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ComEd

January 20, 2000

U.S. Nuclear Regulatory Commission
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Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

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

Subject: Request for Amendment to Technical Specifications
Extension of Allowable Completion Times and Surveillance Requirement Change for Emergency Diesel Generators

In accordance with 10 CFR 50.90, Commonwealth Edison (ComEd) Company proposes changes to Appendix A, Technical Specifications of Facility Operating Licenses NPF-72, NPF-77, NPF-37 and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively.

The proposed changes to Technical Specifications (TS) Section 3.8.1 "AC Sources – Operating," will extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG). The changes are being proposed to support on-line maintenance and overhaul of the EDGs. The current Completion Times for restoration of an inoperable EDG are insufficient to support the required maintenance and post-maintenance testing windows. In conjunction with this proposed change, a new Required Action is proposed to be incorporated into the TS to verify the operability of the opposite unit EDGs while the affected EDG is inoperable. This action ensures the availability of the remaining alternating current (AC) power sources to power the affected Engineered Safety Feature (ESF) bus. In addition, the TS Surveillance Requirement (SR) corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) will be revised to allow the SR to be performed during Modes 1 and 2. This endurance run could then be performed as a post-maintenance verification test subsequent to the EDG overhauls when necessary.

These proposed changes will provide operational flexibility allowing more efficient application of plant resources to safety significant activities. These proposed changes will allow performance of periodic EDG overhauls and post-maintenance testing on-line, reducing plant refueling outage duration and improving EDG availability during shutdown.

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The justification for the change to the EDG Completion Time is based upon a risk-informed, deterministic evaluation consisting of three main elements: 1) the availability of offsite power via the System Auxiliary Transformer (SAT) and unit cross-tie, 2) verification that the opposite unit EDGs and offsite power source are operable, and 3) implementation of a Configuration Risk Management Program (CRMP) while the EDG is in an extended Completion Time. These elements provide the basis for the requested TS change by providing a high degree of assurance of the capability to provide power to the ESF buses during the EDG extended Completion Time. The NRC recently approved similar requests for several other stations including a request by the Perry Nuclear Plant Unit 1 when it issued Amendment 99 to Facility Operating License No. NPF-58 via letter dated February 24, 1999.

Implementation of these proposed changes will require completion of plant modifications, implementation of a CRMP, and procedure changes. The plant modifications are required to resolve an existing identified flooding vulnerability. A letter providing additional details and the installation schedule will be submitted to the NRC for information by April 3, 2000. The CRMP and procedure changes are necessary to manage the risk impact of performing EDG maintenance on-line.

ComEd requests approval of this proposed TS change by August 1, 2000 to support procedural changes and work planning prior to the Byron Station, Unit 1, and Braidwood Station, Unit 2, Fall 2000 refueling outages.

This change request is subdivided as follows.

1. Attachment A gives a description and safety analysis of the proposed changes.
2. Attachments B-1 and B-2 include the marked-up TS pages and Bases pages with the requested changes indicated for Braidwood and Byron Stations. Attachments B-3 and B-4 provide the typed TS pages and Bases pages with the proposed changes incorporated.
3. Attachment C describes our evaluation performed using the criteria in 10 CFR 50.91(a)(1), and provides information supporting a finding of no significant hazards consideration using the standards in 10 CFR 50.92(c).
4. Attachment D provides information supporting an Environmental Assessment.
5. Attachment E provides a summary of the Byron and Braidwood Station Probabilistic Risk Assessment.

These proposed changes have been reviewed by the Plant Operations Review Committee and the Nuclear Safety Review Board in accordance with the Quality Assurance Program.

ComEd is notifying the State of Illinois of this request for changes to the TS by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions relative to this submittal, please contact Mr. R. V. Fairbank at (630) 663-3052.

Respectfully,

R. M. Krich
Vice President – Regulatory Services

Attachments:	Attachment A,	Description and Safety Analysis for Proposed Changes
	Attachment B-1,	Marked-up Pages for Proposed Changes, Braidwood Station
	Attachment B-2,	Marked-up Pages for Proposed Changes, Byron Station
	Attachment B-3,	Incorporated Proposed Changes, Braidwood Station
	Attachment B-4,	Incorporated Proposed Changes, Byron Station
	Attachment C,	Information Supporting A Finding of No Significant Hazards Consideration
	Attachment D,	Information Supporting An Environmental Assessment
	Attachment E,	Summary of Byron and Braidwood Station Probabilistic Risk Assessment

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Braidwood Station
NRC Senior Resident Inspector – Byron Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

STATE OF ILLINOIS	)	
COUNTY OF DUPAGE	)	
IN THE MATTER OF	)	
COMMONWEALTH EDISON (COMED) COMPANY	)	Docket Numbers
BRAIDWOOD STATION UNITS 1 AND 2	)	STN 50-456 AND STN 50-457
BYRON STATION UNITS 1 AND 2	)	STN 50-454 AND STN 50-455

SUBJECT: **Request for Amendment to Technical Specifications, to Facility Operating Licenses, Emergency Diesel Generators, Completion Time Extension and Surveillance Requirement Change**

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

R. M. Krich
Vice President - Regulatory Services

Subscribed and sworn to before me, a Notary Public in and for the State above named, this 20 day of January 20 00

OFFICIAL SEAL
JEFFERY A BATARA
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES:02/24/02

Notary Public

ATTACHMENT A

PROPOSED CHANGES TO TECHNICAL SPECIFICATIONS FOR BYRON STATION, UNITS 1 AND 2 BRAIDWOOD STATION, UNITS 1 AND 2

DESCRIPTION AND SAFETY ANALYSIS FOR PROPOSED CHANGES

SUMMARY OF PROPOSED CHANGES

In accordance with 10 CFR 50.90, Commonwealth Edison (ComEd) Company is requesting changes to Appendix A, Technical Specifications (TS) of Facility Operating License Nos. NPF-72, NPF-77, NPF-37 and NPF-66, for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively.

The proposed changes will extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG). These changes are being proposed to support on-line maintenance and overhaul of the EDGs. The current Completion Times for restoration of an inoperable EDG are insufficient to support the required maintenance and post-maintenance testing windows. A new Required Action is also proposed to be incorporated into the TS to verify the operability of the opposite unit EDGs while the affected EDG is inoperable. This action ensures the availability of the remaining AC power sources to the affected Engineered Safety Feature (ESF) bus. In addition, the Surveillance Requirement (SR) corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) would be revised to allow the SR to be performed during operational Modes 1 and 2 (i.e., "Power Operation" and "Startup," respectively). This test could then be performed as a post-maintenance verification test subsequent to the EDG overhauls.

The proposed changes will provide operational flexibility allowing more efficient application of plant resources to safety significant activities. The proposed changes will allow performance of periodic EDG overhauls and post-maintenance testing on-line, reducing plant refueling outage duration and improving EDG availability during shutdown.

The proposed changes are described below. The marked-up and proposed TS pages are shown in Attachments B1-B4.

1 DEFINITION OF THE PROPOSED CHANGE

1.1 Technical Specification Sections Affected by the Proposed Changes:

TS Section 3.8.1, "AC Sources – Operating," addresses the operability requirement for alternating current (AC) power sources during Modes 1, 2, 3 and 4 (i.e., "Power Operation," "Startup," "Hot Standby," and "Hot Shutdown," respectively). For Condition A, i.e., "One or more (ESF) buses with one required qualified circuit (i.e., Qualified circuits are those that are described in the UFSAR and are part of the licensing basis for the plant.) inoperable," per Required Action A.2, "Restore required qualified circuits a to OPERABLE status," within a COMPLETION TIME of 72 hours AND six days from discovery of failure to meet the TS Limiting Conditions for Operation (LCO). With one required EDG inoperable, the EDG is required to be restored to operable status within 72 hours AND six days from discovery of failure to meet the TS LCO in accordance with the Completion Time of Required Action B.4.

SR 3.8.1.14, which requires performance of the 24-hour EDG endurance run, is modified by Note 2. Note 2 states: "This Surveillance shall not be performed in MODE 1 or 2."

1.2 Bases for the Current Requirements

The current Completion Times associated with inoperable AC power source(s) are 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, "Availability of Electric Power Sources," December 1974, is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., Completion Times) that the NRC considers acceptable if the number of available AC power sources are less than the LCO. Specifically, "if the available ac power sources are one less than the number required by the TS 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." Regulatory Guide 1.93 also states the following: "The operating time limits delineated in regulatory positions C.1 through C.5 are explicitly for corrective maintenance activities only. These operating time limits should not be construed to include preventive maintenance activities that require the incapacitation of any required electric power source. Therefore, per this guide, preventive maintenance should be scheduled for performance during cold shutdown and/or refueling periods."

The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a Design Basis Accident (DBA) occurring during this period. The six-day Completion Time establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the TS LCO.

As described in the bases for SR 3.8.1.14, the reason for Note 2 is that during operation with the reactor critical, performance of the 24-hour EDG endurance run could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

1.3 Description of the Proposed Changes

The proposed changes are as follows.

- Change the required Completion Time for Required Action B.4 of TS Section 3.8.1 "AC Sources – Operating." This change extends the Completion Time for the EDG from "72 hours <u>AND</u> 6 days from discovery of failure to meet LCO," to "14 days <u>AND</u> 17 days from discovery of failure to meet LCO."

- A new Required Action, B.1, was added to "Verify both opposite-unit DGs OPERABLE, "within a required Completion Time of "1 hour AND Once per 24 hours thereafter," to TS Section 3.8.1.
- A new Condition, C, is added, that states "Required Action and associated Completion Time of Required Action B.1 not met." The Required Action C.1 corresponding to Condition C states "Restore DG to OPERABLE status," within a required Completion Time of "72 hours."
- As a commensurate change, resulting from the EDG Completion Time change, change the required Completion Time for Required Action A.2 from "72 hours AND 6 days from discovery of failure to meet LCO," to "72 hours AND 17 days from discovery of failure to meet LCO."
- Conditions and Required Actions are renumbered as necessary due to the addition of the new Required Action B.1 and Condition C.
- SR 3.8.1.14, associated with the 24-hour EDG endurance run is changed to allow performance of this surveillance in any Mode or condition, by deleting Note 2, "This Surveillance shall not be performed in MODE 1 or 2", to SR 3.8.1.14.

1.4 Reason for Proposed Change

The proposed changes are consistent with NRC policy and will continue to provide adequate protection of public health and safety and common defense and security as described below. The changes advance the objectives of the NRC's Probabilistic Risk Assessment (PRA) Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995. for enhanced decision-making and result in a more efficient use of resources and reduction of unnecessary burden. Implementation of this proposed Completion Time extension and removal of the Mode restriction from performance of the SR will provide the following benefits.

- Allow increased flexibility in the scheduling and performance of EDG preventive maintenance.
- Allow better control and allocation of resources. Allowing on-line preventive maintenance, including overhauls, provides the flexibility to focus more quality resources on any required or elected EDG maintenance.
- Avert unplanned plant shutdowns and minimize the potential need for requests for Notice of Enforcement Discretion (NOED). Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve EDG availability during shutdown Modes or Conditions. This will reduce the risk associated with EDG maintenance and the synergistic effects on risk due to EDG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.

- Permit scheduling of EDG overhauls within the requested 14-day Completion Time extension period.

The proposed Completion Time of 14 days is adequate to perform normal preventive EDG inspections and maintenance requiring disassembly of the EDG and to perform post-maintenance and operability tests required to return the EDG to operable status.

Braidwood and Byron Stations intend to use the proposed 14-day Completion Time extension for performing a planned major overhaul at a frequency of no more than once per EDG per operating cycle. Beyond that, Braidwood and Byron Stations shall continue to minimize the time periods to complete any unplanned maintenance. Plant configuration changes for planned and unplanned maintenance of the EDGs as well as the maintenance of equipment having risk significance is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the consequences of a severe accident.

2 EVALUATION

The proposed changes have been evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increase in core damage frequency (CDF) and large early release frequency (LERF) is small and consistent with the NRC Safety Goal Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995.

The justification for the use of an EDG extended Completion Time is based upon a risk-informed and deterministic evaluation consisting of three main elements: 1) the availability of the "preferred" and "reserve" offsite power sources via the system auxiliary transformers (SATs) and unit cross-tie, 2) verification that the opposite unit EDGs and offsite power source are operable, and 3) implementation of the CRMP while an EDG is in an extended Completion Time. The CRMP is used for EDG as well as other work and helps ensure that there is no significant increase in the risk of a severe accident while any EDG maintenance is performed. These elements provide the bases for the proposed TS change by providing a high degree of assurance that power can be provided to the ESF buses during all DBAs (i.e., Dual Unit Loss of Offsite Power (DLOOP), Single Unit LOOP/ Loss of Coolant Accident (LOCA)), Station Black-out (SBO) and a fire during the EDG extended Completion Time.

2.1 Compliance with Applicable Regulations

The proposed changes meet applicable regulations and license conditions. Implementation of the proposed change will: 1) include the establishment of additional operational constraints, and 2) reflect practical considerations for test and maintenance, such as eliminating the restriction on performance of the 24-hour EDG endurance run during Modes 1 and 2 so that post-maintenance testing can be safely and effectively performed on-line. Other than the deviations from Regulatory Guide

1.93 guidance discussed in Section 2.2.1.2 (b) below, the proposed changes are consistent with current commitments.

2.1.1 Conformance to Improved Standard Technical Specifications

The proposed changes differ from Improved Standard Technical Specifications (ISTS) (i.e., NUREG 1431, "Standard Technical Specifications Westinghouse Plants, Rev. 1, April 1995) in that ISTS provide a Completion Time of 72 hours and the proposed change is for a Completion Time of 14 days. The 14-day Completion Time is needed to perform required maintenance and testing.

2.2 Traditional Engineering Considerations – EDG Completion Time Extension

The extension of the EDG Completion Time is addressed in this section. The evaluation of the proposed change to allow the 24-hour EDG endurance run to be performed in any Mode or Condition is addressed in Section 2.3. The NRC recently approved a similar request for the Perry Nuclear Plant Unit 1 when it issued Amendment 99 to Facility Operating License No. NPF-58 via letter dated February 24, 1999.

