basic events. The tables in Appendix D have the Unit 1 importances but no discussion for the review of components and basic events.		basic events. The review apparently did not include a review of important measures for components, unless there is a one-to-one relationship between components and basic events.		importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation. The importances by BE, sequence flags and plant damage states are the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.
19-11	QU-F2/ FQ-F1	Quantification/ Fire Risk Quantification	**Partially Resolved**	There is no document of the importance measures for Braidwood Unit 2 CDF/LERF from QU-F2 (j). (This F&O originated	SR QU-F2 (j) states to document the importance measure results. Braidwood Unit 2 CDF and LERF importances were not documented in the Fire Risk Quantification Notebook BW-PRA-021.11 Rev. 0. However,	Include the Braidwood Unit 2 CDF and LERF importances in the Fire Risk Quantification Notebook.	The Fire Quantification notebooks include importance measures for basic events and significant human actions. The documentation	No (omitted for one unit but provided for the other).	The documentation and review of results did not include importances by component. Importances by basic event (BE) were provided. This is a documentation issue only since the importance by component can be extracted from the current model but is not

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				from SR FQ-F1)	Braidwood Unit 1 CDF and LERF importances were found in Appendix D of the Fire Risk Quantification Notebook BW-PRA-021.11 Rev. 0.		does not include a presentation of component importance measures.		readily available in the current documentation. The importances by BE are the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.
19-15	LE-G2/ LE-G3/ FQ-F1	Documentation of LERF Analysis / Fire Risk Quantification	**Partially Resolved**	Document the process used to identify plant damage states and accident progression contributors. (This F&O originated from SR FQ-F1)	SR LE-G2 states to document the process used to identify plant damage states and accident progression contributors. This was not provided for the FPRA based on Fire Risk Quantification Notebook BW-PRA-021.11 Rev. 0.	(See F&O 25-22 resolution) Document the process used to identify plant damage states and accident progression contributors for LERF.	Notebook BB-ASM-005 identifies a process and the contributions to LERF by plant damage state (PDS). This analysis was done consistent with the PDS binning in the internal events notebooks. In addition to LERF PDS contributions,	See F&O 25-22	The documentation and review of results did not include importances by accident progression contributors. Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation.

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
							the F&O identifies that the process to identify accident progression contributors for LERF was not provided. The Fire Quantification notebook Section 3.4 refers to the internal events quantification notebook for the process for identification of PDS and accident progression contributors to LERF. The Internal Events QU notebook describes adequately the contributors to PDS, but not		The importances by BE, sequence flags and plant damage states are the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
							for accident sequences. This is related to F&O 25-21		
20-1	IGN-A7	Ignition Frequency	**Partially Resolved with Open Documentation**	During the Peer Review walkdown, three rooms were checked and found to have errors in ignition source counting: 11.4A-1, 11.4A-2, and 11.6-0. (This F&O originated from SR IGN-A7)	During the walkdowns, the following observations were made: 1) In 11.6-0, two transformers were identified. The ISDS Report for the PAU indicates only one transformer. The plant responded that the transformer for this LC was inadvertently not counted. The methodology was to include all XFMRs installed at the plant if they were greater than 45 kVA. Based on this question a review was	Update the ignition source count to correct the discrepancies found and conduct a review to determine if other discrepancies exist.	The ISDS report in the ignition frequency notebook (PRA-021.06) now shows 2 transformers in 11.6-0, in agreement with the findings of the peer review team. The ISDS report for Rooms 11.4A-1 and 11.4A-2, which were mentioned in the F&O, now list equipment (pump, ventilation subsystem, and junction boxes), but it	No (review for completeness of data, no impact on overall technical approach).	Two panels which were missing for the fire scenarios in the Diesel Generator Auxiliary Feedwater Pump (DGAFWP) room were added to that room. Subsequently it was determined that the actual location differed from the change that was incorporated in the current FPRA. Panels 1/2PL85JA and 1/2PL85JB were included in their respective Braidwood Unit 1 DGAFWP room (fire area 11.4-1) but were missing from the Unit 2 DGAFWP room (fire area 11.4-2). These same panels were included in both Byron Unit 1 and Unit 2 DGAFWP rooms (fire areas 11.4-1 and 11.4-

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
					completed and they found that there are 9 LCXFMRs missing from the analysis. 2) In Room 11.4A-2 (or -1), diesel pump, 1 cabinet, and 2 battery chargers were counted. The ISDS Report for the PAU indicates no equipment. The plant responded that these PAUs should contain ignition source counts based on the components located in the PAU. The Unit 1 and 2 Diesel Driven AFW pump rooms did not include the counts of the fixed sources in the room, these will be included in the analysis. The current scenario is a full room burnout		does not list any battery chargers or electrical cabinets that the peer review team observed during their walkdowns. The FPRA team indicated that batteries do not need to be counted, since they are on the pump skid, however, the electrical panel should be counted.		2). It has subsequently been determined that panels 1/2PL85JA are located in fire area 11.4-0 and not in fire area 11.4-1 or 11.4-2. A review of the risk of the quantified scenarios indicates that the impact of the correction in panel locations will result in a net decrease in risk on the order of 1% of the total plant risk. Therefore, the impact of this open item is a small conservatism in the FPRA. This item will be closed in the next revision to the FPRA. Resolution of this issue will have minimal impact on this application given that the impact is a small conservatism in the FPRA.

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
					and will be treated as such. The increase in frequency is not expected to have a significant impact on the analysis as the current CCDP is in the E-04 range.				
20-8	FSS-B2	Fire Scenario Selection and Analysis	**Open**	Currently there is no credit given for operators safely shutting the plant from the remote shutdown panel or from the actions outside the MCR. This results in a CCDP of 1.0 being applied to scenarios that require operator abandonment or where sufficient functionality is	Currently there is no credit given for operators safely shutting the plant from the remote shutdown panel or from the actions outside the MCR. This results in a CCDP of 1.0 being applied to scenarios that require operator abandonment or where sufficient functionality is lost at the Main Control Board (MCB). *this F&O also applies to BW, but was not made during the BW review*	Develop human failure event (HFE) to credit operator actions outside the main control room for the alternate shutdown strategy.	While there is a short paragraph in section 2.2.3 mentioning MCR abandonment, there is no detailed discussion of how MCR abandonment is addressed by the HRA (specific HFEs that are relevant) and how it is included in the Fire PRA model.	No (analysis refinement using methods already in place)	The Main Control Room (MCR) abandonment scenario conditional core damage probability (CCDP) was quantified using a scaling factor applied to the scenario CCDP / CLERP. A scaling factor was applied for each CCDP / CLERP range to reflect the significance of the shift of command and control for the complexity of the shutdown based on the CCDP / CLERP. The un-scaled CCDP / CLERP values for the abandonment scenario used human error

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				lost at the Main Control Board (MCB). *this F&O also applies to BW, but was not made during the BW review* (This F&O originated from SR FSS-B2)					probabilities (HEPs) associated with command and control remaining in the Main Control Room (MCR) as opposed to transfer to the remote shutdown panel. This scaling of MCR abandonment CCDP / CLERP to address the impact of an outside the MCR command and control location has been accepted by the USNRC in Safety Evaluations associated with transition to NFPA 805 at several nuclear plant sites (see the USNRC Safety Evaluations (SEs) for the Turkey Point (ADAMS ML15061A237), St. Lucie (ADAMS ML15344A346) and Farley (ADAMS ML14308A048) NFPA 805 LARs for NRC acceptance of this methodology).

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

<table>
<tr><th>Associated F&Os</th><th>SR</th><th>Topic</th><th>Status</th><th>F&O Description (from Peer Review)</th><th>F&O Basis (from Peer Review)</th><th>Proposed Resolution (from Peer Review)</th><th>Basis for Independent Review Team Disposition (from F&O Closure Review)</th><th>Upgrade, Y/N (basis)</th><th>Impact to PRA Results</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>The following criteria were used for defining the scaling factor to be used for adjusting the CCDP and CLERP values for the control room abandonment scenarios:
<table>
<tr><th>CCDP Range</th><th>Adjusted CCDP</th></tr>
<tr><td>< 0.001</td><td>0.1</td></tr>
<tr><td>≥ 0.001 and < 0.1</td><td>0.2</td></tr>
<tr><td>>0.1</td><td>1.0</td></tr>
</table>
CLERP values are adjusted as follows: CLERP adjusted = CCDP adjusted x (CLERP calculated / CCDP calculated)

The CCDP and CLERP adjustment factors (CCDP adjusted / CCDP calculated and CLERP adjusted / CLERP calculated) are applied to the control room abandonment cutsets as a multiplier to all cutsets for each abandonment scenario.</td></tr>
</table>

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
									The importance of all basic events (BEs) in the cutset file which merges all fire scenario cutsets is increased based on the application of the scaling factor to the control room abandonment cutsets. The use of the adjusted cutset file incorporates the impact of the CCDP and CLERP scaling on the cutsets. Control room abandonment is evaluated for loss of habitability only. Regarding fire-induced loss of control, command and control is expected to remain in the control room and the HEPs for any credited operator actions are adjusted to account for fire. The operator actions credited are fire adjusted HEPs credited

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									for other, non-main control room abandonment scenarios. This includes all operator actions in the model with the exception of actions taken in the control room which are not credited since the control room is abandoned. The application of the CCDP and CLERP adjustments specified above address the impact of the transfer of command and control from the control room to the remote shutdown panel. The HEP time available and the time required for operator action are not altered by control room abandonment. A short delay in initiation of these actions due to control room abandonment is assumed to be accounted for by the

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									CCDP and CLERP adjustment factors.
24-12	HRA-D1	Human Reliability Analysis	**Partially Resolved with Open Documentation**	The JHEPs used to recovery the risk are not supported by the documented dependency analysis. (This F&O originated from SR HRA-D1)	The cutsets include dozens of COMBOs (e.g., COMBO101, COMBO-104, COMBO249, and COMBO322) for which no dependency analysis is documented. The cutsets include dozens of COMBOs (e.g., COMBO143, COMBO150, COMBO158, COMBO190) for which the JHEPs differ by orders of magnitude from those documented in Appendix E.	Consider creating documentation to support the quantified HEPs and JHEPs.	The combinations cited in the original finding for which no dependency analysis is documented no longer reside in the cutsets, so this has been resolved. However, a spot check of combinations reveals continued discrepancies, although very slight, between the value for the combination stated in Appendix E and what is used in the .CUT file. For example,	No (review/update documentation only, no new analysis approach)	This finding remains open as a tracking item to provide a means of confirmation of consistency between the final FPRA human reliability analysis (HRA) report and the recovery file used in the final FPRA quantification model. Several changes made during the final FPRA quantification and the final documentation will reflect these. However, a review of the final data to ensure that no inconsistencies exist is the intent of this open item. This is a documentation issue with no impact on this application.