2.2.1 Defense - in - Depth

The impact of the proposed TS change was evaluated and determined to be consistent with the defense-in-depth philosophy. The defense-in-depth philosophy in reactor design and operation results in multiple means to accomplish safety functions and prevent release of radioactive material.

Byron and Braidwood Stations are designed and operated consistent with the defense-in-depth philosophy. The Stations have diverse power sources available (e.g., EDGs and opposite unit EDGs and SATs) to cope with a loss of the preferred AC source (i.e., offsite power). In addition, the opposite unit EDGs can be temporarily used to compensate for an onsite emergency power source that is not available without significantly increasing the likelihood of an extended SBO event. The overall availability of the AC power sources to the ESF buses will not be reduced significantly as a result of increased on-line preventive maintenance activities. It is therefore, acceptable, under certain controlled conditions, to extend the Completion Time and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

While the proposed change does increase the length of time an EDG can be out of service during unit operation, it will also increase the availability of the EDGs while the unit is shutdown. Even with one EDG out of service during operation, the system is designed with adequate defense-in-depth. The increased availability of the EDG while shutdown will increase the systems defense-in-depth during outages. Even with one EDG out of service there are multiple means to accomplish safety functions and prevent release of radioactive material. The Byron and Braidwood Station PRAs confirm the results of the deterministic analysis, i.e., the adequacy of defense-in-depth and that protection of the public health and safety are ensured.

System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. As demonstrated in Section 2.4 below there are no risk outliers. Implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. Station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense-in-depth whenever the EDGs are out of service. In addition, appropriate personnel are trained on the operation and maintenance of the EDGs and the bus cross-tie breaker. The use of the cross-tie breaker is governed by procedure.

No new potential common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised.

Independence of physical barriers to radionuclide release is not affected by these proposed changes.

Adequate defenses against human errors are maintained. These proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. Qualified personnel will continue to perform EDG maintenance and overhauls whether they are performed on-line or during shutdown. The maintenance activities are not affected by this change with the exception that the 24-hour EDG endurance run will be performed on-line. No other new actions are necessary because the overhaul will be performed on-line.

Section 3.1, "Conformance with NRC General Design Criteria," of the Byron and Braidwoods Station Updated Final Safety Analysis Reports (UFSARs) provides the basis for concluding that the stations fully satisfy and are in compliance with the NRC General Design Criteria (GDC) in Appendix A to 10 CFR Part 50. These proposed changes do not affect the basis for this conclusion and does not affect compliance with NRC GDC.

2.2.1.1 Availability of the Off-Site Power System

The safety related equipment required to mitigate the consequences of postulated accidents consists of two independent and redundant divisions of equipment. Each of these divisions can be powered using three independent sources of power. Loss of a single power source by voluntary entry into a TS Action for EDG maintenance does not reduce the amount of available equipment to a level below that necessary to mitigate DBAs and SBO. The remaining power sources are designed with adequate independence, capacity and flexibility to ensure that power will be provided to the necessary equipment during postulated accidents.

The ESF power systems at the Byron and Braidwood Stations are comprised of two electrically independent and physically isolated electrical divisions per unit (i.e.,Division 11 and 12 for Unit 1 and Division 21 and 22 for Unit 2). All ESF equipment required to shut down the reactor and remove decay heat for extended periods of time following a LOOP or a LOCA are supplied with AC power from the Class 1E power system. Loss of one of these divisions will not prevent safe shutdown of the units. Each division consists of a Class 1E 4.16-kV bus which feeds the various ESF loads and downstream buses. Each 4.16-kV bus has three independent sources of power.

- A normal preferred source from the offsite 345-kV system through the SATs directly to each bus. There are two SATs per unit, each one feeding a Class 1E 4.16-kV bus.
- A second reserve source from the 345-kV switchyard. This source is a delayed access circuit requiring manual operator action. Power is taken from the other unit's SATs via a cross-tie between the 4.16-kV ESF buses of the two units.
- An emergency onsite source consisting of one dedicated EDG per 4.16-kV ESF bus.

Simplified single line diagrams are included at the end of this attachment.

The 345-kV offsite power system provides two physically separate and electrically independent circuit paths between the transmission network and the onsite power system. One circuit is normally connected to the 4.16-kV ESF buses, and the other circuit is available as a delayed access circuit from the SATs of the opposite unit.

The 345 kV system is comprised of the various circuits from the transmission system, the switchyard, the circuits from the switchyard to the SATs and the SATs. Byron and Braidwood Stations have four and six separate circuits, respectively, entering the switchyard via three separate right-of-ways. These circuits connect to the switchyard. The switchyard is configured in a double ring bus configuration. The double ring bus configuration allows the stations to align any offsite power source to either unit. The transmission line structures are designed for heavy ice loading, high winds, and broken wire loading. Dampers are installed on all conductors and static wires to control high frequency vibration.

Two physically independent 345-kV transmission lines are available from the switchyard to the station. These two power circuits enter through two physically separate right-of-ways with independent transmission line structures. These lines connect to the opposite side of the switchyard and terminate at transformers located on the opposite sides of the containments. There are no other lines crossing these preferred power lines. No single event, such as a breaker failing open, a bus fault in the switchyard, or a failure on a transmission tower, will cause simultaneous loss of both offsite power sources. Switchyard power is available to both units as long as at least one 345-kV transmission line is available at the switchyard. 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 SATs step the 345-kV system voltage down to the station 4160-volt and 6900-volt power systems. Each set of SATs is sized to provide the required power of a unit under start-up, full load, safe shutdown and DBA load conditions. Each set of SATs is also 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.

The normal (i.e., preferred) source of offsite power is provided directly to each 4.16-kV bus via the corresponding SAT. The second (i.e., reserve) source of offsite power is available from the opposite unit's SAT via a cross-tie between the 4.16-kV buses on each unit (i.e., Division 11 to Division 21 and Division 12 to Division 22). This cross-tie is manually operated using established procedures.

For the previous two full calendar years (i.e., 1997 and 1998) there has been only one instance of unplanned SAT unavailability. In September of 1998, Braidwood Station Unit1 SATs (i.e., 142-1 and 142-2) were unavailable at different times for 9.3 hours. Over that two year period for the eight SATs at Byron and Braidwood Stations the unplanned SAT unavailability is 0.027%.

In summary, the offsite power system consists of independent transmission lines into the switchyard, a switchyard in a double ring bus configuration and two independent circuits into the plant through four SATs. A single loss of an incoming transmission line, a switchyard breaker, a transmission tower, a SAT or a circuit into the plant will not result in unavailability of offsite power.

2.2.1.2 Availability of the On-Site Power System

Loads important to plant safety are divided into redundant groups (i.e.,Division 11 (21) and 12 (22) for Unit 1 (Unit 2)). Each Division is supplied standby power from an individual EDG. Each EDG is completely independent of any auxiliary transformer in the performance of its required function. The EDGs are physically and electrically independent. With this arrangement, redundant components of all ESF systems are supplied from a separate ESF bus so that no single failure can jeopardize the proper functioning of redundant ESF loads. Due to the redundancy of the unit's ESF divisions and EDGs, the loss of any one of the EDGs will not prevent the safe shutdown of the unit. The total standby power system, including EDGs and electrical power distribution equipment, satisfies the single failure criterion.

The purpose of the EDGs is to provide an onsite standby power source upon the loss of normal and reserve offsite power sources. An EDG is automatically started by a safety injection signal or an under-voltage signal on the 4.16 kV ESF bus served by the EDG. Upon loss of voltage on a 4.16 kV ESF bus due to a LOOP with no safety injection signal present, under-voltage relays automatically start the EDGs. Sequential loading of the EDG is automatically performed.

A cross-tie breaker between each 4.16kV ESF bus and its associated 4.16kV non-safety-related bus may be manually closed, by operator action, in the event of the loss of both Unit Auxiliary Transformer and SAT, the normal feeds to the non-safety-related bus. The ESF bus can be used to power certain non-safety-related, but essential loads that are within the capability of the EDG. The operator may manually synchronize the reserve offsite power source to the ESF bus. Load limits on the cross-tie are controlled in both normal and Emergency Operating Procedures (EOPs).

In the event of a LOCA with sustained offsite power, ESF actuation signals will simultaneously start the necessary safety-related equipment. The EDGs will start but will not connect to the buses.

In the event of a LOCA coincident with a LOOP, under-voltage relays on each 4.16kV ESF bus will open the SAT feeder breaker, shed all loads on that bus except for the 4160-480 volt auxiliary transformers, and start the associated EDG. After the EDG has reached required frequency and voltage, the EDG feeder breaker will automatically close. The automatic loading of the ESF bus is accomplished by the load sequencing panels. The load sequencing panels are electrically and physically separated by division. Load sequencing will begin provided the EDG feeder breaker has closed and power is restored to the load sequencing circuit and cross-tie feeder breaker and SAT breaker are open.

The EDG feeder breaker will close to its associated load group automatically only if the other source feeder breakers to the load group are open. When the EDG feeder breaker is closed, no other source feeder breaker will close automatically. Electrical interlocks ensure that no means exist for connecting redundant load groups with each other.

The design basis for the EDGs is that loss of one EDG will not result in the loss of safety function. With two EDGs available per unit, the design is capable of performing its intended safety function with an assumed single failure of one EDG.

(a) SBO EDG Capacity

Byron and Braidwood Stations are able to withstand and recover from a SBO event of four hours in accordance with the guidelines of Revision 0 of RG 1.155, "Station Blackout." In the event of a SBO event, either one of the two EDGs 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 SBO event and has sufficient capacity and capability to operate equipment necessary to attain and maintain a safe shutdown condition for one affected unit.

Upon a LOOP and failure of both EDGs to start on one unit, either one of the other unit's EDGs is capable of providing power for safe shutdown of both units for a four-hour duration. A worst case EDG loading scenario was used in the SBO analysis. Equipment necessary for safe shutdown during the SBO coping duration is available and adequate no matter which EDG is used as the alternate AC source. Total EDG loading for an SBO event is within the 2000-hour rating of the EDG. Loading is controlled via the EOPs governing loss of all AC power. All equipment required to mitigate an SBO event is capable of being powered from a single remaining EDG. The capability for providing power to the blacked-out unit is possible with manual operation of cross-tie breakers from the main control room.

The assumptions used in the SBO analysis regarding the availability and reliability of the EDGs are unaffected by this proposed change. The results of the SBO analysis are also unaffected by this change.

The impact of a SBO event on plant risk is discussed in Attachment E.

(b) Onsite Power System Design Criteria

Compliance with NRC design criteria is described in detail in UFSAR Section 8.1, "INTRODUCTION," and in UFSAR Appendix A "APPLICATION OF NRC REGULATORY GUIDES." Safety-related systems and components that require electrical power to perform their safety-related function are defined as Class 1E loads. These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with RG 1.6, Revision 0, dated August 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems," as discussed in Appendix A of the UFSAR is not affected by this change. These proposed changes do not add any loads to the EDGs; therefore, the selection of the capacity of the EDGs for standby power systems and conformance to the applicable Sections of RG 1.9, Revision 3, dated July, 1993, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies," are not affected by this change.

Byron and Braidwood Stations conformance with RG 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," is described in detail in Appendix A to the UFSAR. The RG guidance is to disallow "normal" sharing of systems such that "a reduction in the number and capacity of the on-site power sources to levels below those required for the same number of units located at separate sites," would not result. The interconnection between each unit's EDGs via the cross-tie provided by the Byron and Braidwood Stations design does not result in a reduction in either the number or the capacity of the AC power sources. The number and capacity of the AC power sources is exactly the same as if the units were located at separate sites. The interconnection is limited by procedural and administrative controls. The use of the cross-tie breaker provides defense-in-depth and added assurance that the plant can be safely shutdown in the event of an accident.

Byron and Braidwood Stations conformance with RG 1.93, Revision 0, dated December 1974, titled "Availability of Electric Power Sources," is described in Appendix A to the UFSAR. An exception to Regulatory Guide 1.93 was taken to allow preventive maintenance activities to be performed on the SATs during periods other than cold shutdown and/or refueling.

Conformance with RG 1.93 is affected by these proposed changes. Aside from the exception discussed above, the stations currently conform to the RG and specifically the position that the 72-hour Completion Time will not be entered for preventative maintenance of the EDGs. If the proposed changes are approved, the stations will continue to conform to RG 1.93 with the exception that the allowed Completion Time for restoration of an EDG will be increased to 14 days and will be used for EDG preventative maintenance.

Commitments to other key design criteria applicable to onsite electrical systems that would be unaffected by these proposed changes include: Regulatory Guide 1.53, Revision 0, dated June 1973, titled, "Single Failure Criterion," Regulatory Guide 1.62, Revision 0, dated October, 1973, titled "Manual Initiation of Protective Actions," and Regulatory Guide 1.75, Revision 2, dated September, 1978, titled "Physical Independence of Electrical Systems."

2.2.2 Other Considerations

As discussed in the previous section, conformance with relevant regulatory guidance is not affected by this proposed change, with the exception of RG 1.93. The RGs cited in the previous section endorse industry standards. For example, RG 1.9 endorses Institute of Electrical and Electronic Engineers (IEEE) Standard 387-1984, "IEEE Standard for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Generating Stations."

Safety analysis acceptance criteria in the UFSAR continue to be met.

The proposed changes do not affect any assumptions or inputs to the safety analyses. Unavailability of a single EDG due to maintenance does not reduce the number of EDGs below the minimum required to mitigate all DBAs. In addition, the proposed changes have no impact on the availability of the two off-site sources of power. The effect on UFSAR acceptance criteria has been assessed assuming that one EDG is out of service and no additional failures on the maintenance unit occur. All safety functions continue to be available and acceptance criteria are met.

2.3 Traditional Engineering Considerations – 24-Hour EDG Endurance Run On-Line

The SR specifying the 24-hour EDG endurance run (i.e., SR 3.8.1.14) is proposed to be revised to allow the SR to be performed during Modes 1 and 2. This test could then be performed as a post-maintenance verification test subsequent to performing the EDG overhaul on-line. In addition, once the SR is revised, the 24-hour endurance run can also be performed on an operable diesel in Modes 1 and 2.