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							Combination 274 in the Fire HRA Notebook is 8.1E-03, while in the model COMBO274-1 is 8.4E-03. And for Combination 201 it's the difference between 4.1E-03 and 4.2E-03. These are obviously not major impacts on quantification results, but they do concern consistency and traceability between the Fire HRA Notebook and the Fire PRA model.		

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
24-14	UNC-A1	Uncertainty and Sensitivity Analysis	**Open**	A large number of entries in the uncertainty database lack sufficient information for a complete parametric uncertainty analysis. (This F&O originated from SR UNC-A1)	For these Basic Events, there was no Type Code, Equation, or Error Factor, with those showing up in the cutsets including (for example): 0VA-CVDAMP-HDMOA-F, 0CC-RUNOUT-HPMOA-F, 0SX005-----HMVOA-F, 0SX-FAN-TR-HFNRA-F, 0SX-MU-TR--HMVRA-F, 1CV-SUCXFR-HPMOA-F, 1AF01PB-FO-HXVOA-F, 1AF-START--HPMOA-F, and 1RC-PUMPS--HPMOA-F.	Consider performing a consistent review for the uncertainty analysis.	The first three basic event examples provided in the F&O were examined. The distribution field was blank for all three.	No (correction of data).	A review and update, if needed, of the BE probability distributions used in the parametric uncertainty analysis is required. Some potential discrepancies may exist between the database used for the parametric uncertainty, for UNCERT runs, and the probability distributions that should apply to some of the basic events (BEs). It is anticipated that this review may identify some changes required in the parametric uncertainty analysis but a significant change in the probability distribution of the FPRA total CDF and LERF results is not expected. The impact will be limited to the parametric uncertainty analysis and will have no impact on the FPRA

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
									results and no impact on this application.
25-5	FQ-E1	Fire Risk Quantification	**Open**	Some of the top scenarios are found as being not fully developed which may mask the important contributors to fire risk. This SR requires that significant contributors be identified in accordance with HLR-QU-D. HLR-QU-D6 requires that significant contributors be identified and HLR-QU-D7 requires review of important components and basic events to determine that they make	The Byron Fire PRA results are potentially conservative for CDF and LERF. There are several important scenarios that are driving the results that may benefit by reducing the conservatisms. These conservative results may mask other important contributors to the fire risk. Reviewing the Byron Fire PRA Uncertainty and Sensitivity BY-PRA-021.12 Rev. 0 did find a sensitivity on the UNL components which removed all UNL components from every fire	Consider updating the model to remove conservatisms for significant scenarios. The Unit 2 2A diesel generator scenario for CDF and LERF shows to be different in significance as compared to the Unit 1 diesel generator scenarios and the Unit 2 2B diesel generator scenario. This asymmetry should be investigated to determine why this scenario is a top	Finalize the refinement of top scenarios to remove conservatisms and provide a narrative that addresses the various detailed finding in the F&O.	No (refinements performed using the same methods as the original FPRA development)	Refinements were performed to address conservative joint human error probability (JHEP) values and to refine the treatment for the containment isolation valves for the containment mini-purge lines. These changes reduced the overall risk. With these changes completed no specific need for additional refinement is considered to be required. These changes were finalized after the F&O Closure Review and are reflected in the current FPRA results; therefore, they have no impact on this application.

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BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				logical sense. This is not possible with overly conservative scenario models. (This F&O originated from SR FQ-E1)	scenario to see the conservative impact of the unknown location of cable data. This sensitivity provided results with unnecessary conservatisms. This SR requires that significant contributors be identified in accordance with HLR-QU-D. HLR-QU-D6 requires that significant contributors be identified and HLR-QU-D7 requires review of important components and basic events to determine that they make logical sense. This is not possible with overly conservative scenario models. An impact to application	scenario for Unit 2 and to see if these scenarios are modeled correctly. Consider reexamining the influence factors to reduce frequency for base scenarios and possibly other scenarios for both units. Consider reevaluating the significant transient (HGL) scenarios that could be reduced. Additional procedural controls could reduce the HRR and the associated			

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					acceptance limitations from the PRA end state quantification result standpoint is from the acceptance guidelines of RG 1.174 that provides limitations when the total CDF is greater than 1.0E-04 and LERF is greater than 1.0E-05.	HGL contribution. Other considerations may include reviewing the use of the remote shutdown panel to provide consideration to the model that could provide benefit to the control / habitability control room fire scenarios to provide the best estimate of risk. Consider the cross tie of AFW between units as a sensitivity that can be done with and without the RCP seal			

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BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

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						modification. The cross tie capability between units may affect actions, systems, and dependency needed for the accident sequence.			
25-9	FQ-E1	Importances	**Partially Resolved**	HLR-QU-D7 requires review of importance of components and basic events to determine that they make logical sense. The information provided did not meet the intent of providing a review of importance of components and basic events.	SR QU-D7 states to review the importance of components and basic events to determine if they make logical sense. Section 4.3 of the Fire Risk Quantification Notebook BY-PRA-021.11 Rev. 0 contains a review of the importance measures for top operator actions, but this section does not have a review of importance measures for	COMPLETE Importances report provided for CDF and LERF quantification.	Related F&O: 19-9 Section 4.2.1 of the Fire Quantification notebook describes the process for review of importance measures for basic events. The review apparently did not include a review of important measures for components, unless there is	No (clarification).	The documentation and review of results did not include importances by accident progression contributors. Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation. The importances by

Table 4-3
BYRON AND BRAIDWOOD FPRA PEER REVIEW - OPEN FACTS AND OBSERVATIONS - FINDINGS

Associated F&Os	SR	Topic	Status	F&O Description (from Peer Review)	F&O Basis (from Peer Review)	Proposed Resolution (from Peer Review)	Basis for Independent Review Team Disposition (from F&O Closure Review)	Upgrade, Y/N (basis)	Impact to PRA Results
				(This F&O originated from SR FQ-E1)	components and basic events. The tables in Appendix D include the Unit 1 & 2 importances, and there is an example at the beginning of this appendix that includes importance discussion of two components, but there is not any further review of components and basic events to determine that they make logical sense. This information does not meet the intent of providing a review of importance of components and basic events.		a one-to-one relationship between components and basic events.		BE, sequence flags and plant damage states are the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.
25-11	AS-B3/ PRM-B2	Accident Sequence Analysis / Plant Response Model	**Partially Resolved**	Internal events F&O AS-B3-01 does not appear to have been	Reviewing the IE peer review, F&O AS-B3-01 does not appear to have been addressed for	Develop modeling for common cause clogging of	The F&O is partially resolved in internal events model but not	No (review FPIE F&O impact on fire quant and document	This finding is partially resolved in internal events model but not yet resolved in the FPRA model. The

Table 4-3
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				addressed for the Fire PRA analysis. (This F&O originated from SR PRM-B2)	the Fire PRA analysis. AS-B3-01: Potential failure of containment sump suction screens due to debris clogging (a post-accident phenomenological condition) is not represented in the BB fault tree.	containment sump screens due to debris. Include a basis for the quantification. WCAP-16362-NP PRA Modeling Template for Sump Blockage can be used. Alternatively, if the sumps at Byron and Braidwood are "robust" as described in the WCAP, explicit modeling of sump clogging is not necessary and documentation of the issue for the PRA is all that is needed.	yet resolved in fire model. The system notebook describes an acceptable approach for sump clogging based on WCAP-16362-NP. The fault tree modeling is with that approach. This Fire PRA F&O may be closed by 1) resolving the open documentation in the internal events F&O closure review for F&O AS-B3-01 and 2) update the Fire PRM fault tree with the same fault tree modeling as found in the internal events	basis for resolution, no change in analysis approach)	system notebook describes an acceptable approach for sump clogging based on WCAP-16362-NP. The fault tree modeling is consistent with that approach. The new sump clogging value is included in the current (in-process) FPRA model update. Random failure due to containment sump screen clogging will have minimal impact on the FPRA. The logic from the updated FPIE model will be incorporated in the next revision of the FPRA. Resolution of this issue will have minimal impact on this application.

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							model-of-record BB-016-A.		
25-21	FQ-F1	Documentation of LERF Analysis / Fire Risk Quantification	**Partially Resolved**	The documentation for the relative contribution of contributors to LERF was not addressed. (This F&O originated from SR FQ-F1)	SR LE-G3 was found CAT I for the IE peer review that the PDS relative contribution to LERF is not provided. The relative contribution of contributors to LERF has not been provided for the FPRA based on Fire Risk Quantification Notebook BY-PRA-021.11 Rev. 0.	See F&O 25-22 resolution	Notebook BW-ASM-01 identifies a process and the contributions to LERF by plant damage state (PDS). This analysis was done consistent with the PDS binning in the internal events notebooks. In addition to LERF PDS contributions, the F&O identifies that the process to identify accident progression contributors for LERF was not provided.	See F&O 25-22.	Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation. The importances by BE, sequence flags and plant damage states are the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.

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25-22	FQ-F1	Documentation of LERF Analysis / Fire Risk Quantification	**Partially Resolved**	The process used to identify plant damage states and accident progression contributors was not documented. (This F&O originated from SR FQ-F1)	SR LE-G2 states to document the process used to identify plant damage states and accident progression contributors. This was not provided for the FPRA based on Fire Risk Quantification Notebook BYPRA-021.11 Rev. 0.	Document the process used to identify plant damage states and accident progression contributors for LERF.	The Fire Quantification notebook Section 3.4 references to the internal events quantification notebook for the process for identification of PDS and accident progression contributors to LERF. The Internal Events QU notebook describes adequately the contributors to PDS, but not for accident sequences. This is related to F&O 25-21	No (clarification of LERF model applicability to FPRA).	The process used to identify plant damage states and accident progression contributors was not provided in the notebook. Importances by basic event (BE) and sequence flags as well as for LERF plant damage states were provided. This is a documentation issue only since the importance by accident progression contributors can be extracted from the current model but is not readily available in the current documentation. The importances by BE, sequence flags and plant damage states will likely be the more useful input and were provided and reviewed as part of the model development. This is a documentation issue with no impact on this application.

Table 4-3
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26-9	IGN-A7	Ignition Frequency	**Open**	During the Peer Review walkdown, two fairly large electrical wall-mounted cabinets with 14 switches were not counted in 11.4C-0, which is a risk-significant fire zone. (This F&O originated from SR IGN-A7)	The criteria for counting wall-mounted panels is not documented in either the IGN notebook or the walkdown notebook. Size criteria for counting electrical panels is provided in the IGN notebook, however, other criteria consistent with NUREG/CR-6850 should also be considered, such as the number of switches which indicates significant quantities of combustibles, whether the penetrations into the top or sides of the panel are fire sealed, and whether the panel is vented.	Establish and document the criteria for counting wall-mounted cabinets consistent with NRC guidance and evaluate whether the wall-mounted panels in 11.4C-0 should be counted.	The F&O response indicates that Appendix E of the Ignition Frequency notebook gives additional criteria for counting smaller control type cabinets. However, Appendix E does not give criteria for counting wall-mounted cabinets.	No (review of discrepancy for impact on the analysis; no change in technical approach).	Wall mounted panels were screened from the FPRA. Based on further review of the requirements of NUREG/CR-6850 and associated dispositions to NFPA 805 Frequently Asked Questions (FAQs), it has been determined that only those panels with four or fewer switches should have been screened (per NUREG/CR-6850, p. 6-18, discussion of Bin 15 ignition frequency). Identification of all wall mounted panel configurations with four or more switches will be performed and any model changes required to address the results of the walkdowns, which have already been performed, will be incorporated into the current (in-process)

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									Fire PRA update. This change does not incorporate new methods as the approach to modeling panels is the same as in the current model which has been peer reviewed. The resolution of this open item will have a minimal impact on the FPRA results and a minimal impact on this application.

4.8 GENERAL CONCLUSION REGARDING PRA CAPABILITY

The Byron and Braidwood PRA maintenance and update processes and technical capability evaluations provide a robust basis for concluding that the PRA is suitable for use in risk-informed licensing actions, specifically in support of the requested extended CT for TS Condition 3.8.1.A.

5.0 SUMMARY AND CONCLUSIONS

5.1 SCOPE INVESTIGATED

This analysis evaluates the acceptability, from a risk perspective, of a change to the Byron Unit 1 and Unit 2 TS Condition 3.8.1.A for a one-time increase of the CT from 72 hours to 79 days when both Unit 2 SATs are inoperable.

The analysis examines a range of risk contributors as shown in Table 5-1.

Table 5-1

SUMMARY OF RISK INSIGHTS FOR TS CONDITION 3.8.1.A EXTENSION

RISK CONTRIBUTOR	APPROACH	INSIGHTS
Internal Events	Quantify ICCDP & ICLERP for planned configuration • ICCDP < 1E-6 • ICLERP < 1E-7 If exceeded compare to acceptance guidelines with risk management actions implemented to reduce sources of risk • ICCDP < 1E-5 • ICLERP < 1E-6	• Base risk within acceptance guidelines • Compensatory measures further reduce risk
Internal Fire	Qualitatively and quantitatively evaluated: • Identify fire scenarios impacted by configuration • Estimate fire risk impacts due to configuration and quantify ICCDP and ICLERP • Identify compensatory measures	• ICCDP and ICLERP within acceptance guidelines with risk management actions to reduce risk sources. • Internal events compensatory measures apply to fire scenarios • Additional Fire-related compensatory measures identified
Seismic	Estimate incremental seismic risk due to planned configuration	• Seismic risk impacts do not significantly affect CT

Table 5-1

SUMMARY OF RISK INSIGHTS FOR TS CONDITION 3.8.1.A EXTENSION

RISK CONTRIBUTOR	APPROACH	INSIGHTS
High Winds	Qualitatively evaluated.	• High winds risk impacts negligible • High winds risk reduced with compensatory measures for internal events and fire
Other External Hazards	Qualitatively evaluate each hazard based on the BY IPEEE and a re-examination for the specific configuration with both Unit 2 SATs inoperable.	• Other External Event risks were found to be negligible contributors
Overall At-Power Risks	Quantify ICCDP & ICLERP for planned configuration with normal work controls • ICCDP < 1E-6 • ICLERP < 1E-7 If exceeded compare to acceptance guidelines with risk management actions implemented to reduce sources of risk • ICCDP < 1E-5 • ICLERP < 1E-6	• Quantitative guidelines for normal work controls challenged, but acceptable with risk management actions implemented.

5.2 PRA QUALITY

The PRA quality for FPIE and Fire has been assessed and determined to be adequate for this risk application, as follows:

- Scope – Byron PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA has the necessary scope to appropriately assess the pertinent risk contributors.

- Fidelity – The Byron PRA modelsare the most recent evaluation of the risk profile at BY. The PRA reflects the as-built, as-operated plant.

- Standards – The PRA has been reviewed against the ASME/ANS PRA Standard and the PRA elements are shown to have the necessary attributes to assess risk for this application.

- Peer Review - The PRA has received a peer review. Based on addressing the peer review results and subsequent gap analyses to the current standards, the PRA is found to have the necessary attributes to assess risk for this application.
- Appropriate Quality – The PRA quality is found to be appropriate to assess risk for this application.

5.3 QUANTITATIVE RESULTS VS. ACCEPTANCE GUIDELINES

As shown in Table 3.5-1 this analysis demonstrates with reasonable assurance that the proposed TS change is within the current risk acceptance guidelines in RG 1.177 for one-time changes. This combined with effective compensatory measures to maintain lower risk ensures that the TS change meets the intent of the ICCDP and ICLERP acceptance guidelines.

5.4 CONCLUSIONS

This analysis demonstrates the acceptability, from a risk perspective, of a change to the BY TS Condition 3.8.1.A to increase the CT from 72 hours to 79 days when both Unit 2 SATs are unavailable.

A PRA technical adequacy evaluation was also performed consistent with the requirements of ASME/ANS PRA Standard and RG 1.200, Revision 2. Additionally, a review of model uncertainty was performed with this application. None of these identified sources of uncertainty were significant enough to change the conclusions from the risk assessment results presented here.

The assessment of risk from internal events and internal fires did help to identify the following actions as important compensatory measures that will help to reduce the overall risk during the performance of the extended CT:

5.4.1 Compensatory Measures

The following compensatory actions have been identified through review of the FPIE PRA results and are summarized below:

- Each shift, operators should brief on the following actions:
    - Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
    - Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
    - Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate SX cooling
    - Aligning fire protection cooling to centrifugal charging pumps, 2CV01PA and 2CV01PB, upon loss of SX
    - Locally failing air to the Unit 2 AF005 valves on loss of main feedwater
    - BOP DG-22, Diesel Generator Operation after Auto Start
    - 2BOA ELEC-4, Loss of Offsite Power Unit 2
    - 2BEP ES-0.1, Reactor Trip Response Unit 2 actions concerning natural circulation cooldown
    - BOP DO-16, Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank, (U2)
    - BOP CC-10, Alignment of the U-0 CC Pump and U-0 CC HX to a Unit
- Protect the following components
    - 2AF01PB
    - All four diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB
- Limit maintenance unavailability on the following components
    - 2AF01PB, Unit 2 diesel driven AF pump
    - 2AF01PA, Unit 2 motor driven AF pump

- 2DG01KA, Unit 2 Diesel Generator A
- 2DG01KB, Unit 2 Diesel Generator B
- 2AP231X2, MCC 231X2
- 2AP232X1, MCC 232X1
- 1AP132X1, MCC132X1

Based on a review of results from the fire PRA contributors, the following compensatory actions are highlighted as important to reduce the risk from fire events during the performance of the extended TS Condition 3.8.1.A CT:

- Aside from the period of aligning UAT-to-ESF bus supply, maintain SAT supply feed breakers to ESF buses, 2412 and 2422, racked out

- Aside from the period of aligning UAT-to-ESF bus supply, open test switches for breakers 2412/2422 to prevent lockout relays from impacting breakers 2413 and 2414/2423 and 2424 operation

- Each shift, operators should brief on the following actions:
  - Filling the Unit 2 Diesel AF Pump Day Tank from the 125,000 or 50,000 gallon fuel oil storage tanks per 2BOP DO-13
  - Providing makeup capability to the SX Cooling Tower Basin before inventory is low per BAR 0-37-A8 and BOP SX-12

- Risk Management Actions (RMAs) applicable for this extended CT window will be completed per OP-AA-201-012-1001 "OPERATIONS ON-LINE FIRE RISK MANAGEMENT" (these actions protect against fire impacting key redundant equipment).