The justification for the proposed change to allow performance of the 24-hour run on-line is that the surveillance does not render any additional safety system or component inoperable. This SR is performed by paralleling the EDG being tested to offsite power similar to the requirements of SR 3.8.1.3, which is typically a four-hour EDG run performed during plant operation. Performing a 24-hour EDG endurance run, instead of a four-hour monthly load run, increases the amount of time the EDGs are paralleled with offsite power. The EDGs were designed for parallel testing and as such, design features, such as protective devices, were included. The change does not affect parallel testing design features, the consequences of postulated failures during parallel testing, and postulated interactions with offsite power during parallel testing. If problems are encountered during testing, the EDG will separate from the bus allowing the offsite circuit to continue to supply the bus. Failure to meet the SR when performed at power will result in an inoperable EDG, which in itself does not result in a challenge to plant safety systems.

Only one EDG per unit will be in parallel with the offsite source at a time in order to prevent any grid disturbances from potentially affecting more than one EDG. During the test, the remaining EDG will be available to respond normally to a start signal. The unit's remaining EDG is capable of supplying power to mitigate all DBAs. This test configuration is consistent with the configuration used during the monthly EDG tests.

The EDG system design includes emergency override of the test mode for both accident conditions (safety injection) and loss of offsite power (LOOP) to permit response to bona fide emergency signals and return control of the EDG to the automatic control system. Upon receipt of either a safety injection signal or a loss of off-site power signal, the governor is automatically shifted from droop to the isochronous mode. The diesel generator breaker controls trip the breaker upon receipt of a safety injection signal concurrent with the EDG operating in the test mode.

Further justification is provided in that the amount of time that the EDGs will be inoperable will be reduced by improved maintenance scheduling permitted by the more flexible SR. The flexibility allows performing the 24-hour EDG endurance run in other than shutdown conditions when heavy and complex maintenance activities occur resulting in unavailability of equipment. In addition, the capability to safely complete emergency shutdown procedures following a DBA coincident with a single failure is maintained throughout the performance of the surveillance.

No actions will be taken to affect the operability of the unit's remaining EDG and its support systems throughout the surveillance test, and no actions will be taken to affect the capability of the onsite Class 1E AC electrical distribution system and its support systems to complete plant shutdown and maintain safe shutdown conditions following a DBA. If the EDG fails the 24-hour endurance test, it will be inoperable and the appropriate TS Required Actions will be taken.

Based on the above, although performance of the 24-hour EDG endurance test during power operation deviates from the ISTS, in the case of Byron and Braidwood Stations, the performance of this test during power operation is consistent with the robust design features of the plant and is therefore acceptable. The conclusion is based on 1) the remaining EDGs are available to respond to an EDG start signal and 2) a single EDG per unit has the capacity to mitigate the consequences of a DBA.

2.4 Evaluation of Risk Impact

Risk-informed support for these proposed changes is based on a PRA performed to quantify the change in CDF and LERF produced by the increased Completion Time for the EDGs, implementation of a CRMP to control performance of other high risk tasks during the EDG outage and consideration of specific compensatory measures to minimize risk.

The risk impact of the proposed changes has been evaluated and found to be acceptable. Overall risk increases only incrementally within acceptable limits. The effect on risk of the proposed increase in Completion Time for restoration of an inoperable EDG has been evaluated using NRC's three-tier approach suggested in RG 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications," dated August, 1998:

Tier 1 - PRA Capability and Insights,
Tier 2 - Avoidance of Risk-Significant Plant Configurations, and
Tier 3 - Risk-Informed Configuration Risk Management.

2.4.1 Tier 1: PRA Capability and Insights

Risk-informed support for these proposed changes is based on PRA calculations performed to quantify the change in CDF and LERF resulting from the increased Completion Times for the EDGs.

The Byron and Braidwood Stations PRAs used for the risk determinations are recent upgrades to the "Modified Individual Plant Examination (IPE)," submitted to the NRC by letter dated March 27, 1997. These modified IPEs had been accepted by the NRC by letters dated December 3, 1997 for Byron Station and October 27, 1997 for Braidwood Station. The NRC letters noted that the modified IPE submittals met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)," dated November 23, 1988.

Attachment E provides a brief summary of the recently upgraded Byron and Braidwood Stations PRAs with additional information related to EDG modeling. These PRAs address internal events at full power. Other risk sources and operating modes are discussed below. In addition to incorporating recent advances in PRA technology across all elements of the PRA, a special effort was made to ensure that those aspects of the PRA that are potentially sensitive to changes in EDG maintenance unavailability are adequate to evaluate the risk impacts of the increased Completion Times for the EDGs. These elements include the proper characterization of initiating events involving LOOP, treatment of time-dependent offsite power recovery, the Reactor Coolant Pump (RCP) seal LOCA model, treatment of operator actions to implement bus cross-ties and other EOPs, and data analysis of key parameters such as EDG failure rates, maintenance unavailabilities, and common cause failure probabilities.

For the Level 2 analysis (i.e., the containment analysis), LERF was estimated using the methodology in NUREG/CR-6595, January 1999, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This approach to LERF evaluation, while somewhat simplified, supports a realistic quantification of systemic contributions to containment isolation failures and bypass sequences that are actually derived from the Level 1 event sequence model, and a conservative evaluation of severe accident challenges, which are less important for PWRs with large dry containments

The scope, level of detail, and quality of the Byron and Braidwood Stations PRAs are sufficient to support a technically defensible and realistic evaluation of the risk change from this proposed Completion Time extension.

Updating and maintenance of the Byron and Braidwood Stations PRAs is controlled under ComEd Nuclear Engineering Procedure (NEP)-17-04, "Nuclear Engineering PRA Model Update Procedure."

An independent assessment of the Byron and Braidwood Stations PRAs, using the Self-Assessment Process developed as part of the Westinghouse Owners Group (WOG) PRA Peer Review Certification Program, was conducted by a recognized industry expert. This independent review was performed from May through July of

1999 to evaluate the quality of the PRAs and completeness of the PRA documentation. Substantive comments and observations generated by this assessment, including those focused on the risk elements that are needed to evaluate the proposed Completion Time extension, were addressed.

Peer review certification of the Braidwood Station PRA using the WOG Peer Review Certification Guidelines was performed during the week of August 30, 1999. This Peer Review Certification was carried out by a team of independent PRA experts from U.S. nuclear utility PRA groups and PRA consultant organizations. This intensive peer review involved about two person-months of engineering effort by the review team and provided a comprehensive assessment of the strengths and limitations of each element of the PRA. All of the findings and observations from this assessment, that the review team indicated were important, and which involved risk elements that are needed to evaluate the proposed Completion Time extension, were dispositioned. This resulted in a number of enhancements to the PRA models prior to their use to support these proposed changes. On the basis of its evaluation the certification team determined that, with these enhancements incorporated, the quality of all elements of the PRA are of sufficient quality that "supports risk significant evaluations with deterministic input relative to the requested completion time extension." As a result of the considerable effort to incorporate the latest industry insights into the PRA upgrades, self-assessments, and certification peer reviews, ComEd is confident that the results of the risk evaluation are technically sound and consistent with the expectations for PRA quality set forth in RG 1.177 and 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."

Due to the commonalities in plant designs between Byron and Braidwood Stations, and the corresponding commonalities in the PRA methods and models, the Braidwood Station PRA Certification leads to confidence in the quality of the Byron Station PRA models. Most of the findings and observations that were made by the Braidwood Station PRA Certification Team were directly applicable to the Byron Station PRA as well. ComEd will schedule a Certification of the Byron Station PRA to be conducted in the year 2000. This Certification will provide an opportunity to evaluate any technical issues that are unique to Byron Station and at the same time provide an opportunity for the Byron Station PRA Certification team to examine how ComEd has dealt with the applicable issues from the Braidwood Station certification. The Certification process is not expected to affect the conclusions of this submittal.

To determine the effect of the proposed 14-day Completion Time for restoration of an inoperable EDG, the guidance suggested in RG 1.174 and 1.177 was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the EDG Completion Time from three days to 14 days.

ΔCDF_{AVE} = change in the annual average CDF due to any increased on-line maintenance unavailability of EDGs that could result from the increased Completion Time. This risk metric is used to compare against the criteria of RG 1.174 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, CDF_{BASE}.

$RAW_{BASE}\{EDGxY\}$ = risk achievement worth of EDG on Train Y at Unit x calculated using the Base PRA model for Unit x. This risk metric measures the factor increase in the baseline CDF associated with the failure or unavailability of a particular EDG component without regard to any compensating measures that may be taken to minimize the resulting risk impact.

$\Delta LERF_{AVE}$ = change in the annual average LERF due to any increased on-line maintenance unavailability of EDGs that could result from the increased Completion Time. RG 1.174 criteria were also applied to judge the significance of changes in this risk metric.

$ICCDP\{EDGxY\}$ = incremental conditional core damage probability with EDG Y on Unit x out-of-service for an interval of time equal to the proposed new Completion Time (i.e.,14 days). This risk metric is used as suggested in RG 1.177 to determine whether a proposed increase in Completion Time has an acceptable risk impact.

$ICLERP\{EDGxY\}$ = incremental conditional large early release probability with EDG Y on Unit x out-of-service for an interval of time equal to the proposed new Completion Time (i.e., 14 days). RG 1.177 criteria were also applied to judge the significance of changes in this risk metric.

The evaluation of the above risk metrics was performed as follows.

The change in the annual average CDF at each reactor Unit x due to the change in the EDG completion time, ΔCDF_{xAVE} ,was evaluated by computing:

$$\Delta CDF_{xAVE} = \left(\frac{T_{xA}}{T_{CYCLE}}\right)CDF_{xAOOS} + \left(\frac{T_{xB}}{T_{CYCLE}}\right)CDF_{xBOOS} + \left(1-\frac{T_{xA}+T_{xB}}{T_{CYCLE}}\right)CDF_{xBASE} - CDF_{xBASE}$$

where the following definitions were applied.

CDF_{xAOOS} = CDF evaluated from the PRA model for Unit x with the EDG train A out-of-service and compensating measures for EDG xA implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

CDF_{xBOOS} = CDF evaluated for the PRA model for Unit x with the EDG train B out-of-service and compensating measures for EDG xB implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

T_{xA} = Total time per fuel cycle (T_{CYCLE}) that EDG A on Unit x is out of service for the extended Completion Time

T_{xB} = Total time per fuel cycle (T_{CYCLE}) that EDG B on Unit x is out of service for the extended Completion Time

CDF_{xBASE} = baseline annual average CDF for Unit x with average unavailability of EDGs consistent with the current EDG Completion time. This is the CDF result of the current baseline PRAs for each Unit x, where x covers Braidwood and Byron Stations, Units 1 and 2. Note that there were separate PRA models developed for each of the four units at these two stations. More information on the baseline PRA models and how the EDGs were evaluated is provided in Attachment E.

A similar approach was used to evaluate the change in the average LERF for each Unit x due to the requested Completion Time, $\Delta LERF_{xAVE}$:

$$\Delta LERF_{xAVE} = \left(\frac{T_{xA}}{T_{CYCLE}}\right) LERF_{xAOOS} + \left(\frac{T_{xB}}{T_{CYCLE}}\right) LERF_{xBOOS} + \left(1 - \frac{T_{xA} + T_{xB}}{T_{CYCLE}}\right) LERF_{xBASE} - LERF_{xBASE}$$

where the following definitions were applied.

$LERF_{xAOOS}$ = LERF evaluated from the PRA model for Unit x with the EDG train A out of service and compensating measures for EDG xA implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$LERF_{xBOOS}$ = LERF evaluated for the PRA model for Unit x with the EDG train B out of service and compensating measures for EDG xB implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$LERF_{xBASE}$ = baseline annual average LERF for Unit x with average unavailability of EDGs consistent with the current EDG Completion time. This is the LERF result of the current baseline PRAs for each Unit x, where x covers Braidwood and Byron Stations, Units 1 and 2. Note that there were separate PRA models developed for each of the four units at these two stations. More information on the baseline PRA models and how the EDGs were evaluated is provided in Attachment E.

The evaluation was performed based on the assumption that the extended Completion Time would be applied to only one major overhaul per EDG per refueling cycle, hence T_{xAOOS} = T_{xBOOS} = 14 days. The cycle time is based on the current 18-month fuel cycle and an assumed total planned and unplanned outage duration of 30 days, which yields T_{CYCLE} = 518 days. Note that the above formula for ΔCDF_{xAVE} conservatively neglects the decrease in CDF contributions from accidents initiated during shutdown that will be associated with increased EDG availability of the EDGs during shutdown periods. It is also recognized that these estimates are obtained using a PRA model that does not include contributions from internal fires, seismic events and other external events. However, due to the common cause nature of these events and the fact that increased Completion Times only impact the risk contributions of independent component maintenance unavailabilities, inclusion of fires and external events would not impact the conclusions of this evaluation. While such contributions, if added would make small contributions to the base CDF, the change in CDF or LERF due to the increased Completion Time would be unaffected.

The risk achievement worth for each EDG was computed according to the standard definition for RAW (i.e., Electric Power Research Institute (EPRI) Technical Report (TR), "PSA Applications Guide," EPRI TR-105396, dated August 1995). The risk achievement worth for each EDG train is defined as the ratio of the CDF with the EDG train assumed to be failed with no compensating measures applied to the baseline CDF for that unit.

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) are computed using their definitions in RG 1.177. In terms of the above defined parameters, the definition of ICCDP is as follows:

$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE})T_{CT}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * (14 days) * (365 days / year)^{-1}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * 3.84x10^{-2}$$

Note that in the above formula 365 days/year is merely a conversion factor to get the Completion Time units consistent with the CDF frequency units. The ICCDP values are dimensionless probabilities to evaluate the incremental probability of a core damage event over a period of time equal to the extended completion time. This should not be confused with the evaluation of ΔCDF_{xAVE} in which the CDF is averaged over an 18-month refueling cycle.

Similarly, ICLERP is defined as follows.

$$ICLERP_{xA} = (LERF_{xAOOS} - LERF_{xBASE}) * 3.84x10^{-2}$$

The intermediate results of the risk evaluation are presented in Tables A2.4-1A and A2.4-1B for Braidwood Station and Byron Station, respectively. These tables show the results for each train dependent calculation of risk metrics. The base CDF values for each unit range from about 4.9E-05/yr. to about 5.0E-05/yr based on the average unavailability of the EDGs using plant specific data. The CDF values are predicated on resolution of an existing identified flooding vulnerability discussed below.

The RAW values computed for each EDG train provide an insight from the baseline PRA regarding the asymmetry in the risk importance in this system. Note that for each unit at Braidwood and Byron Stations the Train A EDG has a higher RAW value than the Train B EDG. This is due to a class of sequences involving failures of both trains of Auxiliary Feedwater. The Auxiliary Feedwater System at each unit consists of an electric motor-driven pump on Train A and a diesel-driven pump on Train B. Following a LOOP and failure or unavailability of the diesel driven auxiliary feedwater pump, the loss of a Train A EDG produces loss of the Auxiliary Feedwater function whereas loss of Train B EDG does not impact this function. This asymmetry elevates the risk importance of Train A EDGs relative to Train B EDGs at each unit at Braidwood and Byron Stations. Based on this insight, the change in risk due to the extended Completion Time which is calculated for the Train A EDGs will bound (i.e., will exceed) that for Train B EDGs.

Another important insight from the PRA results in Tables A2.4-1A and A2.4-1B is the fact that the risk impacts associated with removing an EDG from service for any train, with or without the effects of compensating measures are relatively small, even though there are only two EDGs for each unit. The effects of TS restrictions and other compensating measures are reflected in the CDF_{xYOOS} and $LERF_{xYOOS}$ values but only some of these are reflected in the RAW values. These risk impacts are minimized by the capability to cross tie electric power from the other unit, which is assumed to require the availability of both EDGs on the other unit in accordance with the EOPs. Furthermore, the values listed for CDF_{xYOOS} and $LERF_{xYOOS}$ in these tables are much less than the values that could be inferred from the corresponding RAW values. This is true because the values for CDF_{xYOOS} and $LERF_{xYOOS}$ are computed in consideration of the fact that the TS and other compensating measures described in this evaluation restrict the unavailability of other equipment when an EDG is removed from service; whereas only some of these restrictions are reflected in the computation of the RAW values.

Table A2.4-1A Intermediate Results of Risk Evaluation for Braidwood Station

Risk Metric*	Braidwood Station Unit 1		Braidwood Station Unit 2	
	EDG Train A	EDG Train B	EDG Train A	EDG Train B
CDF_{xBASE}	4.86E-05/yr.		4.86E-05/yr.	
RAW_{xY}	2.71	1.07	2.71	1.07
CDF_{xYOOS}	5.80E-05/yr.	4.81E-05/yr.	5.80E-05/yr.	4.81E-05/yr.
$LERF_{xBASE}$	4.96E-06/yr.		4.96E-06/yr.	
$LERF_{xYOOS}$	5.43E-06/yr.	4.92E-06/yr.	5.43E-06/yr.	4.93E-06/yr.

* x = unit, Y = EDG Train

Table A2.4-1B Intermediate Results of Risk Evaluation for Byron Station

Risk Metric*	Byron Station Unit 1		Byron Station Unit 2	
	EDG Train A	EDG Train B	EDG Train A	EDG Train B
CDF_{xBASE}	4.98E-05/yr.		4.89E-05/yr.	
RAW_{xY}	2.79	1.16	2.49	1.39
CDF_{xYOOS}	5.93E-05/yr.	4.86E-05/yr.	5.79E-05/yr.	4.73E-05/yr.
$LERF_{xBASE}$	5.55E-06/yr.		5.47E-06/yr.	
$LERF_{xYOOS}$	5.95E-06/yr.	5.47E-06/yr.	5.85E-06/yr.	5.37E-06/yr.

* x = unit, Y = EDG Train

The results of the risk evaluation are compared in Table A2.4-1C with risk significance criteria from RG 1.174 for changes in the annual average CDF and LERF and from RG 1.177 for ICCDP and ICLERP. The increase in the annual average CDF and LERF from the proposed extended Completion Time is on the order of or less than ½ % of the respective baseline value for each reactor unit. The ICCDP and ICLERP evaluation was based on Train A EDGs, which, as noted above, provide the limiting values for this risk metric. The values for the ICCDP and the ICLERP demonstrate that the proposed EDG Completion Time change has only a small quantitative impact on plant risk. Margins to the ICCDP and ICLERP criteria are plotted in Figure A2.4-1. These exhibits demonstrate that the risk significance criteria at each unit are met with significant margin. The fraction of time spent with an EDG out of service could be increased by nearly a factor of two in relation to that assumed in the evaluation in Table A2.4-1C before any of the units would exceed the risk significance criteria.

Table A2.4-1C Results of Risk Evaluation for Braidwood and Byron

Risk Metric	Risk Significance Criterion	Risk Metric Results (% of Risk Significance Criterion)			
		Braidwood		Byron	
		Unit 1	Unit 2	Unit 1	Unit 2
ΔCDF_{AVE}	< 1.0E-06/yr	2.4E-07/yr. (24%)	2.4E-07/yr. (24%)	2.2E-07/yr. (22%)	2.0E-07/yr. (20%)
$ICCDP$*	< 5.0E-07	3.6E-07 (72%)	3.6E-07 (72%)	3.6E-7 (73%)	3.5E-07 (69%)
$\Delta LERF_{AVE}$	< 1.0E-07/yr.	1.2E-08/yr. (12%)	1.2E-08/yr. (12%)	8.7E-09/yr. (9%)	7.6E-09/yr. (8%)
$ICLERP$*	< 5.0E-08	1.8E-08 (36%)	1.8E-08 (36%)	1.5E-08 (31%)	1.5E-08 (29%)

* Values listed are for Train A EDG which are the limiting values for these Risk Metrics; Removal from service of Train A EDG has greater risk impact than for Train B EDG due to the functional dependence of Train A Auxiliary Feedwater Pumps on AC electric power and use of diesel-driven pumps on Train B. This is why RAW values for Train A EDGs are always greater than corresponding Train B EDGs, as shown on Tables A2.4-1A and A2.4-1B.

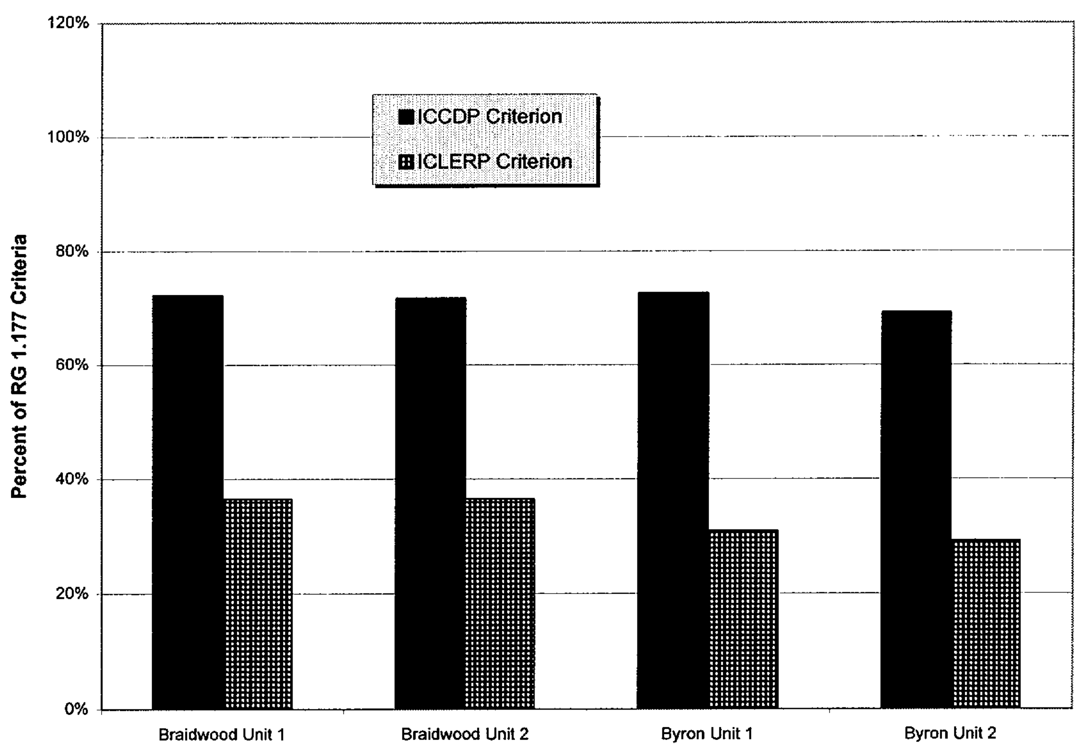


Figure A2.4-1 Margins Exhibited Against Regulatory Guide 1.177 Criteria for ICCDP and ICLERP

In determining the values in the above tables, the PRA quantification truncation limit was set to 1E-10/yr. This is more than five orders of magnitude below the total CDF and more than an order of magnitude below the value of the truncation limit recommended in Appendix B of EPRI TR-105396 "PSA Applications Guide," dated August 1995, "Checklist For Technical Consistency."

Flooding was evaluated in the internal flooding analysis and flooding initiators are included in the Byron and Braidwood Stations PRAs. The EDGs are located in areas which are not vulnerable to flooding. However, while evaluating the baseline risk profile a significant risk contributor associated with Auxiliary Building flooding was identified. Auxiliary Building flooding resulted in a loss of essential cooling water to the charging pump, leading to a loss of injection to the RCP seals. ComEd will eliminate this vulnerability by modifying the plant. One modification that is planned for both Byron and Braidwood Stations will provide alternate cooling to the charging pump lube oil cooler. The other modification planned for Braidwood Station only, will address a potential source of flooding via the essential cooling pond. The modifications will be implemented prior to implementing the changes proposed here once they are approved. Additional details regarding these modifications and the installation schedule will be provided by April 3, 2000. The above risk evaluations include the assumption that the design modifications will eliminate this risk contribution. At the completion of the modifications, and prior to implementation of these proposed changes once they are approved, an updated internal flooding evaluation will be performed to confirm that there is no impact on the conclusions of the current risk evaluation of the extended Completion Times.

A fire analysis was conducted as part of the Byron and Braidwood Stations Individual Plant Examination of External Events (IPEEE). The Byron Station IPEEE was submitted to the NRC on December 23, 1996 and the Braidwood Station IPEEE was submitted to the NRC on June 27, 1997. Requests for Additional Information (RAIs) were issued by the NRC on July 23 and July 9, 1998, for the Byron and Braidwood Stations respectively. Responses to most of the station-specific questions in the RAIs were provided on January 29, 1999. Plant-specific responses to the generic fire issues were provided on July 15, 1999, after the EPRI and Nuclear Electric Institute (NEI) final generic responses were issued.

The IPEEE fire analysis results were not combined with the internal events PRA results since the fire analysis was based on a conservative screening process using the EPRI Fire Induced Vulnerability Evaluation (FIVE) Programs in contrast with the realistic assessment of risk contributors in the internal events PRA. The majority of fire zones were screened due to lack of PRA targets or based on combustible material, fire detection, fire mitigation, and spatial separation. A few unscreened zones were postulated to produce a LOOP event as the result of a fire. For this to have an adverse impact during the planned EDG maintenance, the fire would also have to fail the offsite power circuits and the remaining ESF power division. The probability of this combination of failures is judged to be significantly lower than the truncation limit discussed above. This is consistent with the operating experience at both plants.

The IPEEE fire risk assessments at the Byron and Braidwood Stations resulted in a low fire CDF and did not identify any vulnerabilities. The proposed changes to the EDG Completion Time has a negligible effect, if any, on fire risk. Also, current administrative controls on activities with fire risk (i.e., welding, and cutting) are intended to increase the level of awareness during potentially risk significant activities and reduce fire risk.

The seismic analyses in the Byron and Braidwood Stations IPEEEs were based on the seismic margin assessment. No significant seismic concerns were identified and it was concluded that the plants possess significant seismic margin. The proposed changes to the EDG Completion Time has negligible effect on the seismic risk profile at Byron and Braidwood Stations.

Evaluation of high winds, external floods, and other external events in the Byron and Braidwood Stations IPEEE per NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," published in June 1991, indicated that the plant sites conform to NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," June 1987, criteria and revealed no potential vulnerabilities. The proposed changes to the EDG Completion Time extension has negligible effect on the risk profile at Byron and Braidwood Stations from other external events.

The risk evaluation reported herein shows that changes in risk due to the proposed changes to the Completion Time are determined by accident sequences and cutsets involving maintenance unavailability of individual EDG trains. Although common cause failures are important considerations in the determination of the baseline risk, the omission of fires, seismic events, and other external events from the Byron and Braidwood Stations PRA models that were used to perform the risk evaluation does not impact the evaluation of the risk metrics selected for the risk evaluation, namely, ICCDP, ICLERP, ΔCDF and ΔLERF. The change in risk due to the increased Completion Time that is determined by these risk metrics are fully dominated by accident sequences involving independent EDG maintenance unavailabilities.

Performing EDG overhauls on-line rather than during outages will increase EDG availability during outages. This will reduce shutdown risk by improving the availability of standby AC power sources for shutdown cooling equipment and other equipment needed to mitigate the events postulated to occur during shutdown. It will also increase the availability of the shutdown unit EDGs in support of the other unit through the cross-tie breakers if the need arose.

2.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

There is reasonable assurance that risk-significant plant equipment configurations will not occur when specific plant equipment is out of service consistent with the proposed TS changes.

2.4.2.1 TS require the SATs and cross-tie breaker to be operable. Offsite power operability is ensured by the performance of TS Section 3.8.1 Required Action B.2 to perform a surveillance test, SR 3.8.1.1, on the required qualified circuits. The opposite unit EDGs will be verified to be operable within one hour of entering the TS 3.8.1 Condition B and at least once per 24 hours thereafter, while the EDG is inoperable.

2.4.2.2 Increases in risk posed by potential combinations of equipment out of service will be managed under the CRMP. For example:

- An EDG extended Completion Time will not be entered for scheduled maintenance purposes if severe weather conditions are expected;
- While in the proposed extended EDG Completion Time, additional elective equipment maintenance or testing or equipment failure will be evaluated using the CRMP, activities that yield unacceptable results via the CRMP will be avoided; and
- The condition of the offsite power supply and switchyard including transmission lines and ring bus bus-tie breakers will be evaluated by performing switchyard walkdowns and conducting documentation reviews.