- Prior to entering the TS 3.8.1.A Action Statement for repair of Unit 2 SATs, an operating crew shift briefing and pre-job walkdowns are suggested to be conducted to reduce and manage transient combustibles and to alert the staff about the increased sensitivity to fires in the fire zones specified in Table 3.3-5. Operating crew shift briefings will continue to be conducted every shift throughout the duration of the CT period. Additionally, planned hot work activities in these fire zones should be minimized during the time within the extended TS Condition 3.8.1.A CT. In the event of an emergent issue requiring hot work in one of the listed zones, additional compensatory actions will be developed to minimize the risk of fire. The fire zones listed in Table 3.3-5 were identified based on risk significance in the FPRA results. Walkdowns are intended to reduce the likelihood of fires in certain zones by limiting transient combustibles, ensuring transients, if required to be present, be located away from fixed ignition sources, and eliminating or isolating potential transient ignition sources, e.g., energized temporary equipment and associated cables.

Table 3.3-5
RISK-SIGNIFICANT FIRE ZONES TO WHICH COMPENSATORY ACTIONS APPLY

Fire Zone	Fire Zone Description
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room
5.2-1	Division 11 ESF Switchgear Room
5.2-2	Division 21 ESF Switchgear Room
2.1-0	Control Room
11.4C-0	Radwaste/Remote Shutdown Control Room
11.7-0	Auxiliary Building HVAC Exhaust Complex
11.6-0	Auxiliary Building General Area, 426' El.

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ATTACHMENT 1: BYRON EXTERNAL HAZARDS SCREENING

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Aircraft Impact	Y	PS2 PS4	From Byron UFSAR Section 3.5.1.6, Aircraft Hazards, the airports and airways in the vicinity of the site are described in Byron UFSAR Subsection 2.2.2.5 (Reference 16). There are no airports with projected operations greater than 500 d^2 movements per year within 10 miles of the site and greater than 1000 d^2 movements per year outside 10 miles, where d is the distance in miles from the site. There are no low altitude federal airways within 2 miles of the site. For the airports and seaplane base within 10 miles of the site (shown in Byron UFSAR Figure 2.2- 3), an analysis has been performed which shows that the probability of an aircraft crashing into the safety-related plant structures is 3.7E-08 per year. Based on this review, the aircraft impact hazard can be considered to be negligible.
Avalanche	Y	C3	The mid-western location of Byron station precludes the possibility of a snow avalanche.
Biological Event	Y	C3 C5	Actions committed to and completed by Byron station in response to Generic Letter 89-13 provide on-going control of biological hazards. These controls are described in Exelon procedure ER-AA- 340, "GL 89-13 Program Implementing Procedure". In addition, station actions taken in response to INPO SOER 07-2 provide an additional layer of biological hazard management. Based on these actions, the potential impact of biological hazard events Is considered negligible and is screened from further consideration.
Coastal Erosion	Y	C3	The mid-western location of Byron station precludes the possibility of coastal erosion.

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Drought	Y	C5	These effects would take place slowly allowing time for orderly plant reductions, including shutdowns.
External Flooding	Y	C1 PS2	The external flooding hazard at the site was recently updated and the flood hazard reevaluation report (FHRR) was submitted to NRC for review on March 12, 2014 (Reference 19). By letter dated September 3, 2015 (Reference 20), the NRC staff concluded that the reevaluated flood hazard mechanisms for Byron are bounded by the current design basis. Subsequently, Byron revised the model used to develop the local intense precipitation (LIP) flood hazard parameters. The revision resulted in minor differences between the LIP parameters described in the external flooding mitigating strategies assessment (MSA) submitted to NRC on September 30, 2016 (Reference 21) and the reevaluated LIP parameters described in the September 3, 2015 letter. Specifically, the revised model resulted in an increase in the maximum flood elevation due to LIP from 870.9 feet to 870.94 feet, which exceeds the plant floor elevation at the east and southwest sides of the turbine building. The NRC staff assessment letter of the Byron MSA dated October 21, 2016 (Reference 22) concluded that this minor increase in maximum LIP elevation is: 1) bounded by an internal flood; and 2) does not adversely impact mitigating strategies equipment. Since this difference is minor and has no impact on implementation of the Byron station mitigating strategy, the NRC concluded that the flood hazards used in the MSA are equivalent to the design-basis of the facility and suitable for use in the MSA. In addition, Byron Station completed an evaluation which concluded that ingress from the revised LIP flood, with higher flood levels and period of inundation, is bounded by an internal flood and that the plant would be able to shutdown safely.

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Extreme Wind or Tornado	Y	C1 PS4	Wind damage is bounded by tornadoes, and the tornado wind speed corresponding to the 1E- 6/yr exceedance frequency is much less than the Byron design value; therefore, damage due to the forces associated with extreme winds or tornados can be screened. For tornado missiles, a plant-specific TORMIS analysis was performed in accordance with the guidance described in the 1983 NRC TORMIS Safety Evaluation Report (Reference 23), as clarified by Regulatory Issue Summary (RIS) 2008-14, "Use of TORMIS Computer Code for Assessment of Tornado Missile Protection." (Reference 24). The CDF associated with tornado missiles is less than 1E-6/yr.
Fog	Y	C1	The principal effects of such events (such as freezing fog) would be to cause a loss of off-site power and are addressed in the weather-related Loss of Offsite Power initiating event in the internal events PRA model for Byron.
Forest or Range Fire	Y	C3	The site landscaping and lack of forestation prevent such fires from posing a threat to Byron station.
Frost	Y	C1	The principal effects of such events would be to cause a loss of off-site power and are addressed in the weather-related Loss of Offsite Power initiating event in the internal events PRA model for Byron.
Hail	Y	C1 C4	The principal effects of such events would be to cause a loss of off-site power and are addressed in the weather-related Loss of Offsite Power initiating event in the internal events PRA model for Byron.

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
High Summer Temperature	Y	C1	The principal effects of such events would result in elevated river and SX Cooling Tower basin temperatures which are monitored by station personnel. Should the temperature exceed the Technical Specification limit, an orderly shutdown would be initiated. Another potential initiating consequence would be to cause a loss of off-site power. These effects would take place slowly allowing time for orderly plant reductions, including shutdowns. At worst, the loss of off-site power events would be subsumed into the base PRA model results.
High Tide, Lake Level, or River Stage	Y	C3	The mid-western location of Byron station precludes the possibility of a high tide condition. High river effects would have negligible impact to the plant due to the installation of cooling towers being the ultimate heat sink.
Hurricane	Y	C4	The mid-western location of Byron station precludes the possibility of a hurricane. In addition, hurricanes would be covered under Extreme Wind or Tornado and Intense Precipitation.
Ice Cover	Y	C1 C3	The principal effects of such events would be to cause a loss of off-site power and are addressed in the weather-related Loss of Offsite Power initiating event in the internal events PRA model for Byron.
Industrial or Military Facility Accident	Y	C1 C3	There are no military facilities within 10 miles of the site. Industrial manufacturing facilities have also been evaluated and determined to not have an impact to the Byron site as discussed in the Byron UFSAR, section 2.2.3 (Reference 16). The evaluation of chemical hazards from military or industrial facilities is performed in accordance with Technical Specification 5.5.18 (Reference 26).

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Internal Flooding	N	None	The Byron Internal Events PRA includes evaluation of risk from internal flooding events.
Internal Fire	N	None	The Byron internal Fire PRA addresses risk from internal fire events.
Landslide	Y	C3	The mid-western location of Byron station precludes the possibility of a landslide. Not applicable to the site because of topography.
Lightning	Y	C1	Lightning strikes are not uncommon in nuclear plant experience. They can result in losses of off-site power or surges in instrumentation output if grounding is not fully effective. The latter events often lead to reactor trips. Both results are incorporated into the Byron internal events model through the incorporation of generic and plant specific data.
Low Lake Level or River Stage	Y	C5	These effects would take place slowly allowing time for orderly plant reductions, including shutdowns.
Low Winter Temperature	Y	C1 C5	The principal effects of such events would be to cause a loss of off-site power. These effects would take place slowly allowing time for orderly plant reductions, including shutdowns. At worst, the loss of off-site power events would be subsumed into the base PRA model results.
Meteorite or Satellite Impact	Y	PS4	The frequency of a meteorite or satellite strike is judged to be very low such that the risk impact from such events insignificant.

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Pipeline Accident	Y	C1	The nearest pipeline to the site is 2.5 miles away and is only a 3-inch diameter pipe. There is no significant hazard to the site from these events. Chemical Hazards transported using pipelines that are located in the vicinity of the plant are analyzed in accordance with Technical Specification 5.5.18 (Reference 26).
Release of Chemicals in Onsite Storage	Y	PS2	Chlorination of water systems is performed using a hypochlorite system. No chlorine gas is stored on-site. Various acids and caustics are stored on-site but pose no hazard to the plant. Chemical Hazards stored and transported in the vicinity of the plant are analyzed in accordance with Technical Specification 5.5.18 (Reference 26).
River Diversion	Y	C3	Due to the great width of the Rock River and the relatively flat surrounding terrain, there is little possibility that rock falls, ice jams or subsidence could completely divert the flow away from the makeup water intake Refer to Byron UFSAR Section 2.4.9(Reference 16).
Sand or Dust Storm	Y	C1 C5	The mid-western location of Byron station prevents sandstorms. More common wind-borne dirt can occur but poses no significant risk to Byron station given the robust structures and protective features of the plant.
Seiche	Y	C1 C3	Seiche was found to not be an applicable external flooding mechanism in Reference 19.
Seismic Activity	N	None	See information in Section 3.2.3 of this application.
Snow	Y	C1 C4	Snow cover is included as an input to the probable maximum flood (PMF) WSE calculations (Reference 19).
Soil Shrink-Swell Consolidation	Y	C1 C5	Based on the discussions and conclusions reached in the Byron UFSAR section 2.5, "Geology, Seismology, And Geotechnical Engineering" (Reference 27, the impact from soil shrink or swell (subsidence or uplift) is expected to be negligible and can be screened from further evaluation.