2.4.2.3 Compensatory actions have been identified that can mitigate any increase in risk. Byron and Braidwood Stations will have procedures in place for the following compensatory actions.

- No elective maintenance will be scheduled within the switchyard that would challenge the SAT connection or offsite power availability during the proposed extended EDG Completion Time.
- No elective work will be performed on the diesel-driven AFW Pump of the operating unit or the opposite unit, Essential Service Water (SX) Pumps or opposite Train ECCS equipment during the extended EDG Completion Time.
- Assure operating crews are briefed on the EDG work plan and key procedural actions regarding:
  - LOOP,
  - SBO,
  - Reactor Coolant System bleed and feed,
  - AC cross-tie,
  - refill of diesel-driven AFW pump fuel tank,
  - alignment of common CCW pump
- Assure availability of bleed and feed Systems, Structures and Components (SSCs) supported by the available EDG.

2.4.3 Tier 3: Risk-Informed Configuration Risk Management Program

Byron and Braidwood Stations have developed a Configuration Risk Management Program governed by Nuclear Station Procedure (NSP)-WC-3006, "On-Line Maintenance," that ensures that the risk impact of equipment out of service is appropriately evaluated prior to performing any maintenance activity. This program requires an integrated review (i.e., both probabilistic and deterministic) to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions.

Byron and Braidwood Stations currently have the capability to perform a configuration dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure/malfunction or emergent condition produces a plant configuration that has not been previously assessed.

For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed prior to scheduled work.

The assessment includes the following considerations.

- Maintenance activities that affect redundant and diverse SSCs that provide backup for the same function are minimized.

- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient are avoided.

- Work is not scheduled that is highly likely to exceed a TS or Technical Requirements Manual completion time requiring a plant shutdown. For activities that are expected to exceed 50% of a TS allowed outage time, compensatory measures and contingency plans are required to minimize SSC unavailability and maximize SSC reliability.

- For Maintenance Rule High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the Level 1 PRA model. The results of the risk assessment are classified by a color code based on the increased risk of the activity as follows:

Color	Meaning	Plant Impact and Required Action
Green	Non-Risk Significant	Small impact on Plant Risk No specific actions are required
Yellow	Non-Risk Significant with non-quantitative factors applied	Impact on Plant Risk Limit unavailability time or take compensatory actions to reduce plant risk.
Orange	Potentially Risk-Significant	Significant Impact on Plant Risk Requires Senior Management Review and Approval prior to entering this condition. Compensatory measures are required to reduce risk including contingency plans. All entries will be of short duration.
Red	Risk-Significant	Not entered voluntarily. If this condition occurs, immediate and significant actions shall be taken to alleviate the problem.

- Emergent work is reviewed by Shift Operations to ensure that the work does not invalidate the assumptions made during the work management process. If an offsite power source becomes unavailable or degraded, or the risk of losing offsite power significantly increases due to inclement weather (e.g., high wind, severe thunderstorm forecast, tornado watch/warning, or freezing rain), then systems required to mitigate the LOOP shall be made available as soon as possible in accordance with contingency plans.

- ComEd Procedure, NEP 17-04, "PRA Model Update Procedure," will be implemented at Byron and Braidwood Stations prior to implementing the proposed changes. This procedure defines the requirements for ensuring that the PRA model used to evaluate on-line maintenance activities is an accurate model of the current plant design and operational characteristics. Plant modifications and procedure changes will be monitored, assessed, and dispositioned. Evaluation of changes in plant configuration or PRA model features will be dispositioned by implementing PRA model changes or by the qualitative assessment of the impact of the changes on the PRA assessment tool. Changes that have potential risk impact are recorded in an Update Requirements Evaluations (URE) log for consideration in the next periodic PRA model update.

2.4.4 Integrated Risk-Informed Assessment

The proposed changes to TS Section 3.8.1 "AC Sources – Operating," extending the allowable Completion Times for the Required Actions associated with restoration of an inoperable EDG and SR 3.8.1.14 corresponding to the 24-hour EDG endurance run have been evaluated with a risk-informed approach. This approach demonstrates that the principles of risk-informed regulation are met for these proposed changes.

- Applicable regulatory requirements will continue to be met,
- Adequate defense-in-depth will be maintained,
- Sufficient safety margins will be maintained, and
- Any increases in CDF and LERF are small and consistent with the NRC Safety Goal Policy Statement.

This conclusion can be summarized by reviewing the capability of the plant to respond to events while an EDG is unavailable. The EDGs are provided to support plant response to events involving LOOP. Based on the plant specific PRA developed for Byron and Braidwood Stations, the most risk-significant scenarios in which EDGs are required involve EDG support of two important plant safety functions: AC Power Availability and Core Cooling. Table A2.4-1D provides a summary of the defense-in-depth of these safety functions for one unit, assuming offsite power is lost.

In the context of this evaluation, AC power availability involves the provision of AC power in the event normal offsite power supplies are lost for event mitigation and monitoring. For Byron and Braidwood Stations, this involves providing emergency AC power to the two major 4kV ESF buses 141 (or 241 for Unit 2) and 142 (or 242 for Unit 2). As described in detail in section 2.2, the plant design provides a number of diverse and redundant capabilities for providing AC power to these buses.

Assurance of adequate core cooling in a Westinghouse design Pressurized Water Reactor (PWR) involves three primary safety functions. The first function is the provision of adequate decay heat removal via the steam generators. In the event of a LOOP, this can be accomplished with either AFW pump.

The second function involves the assurance of the integrity of the Reactor Coolant System (RCS) pressure boundary. Since thermal hydraulic analyses demonstrate that LOOP events do not in themselves present a threat to RCS integrity (i.e., no challenge to the pressurizer Power Operated Relief Valves), the primary challenge to RCS integrity comes from assuring that the integrity of the RCP seals can be assured. This can be accomplished via either RCP seal injection using the Chemical Volume Control System or thermal barrier cooling using the CCW System.

The third component involves providing alternate core cooling via bleed and feed cooling, in the event either of the first two functions are challenged. Plant-specific thermal hydraulic analyses have demonstrated that plant EOPs support successful bleed and feed with the following minimum requirements: either one charging pump in safety injection mode with one PORV opened or one safety injection pump with both PORVs opened.

From Table A2.4-1D, it can be seen that in all cases, including those with an EDG out of service under the control of the Completion Time, the plant has at least two means of assuring that each safety function can be met. This result is consistent with the traditional engineering arguments provided in Sections 2.2 and 2.3 and the PRA insights summarized in Section 2.4.

Table A2.4-1D DEFENSE-IN-DEPTH SUMMARY FOR BYRON AND BRAIDWOOD STATIONS (BASED ON UNIT 1)

Configuration	AC POWER[1]		CORE COOLING[2]		
	Supplies to Bus 141	Supplies to Bus 142	Secondary Heat Removal	RCP Seal Cooling	Feed & Bleed Capability
NORMAL	• DG-1A • Cross-tie Offsite Power via Bus 241 • Cross-tie to DG-2A via Bus 241[3]	• DG-1B • Cross-tie Offsite Power via Bus 242 • Cross-tie to DG-2B via Bus 242[3]	• Motor-Driven AFW Pump 1A • Diesel-Driven AFW Pump 1B	• Thermal Barrier Cooling: - CCW A - CCW B - CCW "0" • Seal Injection -Charging Train A -Charging Train B	• Bleed Capability: - PORV 455A, or - PORV 456 • Coolant Injection: -Charging Train A -Charging Train B -SI Train A -SI Train B
DG-1A OOS	• Cross-tie Offsite Power via Bus 241 • Cross-tie to DG-2A via Bus 241[3]	• DG-1B • Cross-tie Offsite Power via Bus 242 • Cross-tie to DG-2B via Bus 242[3]	• Diesel-Driven AFW Pump 1B	• Thermal Barrier Cooling: - CCW B – CCW "0" • Seal Injection -Charging Train B	• Bleed Capability: - PORV 456 • Coolant Injection: -Charging Train B
DG-1B OOS	• DG-1A • Cross-tie Offsite Power via Bus 241 • Cross-tie to DG-2A via Bus 241[3]	• Cross-tie Offsite Power via Bus 242 • Cross-tie to DG-2B via Bus 242[3]	• Motor-Driven AFW Pump 1A • Diesel-Driven AFW Pump 1B[4]	• Thermal Barrier Cooling: - CCW A – CCW "0" • Seal Injection -Charging Train A	• Bleed Capability: - PORV 455A • Coolant Injection: -Charging Train A

NOTES:
1. Assuming Loss of Normal Offsite Power Supply
2. Without Crediting Any AC Power Cross-tie to Unit 2. With Successful AC Power Cross-tie the capability is NORMAL.
3. Requires BOTH Unit 2 EDGs to Be Available and Capable of Stable Operation
4. Diesel-driven AFW Pump 1B is AC Electric Power Independent

3. IMPLEMENTATION AND MONITORING PROGRAM

To ensure the proposed extension of the EDG Completion Time does not degrade operational safety over time, as part of the Maintenance Rule (MR) (i.e.,10 CFR 50.65), should equipment not meet its performance criteria, an evaluation is required. The evaluation will include prior related TS changes, including this one, in its scope. Appropriate corrective action will be taken, including a change to the TS if necessary, as required by the MR.

3.1 Maintenance Rule Program

The reliability and availability of the affected EDGs are monitored under the MR Program. If the pre-established reliability or availability performance criteria are exceeded for the EDGs, they are considered for 10 CFR 50.65 (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. The actual out of service time for the EDGs will be minimized to ensure the reliability and availability performance criteria for these ESF buses are not exceeded. The station on-line maintenance procedure will require that the work hours for on-line maintenance for equipment having a 14-day TS with a Shutdown required will be 24 hours a day, 7 days a week with off-hours callout for emergent issues.

The EDG availability used in the PRA analysis to calculate CDF values is conservative compared to the EDG system MR goals, actual past performance of the EDGs at the plants and expected availability following implementation of the proposed increased EDG Completion Time.

The MR program unavailability performance criterion for the EDGs is based on a combination of maintenance unavailability used in current PRA analyses and anticipated on-line maintenance requirements. The MR availability goal is no more than 18 outage days per two years per EDG. This corresponds to approximately an unavailability of 2.46%. Average unavailability in hours during 1997 and 1998 is 66.3 (i.e., 0.8%) and 90.9 (i.e., 1.0%) hours per EDG respectively for Byron Station, Units 1 and 2, and 18.9 (i.e., 0.2%) and 23.1 (i.e., 0.3%) hours per EDG respectively for Braidwood Station, Units 1 and 2. The unavailability expected once the 18-month, five-year and 20-year EDG overhauls are performed on-line will be 1.37% (i.e., 7.5 days per 18 months), 1.74% (9.5 days per 18 months) and 2.2% (12.5 days per 18 months) respectively based on the scope currently included in the overhauls. The unavailability assumed in the PRA considering the extended EDG Completion Time is 2.55E-02 (i.e., 14 days per 18 months) or 2.6% unavailability. The unavailability assumed in the PRA calculations for estimating the change in the average CDF and LERF due to the extended EDG Completion Time case is above the MR goal. Actual unavailability under the extended Completion Time is expected to be much less than that assumed in the PRA.

In accordance with current MR performance criteria, SAT availability is currently being tracked as an "offsite power source" such that the total outage time for all offsite power sources is less than 14 days per two years per SAT and less than six days per two years for both SATs. The availability of the SATs is unaffected by the proposed change.

The EDGs are all currently in the 10 CFR 50.65 a(2) MR category (i.e., the EDGs are meeting established performance goals). Performance of the EDG on-line maintenance is not anticipated to result in exceeding the current established MR criteria for EDGs. This is based on the expected number of unavailability days per cycle per EDG due to periodic overhauls being moved from refueling outage to power operation.

The actual EDG reliability and availability is monitored and periodically evaluated to assess the effect of the proposed extended EDG Completion Time upon plant performance in relationship to the MR goals and SBO target values.

To ensure the TS Completion Time does not degrade operational safety over time, the MR Program is used, as discussed above, to identify and correct adverse trends.

Compliance with the MR not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out of service for testing or maintenance per 10CFR50.65 (a)(3).

Plant modifications and procedure changes will be monitored, assessed and dispositioned. Evaluation of changes in plant configuration or PRA model features will be dispositioned by implementing PRA model changes or by qualitatively assessing the impact of the changes on the CRMP assessment tool.

Procedures include a description of the process when the plant configuration of concern is outside the scope of the CRMP assessment tool and procedures will exist for the control and application of CRMP assessment tools.

3.1.1 TS Section 5.5.15, "Safety Function Determination Program (SFDP)"

The SFDP was added to the TS as a result of the conversion to the Improved Standard TS (ISTS). Training on the SFDP was provided to all licensed operations personnel prior to implementation of ISTS. This program requires provisions for cross-division checks to ensure a loss of the capability to perform a safety function assumed in the accident analysis does not go undetected. TS LCO 3.0.6 establishes requirements regarding supported systems when support systems are found inoperable. Upon entry into TS LCO 3.0.6 an evaluation is required to determine whether there has been a loss of safety function. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of TS LCO 3.0.6

3.1.2 Change Control

The CRMP will be referenced and maintained as an administrative program in the Byron and Braidwood Stations Technical Requirements Manuals (TRMs). RG 1.177 recommends that the CRMP be described in the TS Administrative Controls Section. ComEd will describe the CRMP in the TRM. The TRM was developed in conjunction with conversion to ISTS and contains various plant conditions, actions, and testing similar to the TS, which are required to support appropriate operation in accordance with commitments. Changes to the TRM are subject to the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments."

The goals of a CRMP are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during the proposed extended EDG Completion Time. Incorporating a CRMP into the TS is not necessary because the following risk management processes also satisfy the goals of a CRMP:

- compliance with 10 CFR 50.65, "Requirements For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants,"
- compliance with existing plant procedure NSP-WC-3006, "On-line Maintenance," and,
- compliance with TS Section 5.5.15, "Safety Function Determination Program (SFDP)."

3.1.3 Industry and Plant Operating Experience

Industry and plant operating experience were reviewed to assess the proposed change. A number of plants have been performing EDG maintenance on-line for several years and no events or adverse consequences have been experienced to date.

4. IMPACT ON PREVIOUS SUBMITTALS

This request has no impact on previous submittals.

5. SCHEDULE REQUIREMENTS

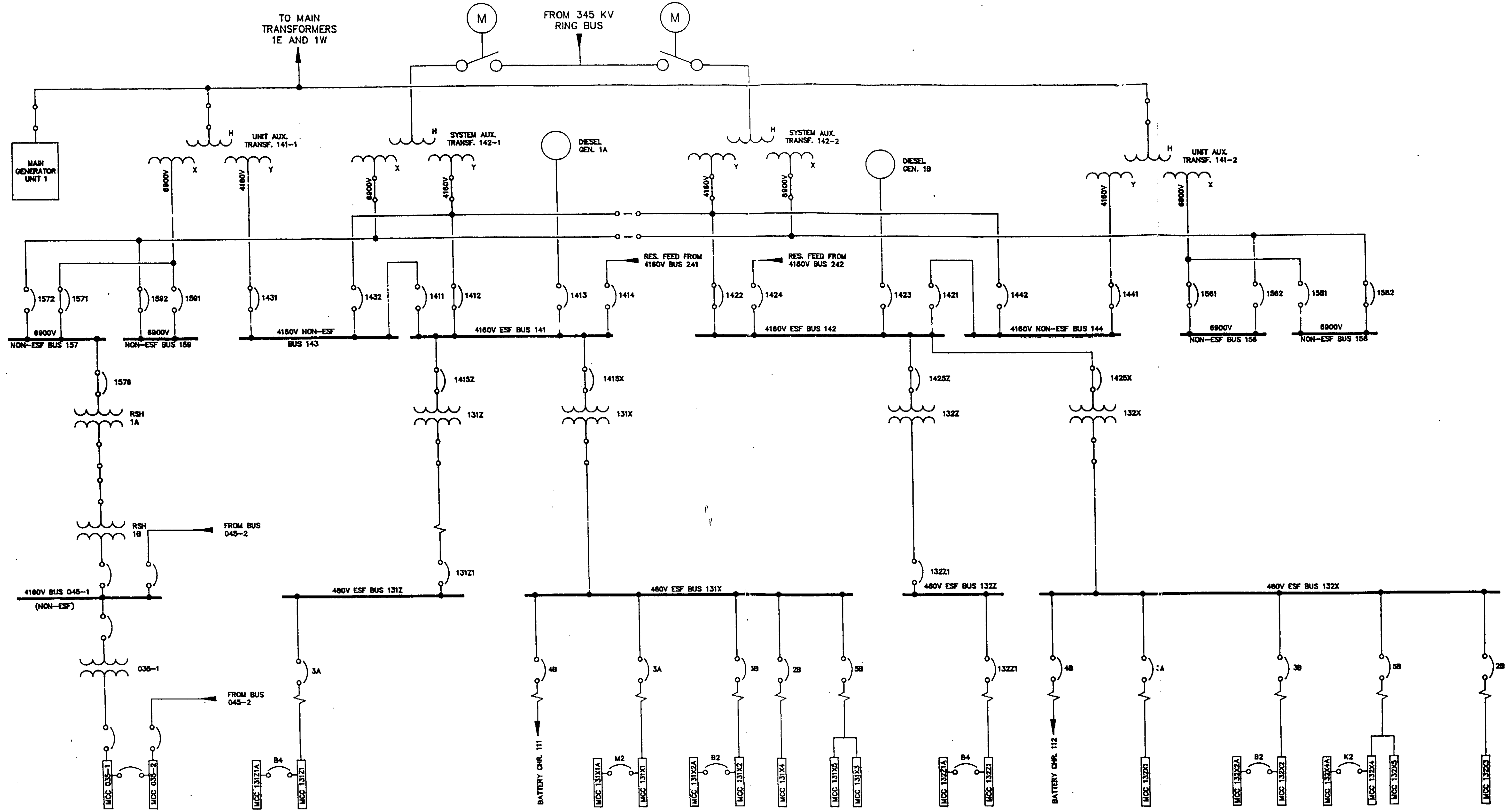
ComEd requests approval of these proposed TS changes by August 1, 2000 to support procedure changes and work planning necessary to accomplish EDG maintenance activities prior to the Byron Station, Unit 1 and Braidwood Station, Unit 2 Refueling Outages scheduled to begin in the Fall of 2000.

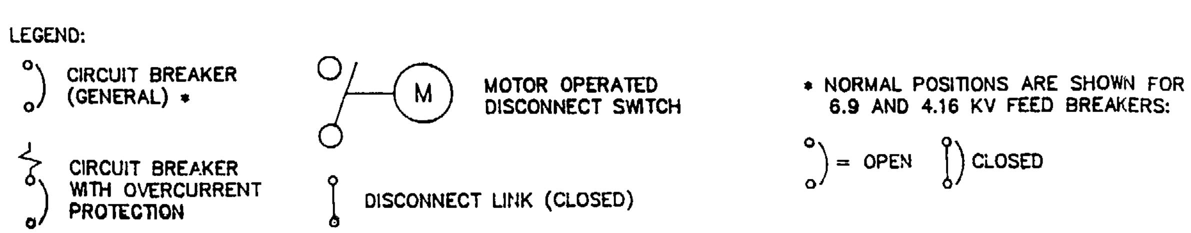
6. CONCLUSION

The proposed 14-day EDG Completion Time is based upon both a deterministic evaluation and a risk-informed assessment. The risk assessment concluded that the increase in plant risk is small and consistent with the USNRC "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Vol.51, p.30028 (51 FR 30028), August 4, 1986 as interpreted by NRC Regulatory Guides 1.174 and 1.177. The deterministic evaluation consisted of three main elements: 1) the availability of offsite power via the SAT and unit cross-tie, 2) verification that the opposite unit EDGs and offsite power source are operable, and 3) implementation of a CRMP while the EDG is in an extended Completion Time. The evaluation concluded that the proposed changes are consistent with the defense-in-depth philosophy and that sufficient safety margins are maintained. Together these analyses provide high assurance of the capability to provide power to the ESF buses during the proposed 14-day EDG Completion Time.

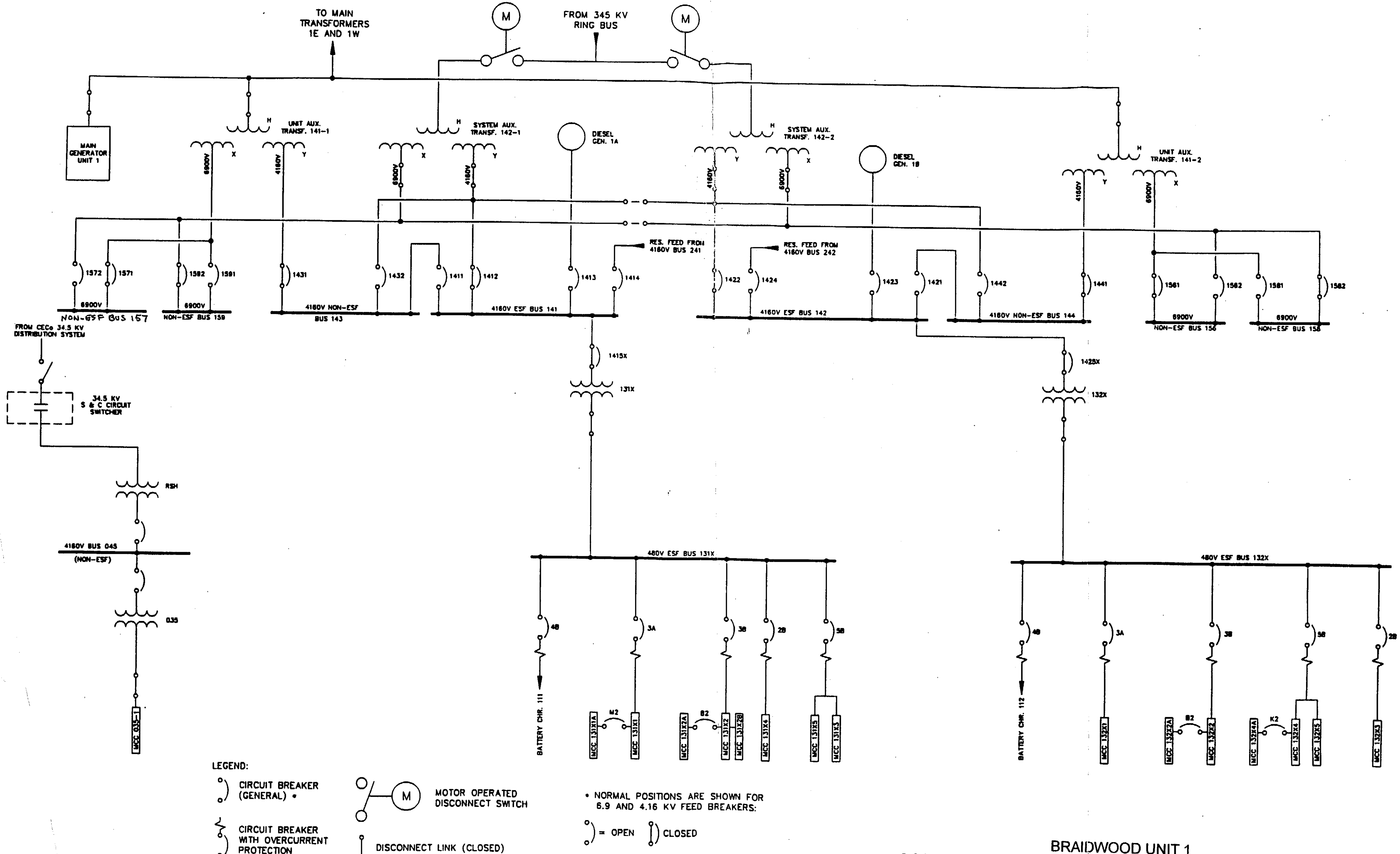
The use of the SAT and opposite unit SATs and EDGs via the unit cross-tie, and the CRMP have been shown to provide more than adequate compensation for the potential small increase in plant risk of the extended EDG Completion Time. Maintenance during power operation will reduce shutdown risk by increasing the availability of the emergency power during refueling outages. The proposed change in EDG Completion Times in conjunction with the availability of the SATs from both units and use of the CRMP during the proposed extended EDG Completion Time, will provide adequate assurance of the capability to provide power to the ESF buses. The amount of equipment required to mitigate DBAs will not be reduced below the required level by performance of the EDG on-line maintenance.

The proposed changes meet the applicable regulatory requirements. The proposed deviation from Regulatory Guide 1.93 is considered acceptable. The proposed change results in a small increase in CDF and LERF, but the small increase in plant risk is consistent with the intent of the NRC Safety Goal Policy Statement. The impact of the proposed change will be monitored using performance measures to ensure actual reliability and availability is consistent with the values used in the PRA.





BYRON UNIT 1
6.9 KV, 4.16 KV AND 480 V ELECTRICAL DISTRIBUTION SYSTEM (TYPICAL)



BRAIDWOOD UNIT 1
6.9 KV, 4.16 KV AND 480 V ELECTRICAL DISTRIBUTION SYSTEM (TYPICAL)

ATTACHMENT B-1

MARKED-UP PAGES FOR PROPOSED CHANGES

BRAIDWOOD STATION

(i) REVISED TS PAGES

3.8.1 - 1
3.8.1 - 2
3.8.1 - 3
3.8.1 - 4
3.8.1 - 9

(ii) REVISED BASES PAGES

B 3.8.1-7 through B 3.8.1-14

B 3.8.1-16

B 3.8.1-18

B 3.8.1-20

B 3.8.1-26

B 3.8.1-28

B 3.8.1-31

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

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
	AND		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours AND ~~6~~ 17 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Verify both opposite-unit DGs OPERABLE	1 hour AND Once per 24 hours thereafter
	AND B.~~1~~2	Perform SR 3.8.1.1 for the required qualified circuits.	1 hour AND Once per 8 hours thereafter
	AND B.~~2~~3	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND B.~~3~~4.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR B.~~3~~4.2	Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND B.~~4~~5	Restore DG to OPERABLE status.	14 days ~~72 hours~~ AND ~~6~~ 17 days from discovery of failure to meet LCO
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1	Restore DG to OPERABLE status	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~C~~ D. One or more buses with two required qualified circuits inoperable.	~~C~~ D.1 Restore one required qualified circuit per bus to OPERABLE status.	24 hours
~~D~~ E. One DG inoperable and one or more buses with one required qualified circuit inoperable. <u>OR</u> One DG inoperable and one bus with two required qualified circuits inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition ~~D~~ E is entered with no AC power source to a division. ---------------------------------- ~~D~~ E.1 Restore required qualified circuit(s) to OPERABLE status. <u>OR</u> ~~D~~ E.2 Restore DG to OPERABLE status.	 12 hours 12 hours
~~E~~ F. Two DGs inoperable.	~~E~~ F.1 Restore one DG to OPERABLE status.	2 hours
~~F~~ G. Required Action and associated Completion Time of Condition A, ~~B~~, C, D, E, or ~~E~~ F not met. <u>OR</u> Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.5 not met.	~~F~~ G.1 Be in MODE 3. <u>AND</u> ~~F~~ G.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~G~~. H Two DGs inoperable, and one or more buses with one or more required qualified circuits inoperable. OR One DG inoperable, one bus with two required qualified circuits inoperable, and the second bus with one or more required qualified circuits inoperable.	~~G~~.1 H Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required qualified circuit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds achieves voltage ≥ 3950 V and ≤ 4580 V; b. In ≤ 10 seconds achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	18 months
SR 3.8.1.13	Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except: a. Engine overspeed; and b. Generator differential current.	18 months
SR 3.8.1.14	-----NOTE~~S~~----- ~~1.~~ Momentary transients outside the load range do not invalidate this test. ~~2. This Surveillance shall not be performed in MODE 1 or 2.~~ ---------- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 5775 kW and ≤ 6050 kW; and b. For the remaining hours of the test loaded ≥ 4950 kW and ≤ 5500 kW.	 18 months

(continued)

BASES

ACTIONS (continued)

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days ~~72 hours~~. This could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the required qualified circuit(s). At this time, a DG could again become inoperable, the circuit(s) restored OPERABLE, and an additional 14 days ~~72 hours~~ (for a total of ~~9~~ 31 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1 (see attached) →

B.~~1~~ 2

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the required qualified circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a required qualified circuit fails to pass SR 3.8.1.1, it is inoperable, and additional Conditions and Required Actions apply.