External Hazard	Screening Result		
	Screened? (Y/N)	**Screening Criterion (Note a)**	**Comment**
Storm Surge	Y	C3	The mid-western location of Byron station precludes the possibility of a sea level driven storm surge.
Toxic Gas	Y	C4	Toxic gas covered under release of chemicals in onsite storage, industrial or military facility accident, and transportation accident.
Transportation Accident	Y	C3 C4 PS2 PS4	Railroad track approaches no closer than four miles to the plant site. There is no heavy traffic in bulk hazardous materials capable of impacting the site. The Rock River is not navigable to barge traffic in the area of the plant site. Chemical Hazards that may result from being transported on local roads that are located in the vicinity of the plant are analyzed in accordance with Byron Technical Specification 5.5.18 (Reference 26).
Tsunami	Y	C3	The mid-western location of Byron station precludes the possibility of a tsunami.
Turbine-Generated Missiles	Y	PS2 PS4	As noted in section 10.2.3 of the Byron UFSAR (Reference 16), the potential for turbine generated missiles is managed through an ongoing station program to monitor turbine performance and integrity. At each refueling outage, a calculation for total unit missile generation probability is made. To make this calculation the operational hours on each of the low pressure turbines is gathered. The missile generation probability for each of the LP turbine rotors is taken from the individual rotor's graph based on the operational time on the rotor. The values for the three rotors are then added together to determine the current missile generation probability for the unit. This value must be below 1.0E- 05 to allow loading the turbine and bringing the unit on line. Based on this ongoing management of the potential for turbine- generated missiles, including a performance related threshold for operation of the turbine, this hazard can be considered negligible and screened from further evaluation.
Volcanic Activity	Y	C3	Not applicable to Byron Station

External Hazard	Screening Result		
	Screened? (Y/N)	Screening Criterion (Note a)	Comment
Waves	Y	C3 C4	Waves are addressed as part of the combined- effects flooding in Reference 19, Flood Hazard Reevaluation Report (FHRR). It is shown that waves will not challenge plant grade of the finished floor elevation of the power block.
Note a – See Attachment 5 for descriptions of the screening criteria.			

ATTACHMENT 2 PROGRESSIVE SCREENING APPROACH FOR ADDRESSING EXTERNAL HAZARDS

Event Analysis	Criterion	Source	Comments
Initial Preliminary Screening	C1. Event damage potential is < events for which plant is designed.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C2. Event has lower mean frequency and no worse consequences than other events analyzed.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C3. Event cannot occur close enough to the plant to affect it.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C4. Event is included in the definition of another event.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	Not used to screen. Used only to include within another event.
	C5. Event develops slowly, allowing adequate time to eliminate or mitigate the threat.	ASME/ANS Standard RA-Sa-2009	
Progressive Screening	PS1. Design basis hazard cannot cause a core damage accident.	ASME/ANS Standard RA-Sa-2009	
	PS2. Design basis for the event meets the criteria in the NRC 1975 Standard Review Plan (SRP).	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	

	PS3. Design basis event mean frequency is < 1E-5/y and the mean conditional core damage probability is < 0.1.	NUREG-1407 as modified in ASME/ANS Standard RA-Sa-2009	
	PS4. Bounding mean CDF is < 1E-6/y.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	
Detailed PRA	Screening not successful. PRA needs to meet requirements in the ASME/ANS PRA Standard.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 8

UNIT 2 SYSTEM AUXILIARY TRANSFORMER 242-2 REPAIR AND TESTING SCHEDULE

ATTACHMENT 8

UNIT 2 SYSTEM AUXILIARY TRANSFORMER 242-2 REPAIR AND TESTING SCHEDULE

Anticipated Schedule for the Replacement and Testing of Byron Station, Unit 2 System Auxiliary Transformer (SAT) 242-2 (For Information Only)

ABB Begins construction by: 7/26/2018
Transformer Design Specifications complete by: 8/3/2018
Construction for installation begins: 11/15/2018
Factory Acceptance Testing completed by: 11/17/2018
Transformer Manufacture complete: ~11/18/2018
Shipping of Transformer to Byron Station: 11/18/2018 – 12/18/2018
Engineering: 8/1/2018 - 12/3/2018
Transportation to site complete by: 12/18/2018
Transformer assembly: 12/19/2018 - 1/18/2019
Installation work window scheduled for: 1/22/2019 – 2/5/2019
Complete – SAT 242-2 Declared Operable: 2/5/2019

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 9

BYRON STATION NUCLEAR PLANT INTERFACE REQUIREMENTS, REVISION 5

BYRON STATION UNITS 1 AND 2
NUCLEAR PLANT INTERFACE REQUIREMENTS (NPIRs)

NOTE: This document applies to Exelon Nuclear, ComEd, and BSC. The format of this procedure incorporates format and content requirements from several business units, and does not fully conform to the Exelon Nuclear, ComEd, and BSC procedure formats. In addition, the NPIRs are a standalone document that are applicable to transmission entities outside of Exelon and therefore does not include typical Exelon header or footer designations.

1. The attached provides the current revision of the station specific mutually agreed to Nuclear Plant Interface Requirements for Byron Station Units 1 and 2.
2. In accordance with NERC Standard NUC-001, Exelon Nuclear shall prepare and maintain a current NPIRs document for Byron Station Units 1 and 2. (NERC NUC-001, Requirement R1)
3. Initiating a revision to the station specific NPIRs is the responsibility of Exelon Nuclear. The process for initiating, tracking, and implementing revisions to the station specific NPIRs is the responsibility of the Exelon Nuclear NERC Compliance Contact as is outlined in LS-AA-129.
4. If there are no changes to this document other than a revision to the NPIRs that is processed in accordance with LS-AA-129, this document is only required to be issued for final signatures on Attachment 1. No additional procedure review is necessary since the NPIRs are reviewed and approved outside of the Exelon Nuclear and BSC procedure review process.
5. The NPIRs attached to WC-BY-8003-1001 are a standalone document that are reviewed and approved in accordance with the process outlined in LS-AA-129. Any changes to the NPIRs shall be coordinated through the NERC Compliance contacts in ComEd, PJM and Exelon Nuclear.
6. The Nuclear Plant Generator Operator (NPGO) is Exelon Generation Company, LLC – Exelon Nuclear.
7. The Transmission Entities associated with the Byron NPIRs are as follows:
   - PJM Interconnection, LLC (PJM)
   - Commonwealth Edison Company (ComEd)

8. PJM performs the following NERC registered functions for Byron Station: Balancing Authority, Reliability Coordinator, Planning Authority, Transmission Planner, Transmission Service Provider and Transmission Operator.

    - PJM Manual 39, "Nuclear Plant Interface Coordination," constitutes the NUC-001 Agreement between PJM and Exelon Nuclear for Byron Station.

9. ComEd performs the following NERC registered function for Byron Station: Transmission Owner. ComEd owns the Byron Station Switchyard.

    ComEd and Exelon Nuclear have three procedures that constitute the NUC-001 Agreement(s) between ComEd and Exelon Nuclear for Byron Station. WC-BY-8003-1001 supports the interface procedures listed below. ComEd and Exelon Generation are members of PJM Interconnection (PJM) and are required to comply with PJM Manual M39. The most current NPIRs are also attached to PJM Manual 39. In addition, ComEd and Exelon Nuclear may rely on other procedures or agreements to satisfy the NERC NUC-001 and Plant Specific NPIR requirements.

    - OP-AA-108-107-1002, "Interface Procedure between BGE/ComEd/PECO and Exelon Generation (Nuclear/Power) for Transmission Operations"
    - WC-AA-8000, "Interface Procedure between BGE/ComEd/PECO and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities"
    - WC-AA-8003, "Interface Procedure between BGE/ComEd/PECO and Exelon Generation (Nuclear/Power) for Design Engineering and Transmission Planning Activities"

This document, along with other interface procedures and Affiliate Level Arrangements (ALAs), constitute the Interface Agreement between ComEd and Exelon Generation. Revisions to this Procedure require approval and signature by a management representative for each of the entities listed below.

Maria J. Lubash for Erika Bonelli | 8/8/18

ComEd Director Trans & Substation Work Management (Erika Bonelli) | Date

William J. Gannon | 8/8/18

ComEd Director Trans & Substation Engineering (William Gannon) | Date

John M. Garavaglia | 8/8/18

ComEd Director Trans Ops & Planning (John Garavaglia) | Date

David J. Carlson | 8/8/2018

ComEd NERC Compliance (David Carlson) | Date

This document, along with other interface procedures and Affiliate Level Arrangements (ALAs), constitute the Interface Agreement between ComEd and Exelon Generation. Revisions to this Procedure require approval and signature by a management representative for each of the entities listed below.

Roman Gesior — 8/7/18

Exelon Nuclear Engineering CFAM
(Roman Gesior) — Date

8-7-18

Exelon Nuclear NERC Compliance
(Alison Mackellar) — Date

Christopher A. Cote for — 8.7.18

Site Engineering Director
(Charles Wesley Keller) — Date

NUCLEAR PLANT INTERFACE REQUIREMENTS (Revision 5, 8/10/2018)
NERC, NUC-001 COMPLIANCE

Station: Byron Station, Units 1 and 2

Operating Company: Exelon Generation Company, LLC (Nuclear Plant Generator Operator ("NPGO") for NUC-001)

Transmission Zone(s)/Owner: ComEd (Transmission Entity ("TE") for NUC-001)

Reliability Coordinator: PJM (Transmission Entity ("TE") for NUC-001)

Requirement Categories:

1. Operational requirements

Offsite Power Sources required to comply with General Design Criteria ("GDC") 17:

The preferred power system is considered as having three major sections, each of which must provide two physically separate and electrically independent circuit paths between the onsite power system and the transmission network (the transmission network excludes the station switchyard). The three sections are:

1. The transmission lines entering the station switchyard from the transmission network.
2. The station switchyard. (A common switchyard is allowed by GDC 17).
3. The overhead transmission lines, system auxiliary transformers (SATs), and buses between the switchyard and the onsite power system.

Two physically separate and electrically independent circuits are provided for each unit, one via the unit's assigned SATs and the other from the SATs of the other unit.

Therefore, the two offsite power sources, are as follows:

a. SAT 142-1 and SAT 142-2 which supply Unit 1 (normal) and Unit 2 (reserve) with auxiliary power from the 345kV switchyard.
b. SAT 242-1 and SAT 242-2 which supply Unit 2 (normal) and Unit 1 (reserve) with auxiliary power from the 345kV switchyard.

The capacity of each offsite power supply shall be sufficient to operate the loads required for safe shutdown of both units with a Loss of Coolant Accident ("LOCA") in one unit and a simultaneous safe shutdown of the other unit.

- Capacity of the source connected to SAT 142-1 and SAT 142-2 shall be a minimum of 144 MVA at 0.90 power factor (p.f.).
- Capacity of the source connected to SAT 242-1 and SAT 242-2 shall be a minimum of 144 MVA at 0.90 power factor (p.f.).

For the offsite power sources to be considered operable and electrically independent, two different transmission sources (transmission lines from different origins) must be provided to the SATs. The two independent transmission sources and either transmission source by itself must be capable of supplying a total of 144 MVA at 0.90 power factor (p.f.).

The switchyard is supplied from five transmission sources:

a. Byron-Cherry Valley (L0621) 345 kV Line
b. Byron-Cherry Valley (L0622) 345 kV Line
c. Byron-Wempletown (L0624) 345 kV Line
d. Byron-Lee County (L0627) 345 kV Line
e. Byron-Wayne (L0626) 345 kV Line

Because the two Byron-Cherry Valley (L0621 & L0622) 345kV Lines share a common transmission tower and the Byron-Wayne (L0626) 345kV Line runs in close proximity to the two Byron-Cherry Valley (L0621 & L0622) 345 kV Lines, they cannot be considered independent; therefore, at least one of the transmission sources must be the Byron-Wempletown (L0624) 345 kV Line or the Byron-Lee County (L0627) 345 kV Line.

The Transmission Operator (PJM) shall notify Exelon Generation Company, L.L.C of Transmission System Emergencies via the PJM All-Call System and PJM Website, consistent with PJM Actions documented with PJM Emergency Operations Manual (M13). Exelon Generation Dispatch shall notify the station or the Exelon Nuclear Duty Officer of the following conditions to allow the station to assess the operability of the offsite power sources in support of the station Technical Specifications and also to allow the station to assess risk that may result from proposed or on-going maintenance in support of station commitments to 10CFR50.65 (Nuclear Maintenance Rule):

1. Transmission System Emergencies, as listed below and defined in PJM Manual M-13, applicable to Byron. Note: The following are communicated by PJM to Exelon Generation Company, L.L.C.

    a. Capacity Emergencies

    b. Weather/Environmental Emergencies

    c. Transmission Security Emergencies

PJM shall communicate localized transmission emergencies that could impact the Byron Station through the ComEd Transmission Entity to the Exelon Nuclear Duty Officer. PJM shall have direct communication with the ComEd Transmission Entity when this notification is required.

The ComEd Transmission Entity must notify the station of the following conditions to allow the station to assess the operability of the offsite power sources in support of the station Technical Specifications and also to allow the station to assess risk that may result from proposed or on-going maintenance in support of station commitments to 10CFR50.65 (Nuclear Maintenance Rule):

1. Automatic or manual operation of system components that result in transmission lines connected to the Byron switchyard being out of service. This includes the circumstance in which the Byron-Lee County (L0627) 345kV Line is out of service (i.e., not capable of supplying 144 MVA at 0.90 power factor (p.f.)) as a result of the Lee County-Nelson (L15501) 345kV Line being out of service.

2. Contingent or actual voltage violations existing at the station interconnection points.

3. Prior to planned and emergent switching in the Byron switchyard. For emergency switching,

notification to the station shall occur after the switching if it is not possible to notify the station prior to the switching.

4. Switchyard equipment failures or emergent equipment conditions requiring immediate action.

The Byron Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Byron Unit 1
Normal Low (actual voltage evaluations) – 341.4kV (.9896 pu)
Emergency Low (contingency voltage evaluations) – 341.4kV (.9896 pu)

345kV: Byron Unit 2
Normal Low (actual voltage evaluations) – 351.2kV (1.0180 pu)
Emergency Low (contingency voltage evaluations) – 351.2kV (1.0180 pu)

Notes: It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

Frequency requirements: The station has the following under or over frequency protection that would initiate a trip of the generating units or the offsite power sources:

1) Byron has under frequency protection on the 6.9kV buses for the RCPs (Reactor Coolant Pumps) set at 57Hz with 6 cycles time delay (results in trip of unit generator). In addition, there is generator over frequency protection (in coincidence with a low load) set at 62.5Hz with 6 cycles time delay (results in trip of unit generator).

A state estimator and real time contingency analysis program shall be used to monitor the Byron voltage limits. Single contingencies analyzed must include the trip of a Byron unit (each unit separately) and the trip of transmission facilities impacting the Byron voltage limits. All contingency voltage limit violations shall be communicated to Exelon Nuclear within 15 minutes regardless of whether the contingency is the Byron unit or a transmission facility. The communication shall include whether the contingency causing the limit violation is the Byron unit.

Actual voltage limit violations shall be communicated to Exelon Nuclear promptly.

If both the Transmission Operator (PJM) and ComEd Transmission Entity lose the capability to perform state estimation or real time contingency analysis to support monitoring the Byron voltage limits, Exelon Nuclear shall be notified. If Exelon Nuclear is notified that the Transmission Operator (PJM) and ComEd Transmission Entity has lost their state estimator and real time contingency analysis capability, the Transmission Operator (PJM) and ComEd Transmission Entity shall support Byron and provide an assessment when requested and as system conditions permit of the current condition of the grid based on the tools that the Transmission Operator (PJM) and ComEd Transmission Entity has available.

The station shall be notified of transmission system emergencies and emergent grid issues that may affect unit or transmission system reliability as soon as system conditions permit. These notifications shall include conditions that potentially impact the station generators and or the station offsite power sources as defined above.

2. Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Byron switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Byron voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Byron requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study criteria violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. For study violations that are beyond applicable PJM criteria, Exelon Nuclear will determine if any further action is required and respond to PJM. The following Byron requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:
Refer to Section 1 for the requirements. Note: For the purposes of the planning studies only the Byron unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:
Byron generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

a) A three-phase line fault with normal clearing of the line protective systems.

b) A phase-to-ground fault with normal clearing and with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.

c) A double line tower fault.

d) A phase-to-ground fault during planned transmission line maintenance outages.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Byron generators, the Byron switchyard, or the lines connecting the Byron switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

3. Design Criteria

DESIGN BASES - UFSAR
The following design bases are applied to the design of the onsite and offsite power systems:

There is a set of two normally connected system auxiliary transformers for each unit. Each one of the system auxiliary transformers normally supplies one division. The set of two system auxiliary transformers is sized to provide the required power of the unit under startup, full load, safe shutdown, and Design Basis Accident (DBA) load conditions.

In the event of a failure of one system auxiliary transformer, removable links (within the station) can be relocated to connect the other system auxiliary transformer to supply both divisions. This provides flexibility in the auxiliary power system; however, operation of the plant in this configuration with one SAT out of service is limited to the requirements set forth in Section 3.8 of the Technical Specifications. Each set of system auxiliary transformers is capable of supplying the DBA loads of both divisions of one unit and the safe shutdown loads of both divisions of the other unit simultaneously.