B.1

The 14 day Completion Time for Required Action B.5 is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7). It is required to verify both opposite-unit DGs OPERABLE within 1 hour and to continue this action once per 24 hours thereafter until restoration of the required DG is accomplished. This verification provides assurance that opposite-unit DGs are capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

BASES

ACTIONS (continued)

B.~~2~~ 3

Required Action B.~~2~~ 3 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features (i.e., systems, subsystems, trains, components, and devices) are designed with redundant safety related trains. This includes the diesel driven auxiliary feedwater pump. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.~~2~~ 3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required redundant feature(s) results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

BASES

ACTIONS (continued)

In this Condition, the remaining OPERABLE DG and qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

<u>B.~~3~~4.1 and B.~~3~~4.2</u>

Required Action B.~~3~~4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition ~~E~~ F of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.~~3~~4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.~~3~~4.1 or B.~~3~~4.2, the Problem Identification and Investigation Procedure will continue to evaluate the common cause possibility and determine the need for any additional DG testing. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. ~~7~~ 8), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

BASES

ACTIONS (continued)

B.~~4~~ 5

According to ~~Regulatory Guide 1.93 (Ref. 6)~~ Reference 7, operation may continue in Condition B for a period that should not exceed ~~72 hours.~~ 14 days.

Insert 1 →

In Condition B, the remaining OPERABLE DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The ~~72 hour~~ 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.~~4~~ 5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a required qualified circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the DG. At this time, a required qualified circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9~~ 20 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour~~ 14 day and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.~~2~~ 3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1

(see Insert 2)

Insert 1

This Completion Time is based upon a risk-informed assessment that concluded that the associated risk is acceptable based upon the availability of the offsite power sources and the onsite standby power sources (i.e., the DGs), and the implementation of a Configuration Risk Management Program.

Insert 2

C.1

The 72 hour Completion Time is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7).

In Condition C, with an opposite-unit DG inoperable, the remaining OPERABLE unit-specific DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC Sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

D ~~C~~.1

With one or more buses with both of its required qualified circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the required qualified circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available required qualified circuits two less than required by the LCO, operation may continue for 24 hours. If two required qualified circuits are restored within 24 hours, unrestricted operation may continue. If only one required qualified circuit is restored within 24 hours, power operation continues in accordance with Condition A.

E ~~D~~.1 and E ~~D~~.2

In Condition E ~~D~~, with one DG inoperable and one or more buses with one qualified circuit inoperable or with one DG and one bus with both qualified circuits inoperable, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition ~~C~~ D. This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time to restore the DG or the required qualified circuit(s) takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition ~~D~~ E are modified by a Note to indicate that when Condition ~~D~~ E is entered with no AC source to any division (one or more divisions de-energized), the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition ~~D~~ E to provide requirements for the loss of one DG and one required qualified circuit on one or more buses, without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition ~~D~~ E for a period that should not exceed 12 hours.

F ~~E~~.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

BASES

ACTIONS (continued)

~~F~~G.1 and ~~F~~G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

~~G~~H.1

Condition ~~G~~ H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies may be lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown. Examples of inoperabilities that require entry into Condition ~~G~~ H are: 1) both DGs inoperable and both qualified circuits inoperable on one bus, and 2) one DG inoperable and both qualified circuits inoperable on one bus and one qualified circuit inoperable on the second bus.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. ~~8~~ 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. ~~10~~ 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

<u>SR 3.8.1.1</u>

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to reduce stress and wear on diesel engines, a modified start is used in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of starts in accordance with SR 3.8.1.2.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from normal standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see SR Note) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is also addressed in SR 3.8.1.2 Note.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. ~~7~~). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.
8

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. ~~10~~ 11). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The single largest post-accident load associated with each DG is the Essential Service Water (SX) pump (1290 brake horsepower, 1034 kW at full load conditions). This Surveillance is accomplished by simultaneously tripping loads supplied by the DG which have a minimum combined load equivalent to the single largest post-accident load. This method is employed due to the difficulty of attaining SX full load conditions during normal plant operations.

As required by IEEE-308 (Ref. ~~9~~ 10), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint (64.5 Hz), or 15% above synchronous speed (69 Hz), whichever is lower.

The voltage and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a ~~two Notes~~. Note ~~2~~ which states that momentary transients (e.g., due to changing bus loads) do not invalidate this test. ~~The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.~~

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Alternatively, the DG can be operated until operating temperatures have stabilized. Note 2 states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. ~~9~~ 10), paragraph 6.2.6(2).

The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. UFSAR, Chapter 8.

3. Regulatory Guide 1.9, Rev. 3, July 1993.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 15.

6. Regulatory Guide 1.93, Rev. 0, December 1974.

8. ~~7.~~ Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

9. ~~8.~~ 10 CFR 50, Appendix A, GDC 18.

10. ~~9.~~ IEEE Standard 308-1978.

11. ~~10.~~ Regulatory Guide 1.137, Rev. 1, October 1979.

7. R.M. Krich to NRC Document Control Desk Letter, "Request for Amendment to Technical Specifications Extension of Allowable Completion Times and Surveillance Requirement Change for Emergency Diesel Generators," January 20, 2000.

ATTACHMENT B-2

MARKED-UP PAGES FOR PROPOSED CHANGES

BYRON STATION

(iii) REVISED PAGES

3.8.1 - 1
3.8.1 - 2
3.8.1 - 3
3.8.1 - 4
3.8.1 - 9

(iv) REVISED BASES PAGES

B 3.8.1-7 through B 3.8.1-14

B 3.8.1-16

B 3.8.1-18

B 3.8.1-20

B 3.8.1-26

B 3.8.1-28

B 3.8.1-31

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

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
	AND		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours AND ~~6~~ 17 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required DG inoperable.	B.1 Verify both opposite-unit DGs OPERABLE	1 hour AND Once per 24 hours thereafter
	AND B.~~1~~2 Perform SR 3.8.1.1 for the required qualified circuits.	1 hour AND Once per 8 hours thereafter
	AND B.~~2~~3 Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND B.~~3~~4.1 Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR B.~~3~~4.2 Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND B.~~4~~5 Restore DG to OPERABLE status.	14 days ~~72 hours~~ AND ~~6~~17 days from discovery of failure to meet LCO
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1 Restore DG to OPERABLE status.	72 hours.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~C~~ D. One or more buses with two required qualified circuits inoperable.	~~C~~ D.1 Restore one required qualified circuit per bus to OPERABLE status.	24 hours
~~D~~ E. One DG inoperable and one or more buses with one required qualified circuit inoperable. <u>OR</u> One DG inoperable and one bus with two required qualified circuits inoperable.	——————NOTE—————— Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition ~~D~~ E is entered with no AC power source to a division. ———————————— ~~D~~ E.1 Restore required qualified circuit(s) to OPERABLE status. <u>OR</u> ~~D~~ E.2 Restore DG to OPERABLE status.	 12 hours 12 hours
~~E~~ F. Two DGs inoperable.	~~E~~ F.1 Restore one DG to OPERABLE status.	2 hours
~~F~~ G. Required Action and associated Completion Time of Condition A, ~~B~~, C, D, E, or ~~E~~ F not met. <u>OR</u> Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.5 not met.	~~F~~ G.1 Be in MODE 3. <u>AND</u> ~~F~~ G.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
~~G.~~ H. Two DGs inoperable. and one or more buses with one or more required qualified circuits inoperable. OR One DG inoperable. one bus with two required qualified circuits inoperable. and the second bus with one or more required qualified circuits inoperable.	~~G.~~1 H	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required qualified circuit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.12 Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds achieves voltage ≥ 3950 V and ≤ 4580 V; b. In ≤ 10 seconds achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	18 months
SR 3.8.1.13 Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except: a. Engine overspeed; and b. Generator differential current.	18 months
SR 3.8.1.14 -----NOTE~~S~~----- ~~1.~~ Momentary transients outside the load range do not invalidate this test. ~~2. This Surveillance shall not be performed in MODE 1 or 2.~~ ---------- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 5775 kW and ≤ 6050 kW; and b. For the remaining hours of the test loaded ≥ 4950 kW and ≤ 5500 kW.	18 months

(continued)

B.1

The 14 day Completion Time for Required Action B.5 is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7). It is required to verify both opposite-unit DGs OPERABLE within 1 hour and to continue this action once per 24 hours thereafter until restoration of the required DG is accomplished. This verification provides assurance that opposite-unit DGs are capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

BASES

ACTIONS (continued)

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days ~~72 hours~~. This could lead to a total of 17 days ~~144 hours~~, since initial failure to meet the LCO, to restore the required qualified circuit(s). At this time, a DG could again become inoperable, the circuit(s) restored OPERABLE, and an additional 14 days ~~72 hours~~ (for a total of 31 ~~9~~ days) allowed prior to complete restoration of the LCO. The 17 ~~6~~ day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 ~~6~~ day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1 (see attached)

B.~~1~~2

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the required qualified circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a required qualified circuit fails to pass SR 3.8.1.1, it is inoperable, and additional Conditions and Required Actions apply.

BASES

ACTIONS (continued)

B.~~2~~3

Required Action B.~~2~~3 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features (i.e., systems, subsystems, trains, components, and devices) are designed with redundant safety related trains. This includes the diesel driven auxiliary feedwater pump. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.~~2~~3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required redundant feature(s) results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

BASES

ACTIONS (continued)

In this Condition, the remaining OPERABLE DG and qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.~~3~~4.1 and B.~~3~~4.2

Required Action B.~~3~~4.1 provides F an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition ~~E~~ of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.~~3~~4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.~~3~~4.1 or B.~~3~~4.2, the Problem Identification and Investigation Procedure will continue to evaluate the common cause possibility and determine the need for any additional DG testing. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. ~~7~~8), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

BASES

ACTIONS (continued)

B.~~4~~ 5

According to ~~Regulatory Guide 1.93 (Ref. 6)~~ Reference 7, operation may continue in Condition B for a period that should not exceed ~~72 hours.~~ 14 days.

Insert 1

In Condition B, the remaining OPERABLE DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The ~~72 hour~~ 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.~~4~~ 5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a required qualified circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the DG. At this time, a required qualified circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9 days~~ 20 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour~~ 14 day and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.~~2~~ 3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1

(See Insert 2)

Insert 1

This Completion Time is based upon a risk-informed assessment that concluded that the associated risk is acceptable based upon the availability of the offsite power sources and the onsite standby power sources (i.e., the DGs), and the implementation of a Configuration Risk Management Program.

Insert 2

C.1

The 72 hour Completion Time is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7).

In Condition C, with an opposite-unit DG inoperable, the remaining OPERABLE unit-specific DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC Sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

~~C~~D.1

With one or more buses with both of its required qualified circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the required qualified circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available required qualified circuits two less than required by the LCO, operation may continue for 24 hours. If two required qualified circuits are restored within 24 hours, unrestricted operation may continue. If only one required qualified circuit is restored within 24 hours, power operation continues in accordance with Condition A.

~~D~~E.1 and ~~D~~E.2

In Condition ~~D~~E, with one DG inoperable and one or more buses with one qualified circuit inoperable or with one DG and one bus with both qualified circuits inoperable, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition ~~C~~D. This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time to restore the DG or the required qualified circuit(s) takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the ~~D~~ E Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition ~~D~~ E are modified by a Note to indicate that when Condition ~~D~~ E is entered with no AC source to any division (one or more divisions de-energized), the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition ~~D~~ E to provide requirements for the loss of one DG and one required qualified circuit on one or more buses, without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition ~~D~~ E for a period that should not exceed 12 hours.

F ~~E~~.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

BASES

ACTIONS (continued)

~~F~~ G.1 and ~~F~~ G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

~~G~~ H.1

Condition ~~G~~ H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies may be lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown. Examples of inoperabilities that require entry into Condition ~~G~~ H are: 1) both DGs inoperable and both qualified circuits inoperable on one bus, and 2) one DG inoperable and both qualified circuits inoperable on one bus and one qualified circuit inoperable on the second bus.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. ~~8~~ 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. ~~10~~ 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to reduce stress and wear on diesel engines, a modified start is used in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of starts in accordance with SR 3.8.1.2.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from normal standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see SR Note) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is also addressed in SR 3.8.1.2 Note.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. ~~7~~ 8). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. ~~10~~ 11). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The single largest post-accident load associated with each DG is the Essential Service Water (SX) pump (1290 brake horsepower, 1034 kW at full load conditions). This Surveillance is accomplished by simultaneously tripping loads supplied by the DG which have a minimum combined load equivalent to the single largest post-accident load. This method is employed due to the difficulty of attaining SX full load conditions during normal plant operations.

As required by IEEE-308 (Ref. ~~9~~ 10), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint (64.5 Hz), or 15% above synchronous speed (69 Hz), whichever is lower.

The voltage and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a ~~two Notes.~~ Note ~~1~~ which states that momentary transients (e.g., due to changing bus loads) do not invalidate this test. ~~The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.~~

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Alternatively, the DG can be operated until operating temperatures have stabilized. Note 2 states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. ~~8~~ 10), paragraph 6.2.6(2).

The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. UFSAR, Chapter 8.

3. Regulatory Guide 1.9, Rev. 3, July 1993.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 15.

6. Regulatory Guide 1.93, Rev. 0, December 1974.

7. R.M. Krich to NRC Document Control Desk Letter, "Request for Amendment to Technical Specifications Extension of Allowable Completion Times and Surveillance Requirement Change for Emergency Diesel Generators," January 20, 2000.

8. ~~7.~~ Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

9. ~~8.~~ 10 CFR 50, Appendix A, GDC 18.

10. ~~9.~~ IEEE Standard 308-1978.

11. ~~10.~~ Regulatory Guide 1.137, Rev. 1, October 1979.