4. Restoration Requirements

Restoration of Offsite Power:

a) Byron Units 1 & 2 "station blackout" coping time is 4 hours. The transmission system restoration process shall have provisions to consider and prioritize the requirements of a nuclear power plant that has lost both offsite and onsite AC power.

b) Restoration of offsite power to one of the offsite power sources shall be as soon as possible regardless of whether the Byron units were operating prior to the system disturbance causing the loss of offsite power. For the purposes of restoration, one of the following sources must be restored:

1) SAT 142-1/SAT 142-2 supplying Unit 1 and Unit 2 (via internal crosstie) with auxiliary power from the 345kV switchyard.
2) SAT 242-1/SAT 242-2 supplying Unit 2 and Unit 1 (via internal crosstie) with auxiliary power from the 345kV switchyard.

c) A single restored offsite power source shall be capable of supplying the following load: 86.0 MVA at 0.90 power factor (p.f.) except as specified in section 4d below.

d) For the purpose of determining the TO/TOP zonal blackstart requirements for critical load, as defined in PJM Manual 36, the minimum required load capability of an off-site power source, in order to maintain the unit in safe shutdown and to allow the transition to cool down using the main condenser, is 40.5 MWs and 18.5 MVARs for Byron Unit 1 and 31.7 MWs and 14.4 MVARs for Byron Unit 2. The load capability also allows transition from natural circulation. Providing offsite power for Byron Units 1 and 2 is a restoration priority. The target restoration time of four hours is to be a drilled upon goal - however it is not a requirement since restoration times will be dependent on the nature of the Loss of Offsite Power (LOOP) event.

e) The voltage limit established within the state estimator for the restored offsite source shall be as stated in Section 1 with the clarification that only the "Normal Low" limit is to be applied if the Byron generating units are not in operation.

f) For restoration of an offsite power source the transmission system frequency must be stable. Stable is defined as 59.75 – 61.00 Hz.

g) Transmission Owners must communicate to Exelon Nuclear the anticipated restoration time for offsite power.

Re-start of a Byron unit following a loss of offsite power and a unit trip:

a) The Byron Technical Specifications require two separate and independent off site power sources be operable prior to bringing a unit back online following a unit trip. For the purposes of restart, the following offsite power sources must be restored:

   1) SAT 142-1/SAT 142-2 supplying Unit 1 and Unit 2 (via internal crosstie) with auxiliary power from the 345kV switchyard.
   2) SAT 242-1/SAT 242-2 supplying Unit 2 and Unit 1 (via internal crosstie) with auxiliary power from the 345kV switchyard.

b) Each restored offsite power source shall be capable of supplying the following load: 86.0 MVA at 0.90 power factor (p.f.).

c) The voltage limit requirements for the restored offsite sources shall be as stated in Section 1.

d) For restoration of the offsite power sources the transmission system frequency must be stable. Stable is defined as within the frequency operating criteria specified in PJM Manual M-12 "Balancing Operations".

e) Two independent 345 kV transmission lines must be in service as stated in Section 1.

5. Nuclear Plant Switchyard Equipment Maintenance Requirements

Byron is responsible for complying with the NRC Maintenance Rule. "NRC Maintenance Rule" shall mean the NRC rules and regulations set forth in 10CFR50.65, as they may be amended from time to time. 10CFR50.65 provides the NRC requirements for monitoring the effectiveness of maintenance at Nuclear Power Plants. The Maintenance Rule requires the <u>nuclear plant licensee</u> to monitor the performance and condition of structures, systems, or components (SSCs) against licensee established goals in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended function. The following requirements support the station implementation of the Maintenance Rule.

Nuclear plant switchyard equipment includes all switchyard equipment up to and including the transmission line disconnects, not the transmission lines leaving the station.

When the ComEd Transmission Entity becomes aware of a failure of a component in the Byron switchyard, Byron shall be promptly notified.

The ComEd Transmission Entity shall maintain records concerning preventative and corrective maintenance activities performed by the ComEd Transmission Entity on ComEd Transmission Entity components in the Byron switchyard.

The ComEd Transmission Entity shall provide a periodic report to Byron for review of switchyard corrective and preventative maintenance. For failures of Byron switchyard equipment, the ComEd Transmission Entity shall provide on request the cause of the failure and the extent of condition within the Byron switchyard in support of NRC Maintenance Rule evaluations.

Exelon Nuclear and the ComEd Transmission Entity have mutually agreed to the scope and frequency of Preventative and Predictive Maintenance to be performed in the Byron Switchyard. The ComEd Transmission Entity shall notify Byron and obtain concurrence from Byron for any planned and actual changes to the scope or frequency of this maintenance.

In accordance with the NRC Maintenance Rule, Byron analyzes performance of switchyard components and will notify the ComEd Transmission Entity if a performance improvement plan is required. The ComEd Transmission Entity and Byron shall work cooperatively to develop and implement a mutually agreeable performance improvement plan.

Conduct of Maintenance in the station switchyards:

a) Byron shall be notified prior to performing any work in the switchyard.
b) Byron shall be notified of emergent work.
c) Byron shall be notified of failures to meet acceptance criteria.
d) Byron shall be notified upon completion of work in the switchyards.

6. Communication Requirements

Operations:
Communication requirements for Operational issues shall be as defined in Section 1 above. In addition, the station shall communicate to the ComEd Transmission Entity scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages, transformer tap changers used for maintaining post trip voltages taken to manual).

Planning
Communication requirements for Planning issues shall be as defined in Section 2 above.

Short Circuit Calculations
Byron is responsible for the short circuit calculations for Byron equipment. The responsible ComEd Transmission Entity shall provide to Byron when requested the available short circuit capability at the points of interconnection.

Switchyard and Transmission System Modifications (Transmission Owner responsibility based on transmission asset ownership)
Information regarding modifications to the Byron switchyard and the interconnected transmission system up to and including the first circuit breaker from Byron Station shall be provided prior to implementation so that Byron may evaluate the potential impact of such modifications. This shall include information on modifications that adversely impact the independence of transmission lines entering the Byron switchyard and the L15501 line (i.e., designs that would add or modify a transmission facility such that a failure could result in the loss of more than one line). For example, a new transmission line routed over L0621 line and L0624 line could potentially impact the independence of the lines based on a postulated tower failure. Modifications to components in the remote substation to Byron and the interconnected transmission lines that do not impact component function or transmission line independence are excluded from this requirement.

Maintenance Activities (Transmission Owner responsibility based on transmission asset ownership)
Communication requirements for Maintenance Activities shall be as defined in Section 5 above. In addition the following notifications are required.

a) Scheduled transmission system equipment work/outages and changes in planned work/outages shall be communicated to Byron. This shall include Byron switchyard equipment work/outages, work/outages on the transmission lines entering the Byron switchyard, and component outages at the first substation remote from Byron that would prevent power flow on a transmission line connected to the Byron switchyard. Scheduled transmission system equipment outages which cause the L15501 line being out of service shall also be communicated.

Revision - Date	Summary of Revision(s)
Revision 0 3/23/10	Initial issuance
Revision 1 7/15/11	Revised language related to planning study results
Revision 2 2/28/13	Increased internal load requirements for Byron Station Units 1 and 2 affecting both units Voltage Operating Limits, made changes to the planning study stability requirements and added paragraph at the end of Section 1 regarding notification requirements.
Revision 3 9/1/15	Revised and added language to incorporate shutdown load information and addition of a power factor (p.f.) to source load capability values.
Revision 4 4/7/17	Revised to add language to incorporate addition of the Byron-Wayne (L0626) 345 kV Line
Revision 5 8/10/18	Revised to implement revisions to Byron Station Unit 2 minimum voltage limit due to extended operation of a single System Auxiliary Transformer (SAT) configuration.

Byron Station, Units 1 and 2

License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 10

BYRON STATION UFSAR TABLE 8.3-5, "LOADING ON 4160-VOLT ENGINEERED SAFETY FEATURES (ESF) BUSES"

TABLE 8.3-5

LOADING ON 4160-VOLT ESF BUSES (y)

LOADING ON 4160-VOLT ESF BUSES ASSUMING:
1. TOTAL LOSS OF PLANT OFFSITE POWER
2. UNIT 1 IN LOCA CONDITION
3. UNIT 2 IN HOT STANDBY CONDITION
4. ALL 4 DIESEL-GEN. SETS START

	START SEQUENCE (SEC) AFTER EDG START SIGNAL (a)	NUMBER INSTALLED		MOTOR RATED HP	NUMBER OF CONTINUOUSLY ENERGIZED LOADS DURING INITIAL PERIOD			
					UNIT 1		UNIT 2	
		UNIT 1	UNIT 2		ESF DIV. 11	ESF DIV. 12	ESF DIV. 21	ESF DIV. 22
A. 4-kV Loads (b)								
1. 4160-V/480-V Unit Substations (p)	10	4	4	-	2	2	2	2
2. Centrifugal Charging Pump	12	2	2	600	1	1	1	1
3. Safety Injection Pump	17	2	2	400	1	1	-	-
4. Residual Heat Removal Pump	22	2	2	400	1	1	-	-
5. Control Room Refrigeration Unit (e) (s)	27	2	0	461	1	1	-	-
6. Containment Spray Pump	27/52(i)	2	2	600	1	1	-	-
7. Component Cooling Pump	32	2	2	450	1	1	1	1
8. Essential Service Water Pump	37	2	2	1250	1	1	1	1
9. Motor Driven Auxiliary Feedwater Pump (c)	47	1	1	1250	1	-	1	-
10. Auxiliary Building Supply Fan	(j)	2	2	350	0	0	0	0
11. Auxiliary Building Exhaust Fan	(j)	2	2	500	0	0	0	0

TABLE 8.3-5 (Cont'd)

LOADING ON 4160-VOLT ESF BUSES (y)

LOADING ON 4160-VOLT ESF BUSES ASSUMING:
1. TOTAL LOSS OF PLANT OFFSITE POWER
2. UNIT 1 IN LOCA CONDITION
3. UNIT 2 IN HOT STANDBY CONDITION
4. ALL 4 DIESEL-GEN. SETS START

	START SEQUENCE (SEC) AFTER EDG START SIGNAL (a)	NUMBER INSTALLED		MOTOR RATED HP	NUMBER OF CONTINUOUSLY ENERGIZED LOADS DURING INITIAL PERIOD			
					UNIT 1		UNIT 2	
		UNIT 1	UNIT 2		ESF DIV. 11	ESF DIV. 12	ESF DIV. 21	ESF DIV. 22
B. 480-V Switchgear Loads (d)								
1. Containment Cooling Fan (RCFC) (n)		4	4	100/150	2 (low)	2 (low)	2 (high)	2 (high)
2. Control Room HVAC System Supply Fan (e)		2	0	125	1	1	-	-
3. Diesel Gen. Room Vent Fan		2	2	125	1	1	1	1
4. Auxiliary Bldg. Charcoal Booster Fan (h)		3	3	75	0	1	1	1
5. Turbine Bearing Oil Pump (u)		1	1	100	-	0	-	1
6. ESW Cooling Tower Fan - *See note (m)		4	4	150/37.5	*	*	*	*
7. 125-Vdc Battery Charger		2	2	50 kVA	1	1	1	1
8. Cubicle Cooler Fan for Diesel Driven AFW Pump (r)		1	1	75	-	0	-	0
9. Deep Well Pump (u)		2	0	125	0	0	-	-
C. 480-V MCC Loads (d)								
1. Cubicle Cooler Fans for ECCS Loads (w)		28	28	3	14	14	6	6
2. F.H. Bldg. Charcoal Booster Fan		2	0	25	1	0	-	-
3. Control Room HVAC System (e)								
a. Return Fan		2	0	40	1	1	-	-
b. Make-up Air Filter Unit Fan		2	0	25	1	1	-	-
c. Make-Up Air Filter Unit Electric Heating Coil (t)		2	0	27.2 kW	1	1	-	-
d. Chilled Water Pump		2	0	40	1	1	-	-

TABLE 8.3-5 (Cont'd)

LOADING ON 4160-VOLT ESF BUSES (y)

LOADING ON 4160-VOLT ESF BUSES ASSUMING:
1. TOTAL LOSS OF PLANT OFFSITE POWER
2. UNIT 1 IN LOCA CONDITION
3. UNIT 2 IN HOT STANDBY CONDITION
4. ALL 4 DIESEL-GEN. SETS START

	START SEQUENCE (SEC) AFTER EDG START SIGNAL (a)	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	MOTOR RATED HP	NUMBER OF CONTINUOUSLY ENERGIZED LOADS DURING INITIAL PERIOD UNIT 1 ESF DIV. 11	UNIT 1 ESF DIV. 12	UNIT 2 ESF DIV. 21	UNIT 2 ESF DIV. 22
4. Diesel Oil Storage Room Exhaust Fan		4	4	3	1	1	1	1
5. Diesel Gen. Room Exhaust Fan (w)		2	2	3	0	0	0	0
6. Elec. Equip. Room Vent Fan (f)		1	1	50	-	1	-	1
7. Battery Room Exhaust Fan		2	2	3	1	1	1	1
8. ESF Switchgear Room Vent. Fan		2	2	50	1	1	1	1
9. Lower (el. 439'-0") Cable Spreading Room Vent Fan (g)		1	1	40	-	1	-	1
10. Essential Lighting		8	4	15 kVA	3	5	2	2
11. Diesel Oil Transfer Pump		4	4	2	2	2	2	2
12. D.G. Air Compressor (x)		4	4	15	0	0	0	0
13. Lube Oil Pumps for ECCS loads		7	7	2 (v)	0	0	0	0
14. 120-Vac Instrument Bus Inverter		4	4	10 kVA (z)	2	2	2	2
15. 120-Vac Instrument Bus Transformer		4	4	10 kVA	0	0	0	0
16. Control Room Refrig. Unit Oil Pump		2	0	1.5	1	1	-	-
17. Control Room Refrig. Unit Purge Compressor		2	0	2	1	1	-	-
18. D.G. Jacket Water Circ. Pump (x)		2	2	5	0	0	0	0
19. D.G. Jacket Water Heater (x)		2	2	18 kW	0	0	0	0
20. D.G. Oil Heaters (x)		2	2	12 kW	0	0	0	0
21. D.G. Pre-Lube Oil Pump (x)		2	2	15	0	0	0	0
22. D.G. Space Heater (x)		2	2	4.5 kW	0	0	0	0

TABLE 8.3-5 (Cont'd)

	START SEQUENCE (SEC) AFTER EDG START SIGNAL (a)	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	MOTOR RATED HP	NUMBER OF CONTINUOUSLY ENERGIZED LOADS DURING INITIAL PERIOD UNIT 1 ESF DIV. 11	UNIT 1 ESF DIV. 12	UNIT 2 ESF DIV. 21	UNIT 2 ESF DIV. 22
23. Hydrogen Recomb. Pwr & Contrl		2	0	60 kW	0	0	-	-
24. Cooling Tower SWGR Rm. Vent Fan		2	2	5	1	1	1	1
25. 120/208-V Distribution Panels		11	10	22.5 kVA	5	6	5	5
26. Refueling Water Purification Pump		2	0	20/15	0	0	-	-
27. Misc. Elec. Equipment Room Vent Fan		2	2	5/7.5	1	1	1	1
28. Hydrogen Monitor Analyzer Panel		2	2	2.5	0	0	0	0
29. Diesel Driven AFW Pump Jacket Water Heater (x)		1	1	5 kW	-	0	-	0
30. ESW Cooling Tower Valve Chamber Heater		2	2	10 kW	1	1	1	1
31. ESW Cooling Tower Substation Unit Heater		2	2	25 kW	1	1	1	1
32. ESW Cooling Tower Chem. Tank Room Heater		0	2	10 kW	-	-	-	2
33. ESW Cooling Tower Chem. Tank Room Exh. Fan		0	1	0.5	-	-	-	1
34. ESW Cooling Tower Acid Pump House Heater		2	0	10 kW	-	2	-	-
35. ESW Cooling Tower Acid Pumps		2	2	1.5 kVA	-	2	-	2
36. ESW Cooling Tower Deep Anode Cathodic Protection		0	1	12 kVA	-	-	1	-
37. Valves (k)		-	-	-	-	-	-	-
38. Other loads (1)		-	-	-	-	-	-	-

TABLE 8.3-5 (Cont'd)

NOTES:

a) Start times reflect 10 seconds start time for the diesel generator, 2 seconds for the bus voltage relaying interlock to reenergize the sequencer logic and programmed sequence time delay for major loads.

b) Loads are applied automatically in sequence as indicated.

c) The Train A auxiliary feedwater pump is motor driven powered from Division 11/21 ESF distribution. The B Train auxiliary feedwater pump is diesel driven.

d) Loads are energized automatically upon restoration of bus voltage.

e) Consists of two 100% systems. For purposes of operating Unit 2 during unit outage on Unit 1, the 4160-volt cross-ties can be closed to associate the control room HVAC systems with Unit 2, the operating unit.

f) The electrical equipment room vent fans serve Division 2 equipment only. Corresponding Division 1 equipment is served by ESF switchgear room vent fan.

g) Cable spreading room vent fans serve Division 2 equipment only.

h) Three out of six auxiliary building charcoal booster fans will start on SI signal from either Unit, but only two are required.

i) If containment spray actuation is not required at 27 seconds after a LOCA or steam line break, automatic start of containment spray pump is blocked until all other loads are sequenced on to the diesels (i.e., 52 seconds after the diesel generator start signal).

j) Applied manually by operator 2 hours subsequent to LOCA.

k) Loads are considered intermittent.

l) See UFSAR Section 8.3.1.1.2.2 for definition of "other loads".

m) For the scenario identified for Table 8.3-5, the Ultimate Heat Sink Design Basis Analysis assumes that any two ESW cooling tower fans may be unavailable and that the remaining ESW cooling towers fans are operating at high speed to remove the heat load. The ESW cooling tower fans are controlled via manual operator actions, therefore, the specific fans operating are determined by the operator's discretion.

n) Containment fan coolers (RCFC) operate at high speed during normal plant operation and are energized in high speed upon restoration of bus voltage if no safety injection signal is present. The RCFC will start at low speed 20 seconds after a safety injection signal. The 20 second time delay is developed in the breaker control circuit and will continue independent of the restoration of AC power by the diesel generators so start time is 20 seconds from SI signal and not EDG start.

p) 4160-V/480-V unit substations will be energized as soon as the bus feed breaker to the diesel generator is closed.

r) Diesel-driven AFW pump cubicle cooler fan not required until pump shuts down.

s) Control room refrigeration units have inherent time delays before the chillers will start, which are:

1. 51 ± 4 seconds following an ESF actuation signal when the chiller is in either local or remote and is in standby.
2. 150 ± 5 seconds after the bus has been restored when the chiller is in either local or remote and was running.

t) Control room HVAC makeup heating coil - Division 11 and Division 12 will not operate simultaneously.

TABLE 8.3-5 (Cont'd)

NOTES (cont'd):

u) The turbine bearing oil pump and deep well pump are powered from the Class 1E 480-V switchgear, however, they automatically trip on a safety injection signal concurrent with a loss of offsite power.

v) AF and CV pump lube oil pumps are rated at 2 HP, SX pump lube oil pump is rated at 0.5 HP.

w) The motor-driven auxiliary feed pump on Division 11 (21) does not have cubicle coolers.

x) This load is not required when the diesel is running.

y) Current actual EDG loading is determined using load flow studies from approved AC system analytical software. The highest EDG loading during a LOCA coincident with a LOOP is 5229 kW (5763 kVA) for the 1A EDG during the initial loading period. The highest EDG loading for a normal shutdown coincident with a LOOP is 4581 kW (5095 kVA) for the 1A EDG.

Diesel-Gen. 2 Hr. Rating (kW/kVA) 6050/7563
Diesel-Gen. 2000 Hr. Rating (kW/kVA) 5935/7419
Diesel-Gen. Continuous Rating (kW/kVA) 5500/6875

z) Instrument Bus Inverters are rated at 10 KVA. However, Instrument Bus Inverter loading is administratively limited to ≤ 7.5 KVA.