ATTACHMENT B-3

INCORPORATED PROPOSED CHANGES

BRAIDWOOD STATION

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

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 <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)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Verify both opposite-unit DGs OPERABLE.	1 hour AND Once per 24 hours thereafter
	AND		
	B.2	Perform SR 3.8.1.1 for the required qualified circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	B.3	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.4.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.4.2	Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 Restore DG to OPERABLE status.	14 days AND 17 days from discovery of failure to meet LCO
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1 Restore DG to OPERABLE status.	72 hours
D. One or more buses with two required qualified circuits inoperable.	D.1 Restore one required qualified circuit per bus to OPERABLE status.	24 hours
E. One DG inoperable and one or more buses with one required qualified circuit inoperable. OR One DG inoperable and one bus with two required qualified circuits inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition E is entered with no AC power source to a division. ---------------------------- E.1 Restore required qualified circuit(s) to OPERABLE status. OR E.2 Restore DG to OPERABLE status.	 12 hours 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Two DGs inoperable.	F.1 Restore one DG to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition A, C, D, E, or F not met. <u>OR</u> Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.5 not met.	G.1 Be in MODE 3. <u>AND</u> G.2 Be in MODE 5.	6 hours 36 hours
H. Two DGs inoperable, and one or more buses with one or more required qualified circuits inoperable. <u>OR</u> One DG inoperable, one bus with two required qualified circuits inoperable, and the second bus with one or more required qualified circuits inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required qualified circuit.	7 days
SR 3.8.1.2	-------------------NOTE------------------- A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. Performance of SR 3.8.1.7 satisfies this SR. -- Verify each DG starts from standby condition and achieves steady state voltage ≥ 3950 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	31 days
SR 3.8.1.3	-------------------NOTES------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This Surveillance shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. -- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 4950 kW and ≤ 5500 kW.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify each day tank contains ≥ 450 gal of fuel oil.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	31 days
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank(s) to the day tank.	31 days
SR 3.8.1.7	Verify each DG starts from normal standby condition and achieves in ≤ 10 seconds, voltage ≥ 3950 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.8	Verify manual transfer of AC power sources from the required normal qualified circuit(s) to the reserve required qualified circuit(s).	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds achieves voltage ≥ 3950 V and ≤ 4580 V; b. In ≤ 10 seconds achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	18 months
SR 3.8.1.13	Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except: a. Engine overspeed; and b. Generator differential current.	18 months
SR 3.8.1.14	-------------------NOTE------------------- Momentary transients outside the load range do not invalidate this test. -- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 5775 kW and ≤ 6050 kW; and b. For the remaining hours of the test loaded ≥ 4950 kW and ≤ 5500 kW.	18 months

(continued)

BASES

ACTIONS (continued)

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the required qualified circuit(s). At this time, a DG could again become inoperable, the circuit(s) restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

The 14 day Completion Time for Required Action B.5 is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7). It is required to verify both opposite-unit DGs OPERABLE within 1 hour and to continue this action once per 24 hours thereafter until restoration of the required DG is accomplished. This verification provides assurance that both opposite-unit DGs are capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

BASES

ACTIONS (continued)

B.2

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the required qualified circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a required qualified circuit fails to pass SR 3.8.1.1, it is inoperable, and additional Conditions and Required Actions apply.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features (i.e., systems, subsystems, trains, components, and devices) are designed with redundant safety related trains. This includes the diesel driven auxiliary feedwater pump. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

BASES

ACTIONS (continued)

Discovering one required DG inoperable coincident with one or more inoperable required redundant feature(s) results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition F of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

BASES

ACTIONS (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the Problem Identification and Investigation Procedure will continue to evaluate the common cause possibility and determine the need for any additional DG testing. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

B.5

According to Reference 7, operation may continue in Condition B for a period that should not exceed 14 days. This Completion Time is based upon a risk-informed assessment that concluded that the associated risk is acceptable based upon the availability of the offsite power sources and the onsite standby power sources (i.e., the DGs), and the implementation of a Configuration Risk Management Program.

In Condition B, the remaining OPERABLE DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

The second Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a required qualified circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DG. At this time, a required qualified circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1

The 72 hour Completion Time is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7).

In Condition C, with an opposite-unit DG inoperable, the remaining OPERABLE unit-specific DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

D.1

With one or more buses with both of its required qualified circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the required qualified circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available required qualified circuits two less than required by the LCO, operation may continue for 24 hours. If two required qualified circuits are restored within 24 hours, unrestricted operation may continue. If only one required qualified circuit is restored within 24 hours, power operation continues in accordance with Condition A.

E.1 and E.2

In Condition E, with one DG inoperable and one or more buses with one qualified circuit inoperable or with one DG and one bus with both qualified circuits inoperable, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition D. This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time to restore the DG or the required qualified circuit(s) takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no AC source to any division (one or more divisions de-energized), the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of one DG and one required qualified circuit on one or more buses, without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition E for a period that should not exceed 12 hours.

F.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

BASES

ACTIONS (continued)

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies may be lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown. Examples of inoperabilities that require entry into Condition H are: 1) both DGs inoperable and both qualified circuits inoperable on one bus, and 2) one DG inoperable and both qualified circuits inoperable on one bus and one qualified circuit inoperable on the second bus.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

Each SR 3.8.1.2 and SR 3.8.1.7 DG start requires the DG to achieve and maintain a steady state voltage and frequency range. The start signals used for this test may consist of one of the following signals:

a. Manual;

b. Simulated loss of ESF bus voltage by itself;

c. Simulated loss of ESF bus voltage in conjunction with an ESF actuation test signal; or

d. An ESF actuation test signal by itself.

For the purpose of SR 3.8.1.2 testing, the DGs are started from standby conditions once per 31 days. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer's recommended operating range (low lube oil and jacket water temperature alarm settings to the high lube oil and jacket water temperature alarm settings).

For the purposes of SR 3.8.1.7 testing, the DGs are started from normal standby conditions once per 184 days. Normal standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained within the prescribed temperature bands of these subsystems when the diesel generator has been at rest for an extended period of time with the prelube oil and jacket water circulating systems operational. The prescribed temperature band is 115°F - 135°F which accounts for instrument tolerances. DG starts for these Surveillances are followed by a warmup period prior to loading.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to reduce stress and wear on diesel engines, a modified start is used in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of starts in accordance with SR 3.8.1.2.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from normal standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see SR Note) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is also addressed in SR 3.8.1.2 Note.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 8). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures.

Although no power factor requirements are established by this SR, the DG is normally operated between 0 and 1000 kVARs. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients (e.g., changing bus loads) do not invalidate this test. Similarly, momentary kVAR transients outside of the specified range do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 11). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required (one of two transfer pumps per DG is "required" to support DG OPERABILITY) fuel oil transfer pump operates and transfers fuel oil from its associated storage tank(s) to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that one pump will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing. Therefore, a 31 day Frequency is appropriate.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine/generator response under the simulated test conditions. This test simulates a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. Note 1 states that momentary transients above the stated voltage limit immediately following a load rejection (i.e., the DG full load rejection) do not invalidate this test. The momentary transient is that which occurs immediately after the circuit breaker is opened, lasts a few milliseconds, and may or may not be observed on voltage recording or monitoring instrumentation. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

In general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time, and maintain a steady state voltage and frequency range.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or Residual Heat Removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, recommends demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load band equivalent to 105% to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are also applicable to this SR.

Although no power factor requirements are established by this SR, a portion of the testing is performed between 0 and 1000 kVARs. The practice of performing this entire test at rated power factor has been determined to be unjustified, potentially destructive, testing due to exceeding the vendors recommendation for maximum voltage of the generator if the DG output breaker should open during testing. Therefore, the DG is to be operated at rated power factor for only a short duration during the performance of this surveillance in accordance with the following guidance:

During the period that the DG is loaded at ≥ 5500 kW and ≤ 1000 kVAR, the following shall be performed once to verify DG operability at rated power factor:

a. Over a two minute period, raise kVAR loading to 4125 kVAR;

b. Operate the DG at 4125 kVAR for 1 minute or until kVAR and kW loading has stabilized; and

c. Reduce kVAR loading to ≤ 1000 kVAR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a Note which states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

<u>SR 3.8.1.15</u>

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Alternatively, the DG can be operated until operating temperatures have stabilized. Note 2 states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 10), paragraph 6.2.6(2).

The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by the automatic load sequence timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by a Note. The reason for the Note is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. R. M. Krich to NRC Document Control Desk Letter, "Request for Amendment to Technical Specifications, to Facility Operating Licenses, Emergency Diesel Generators, Completion Time Extension and Surveillance Requirement Change," January 20, 2000.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
9. 10 CFR 50, Appendix A, GDC 18.
10. IEEE Standard 308-1978.
11. Regulatory Guide 1.137, Rev. 1, October 1979.

ATTACHMENT B-4

INCORPORATED PROPOSED CHANGES

BYRON STATION

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

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 <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)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Verify both opposite-unit DGs OPERABLE.	1 hour AND Once per 24 hours thereafter
	AND		
	B.2	Perform SR 3.8.1.1 for the required qualified circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	B.3	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.4.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.4.2	Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 Restore DG to OPERABLE status.	14 days AND 17 days from discovery of failure to meet LCO
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1 Restore DG to OPERABLE status.	72 hours
D. One or more buses with two required qualified circuits inoperable.	D.1 Restore one required qualified circuit per bus to OPERABLE status.	24 hours
E. One DG inoperable and one or more buses with one required qualified circuit inoperable. OR One DG inoperable and one bus with two required qualified circuits inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition E is entered with no AC power source to a division. ---------------------------- E.1 Restore required qualified circuit(s) to OPERABLE status. OR E.2 Restore DG to OPERABLE status.	 12 hours 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Two DGs inoperable.	F.1	Restore one DG to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition A, C, D, E, or F not met. OR Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.5 not met.	G.1 AND G.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours
H. Two DGs inoperable, and one or more buses with one or more required qualified circuits inoperable. OR One DG inoperable, one bus with two required qualified circuits inoperable, and the second bus with one or more required qualified circuits inoperable.	H.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required qualified circuit.	7 days
SR 3.8.1.2	-------------------NOTE------------------- A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. Performance of SR 3.8.1.7 satisfies this SR. --- Verify each DG starts from standby condition and achieves steady state voltage ≥ 3950 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	31 days
SR 3.8.1.3	-------------------NOTES------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This Surveillance shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. --- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 4950 kW and ≤ 5500 kW.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify each day tank contains ≥ 450 gal of fuel oil.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	31 days
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank(s) to the day tank.	31 days
SR 3.8.1.7	Verify each DG starts from normal standby condition and achieves in ≤ 10 seconds, voltage ≥ 3950 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.8	Verify manual transfer of AC power sources from the required normal qualified circuit(s) to the reserve required qualified circuit(s).	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds achieves voltage ≥ 3950 V and ≤ 4580 V; b. In ≤ 10 seconds achieves frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	18 months
SR 3.8.1.13	Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except: a. Engine overspeed; and b. Generator differential current.	18 months
SR 3.8.1.14	-------------------NOTE------------------- Momentary transients outside the load range do not invalidate this test. -- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 5775 kW and ≤ 6050 kW; and b. For the remaining hours of the test loaded ≥ 4950 kW and ≤ 5500 kW.	18 months

(continued)

BASES

ACTIONS (continued)

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the required qualified circuit(s). At this time, a DG could again become inoperable, the circuit(s) restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

The 14 day Completion Time for Required Action B.5 is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7). It is required to verify both opposite-unit DGs OPERABLE within 1 hour and to continue this action once per 24 hours thereafter until restoration of the required DG is accomplished. This verification provides assurance that both opposite-unit DGs are capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

BASES

ACTIONS (continued)

B.2

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the required qualified circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a required qualified circuit fails to pass SR 3.8.1.1, it is inoperable, and additional Conditions and Required Actions apply.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features (i.e., systems, subsystems, trains, components, and devices) are designed with redundant safety related trains. This includes the diesel driven auxiliary feedwater pump. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

BASES

ACTIONS (continued)

Discovering one required DG inoperable coincident with one or more inoperable required redundant feature(s) results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition F of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

BASES

ACTIONS (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the Problem Identification and Investigation Procedure will continue to evaluate the common cause possibility and determine the need for any additional DG testing. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

B.5

According to Reference 7, operation may continue in Condition B for a period that should not exceed 14 days. This Completion Time is based upon a risk-informed assessment that concluded that the associated risk is acceptable based upon the availability of the offsite power sources and the onsite standby power sources (i.e., the DGs), and the implementation of a Configuration Risk Management Program.

In Condition B, the remaining OPERABLE DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

The second Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a required qualified circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DG. At this time, a required qualified circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1

The 72 hour Completion Time is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7).

In Condition C, with an opposite-unit DG inoperable, the remaining OPERABLE unit-specific DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

D.1

With one or more buses with both of its required qualified circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the required qualified circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available required qualified circuits two less than required by the LCO, operation may continue for 24 hours. If two required qualified circuits are restored within 24 hours, unrestricted operation may continue. If only one required qualified circuit is restored within 24 hours, power operation continues in accordance with Condition A.

E.1 and E.2

In Condition E, with one DG inoperable and one or more buses with one qualified circuit inoperable or with one DG and one bus with both qualified circuits inoperable, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition D. This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time to restore the DG or the required qualified circuit(s) takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no AC source to any division (one or more divisions de-energized), the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of one DG and one required qualified circuit on one or more buses, without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition E for a period that should not exceed 12 hours.

F.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

BASES

ACTIONS (continued)

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies may be lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown. Examples of inoperabilities that require entry into Condition H are: 1) both DGs inoperable and both qualified circuits inoperable on one bus, and 2) one DG inoperable and both qualified circuits inoperable on one bus and one qualified circuit inoperable on the second bus.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

Each SR 3.8.1.2 and SR 3.8.1.7 DG start requires the DG to achieve and maintain a steady state voltage and frequency range. The start signals used for this test may consist of one of the following signals:

a. Manual;

b. Simulated loss of ESF bus voltage by itself;

c. Simulated loss of ESF bus voltage in conjunction with an ESF actuation test signal; or

d. An ESF actuation test signal by itself.

For the purpose of SR 3.8.1.2 testing, the DGs are started from standby conditions once per 31 days. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer's recommended operating range (low lube oil and jacket water temperature alarm settings to the high lube oil and jacket water temperature alarm settings).

For the purposes of SR 3.8.1.7 testing, the DGs are started from normal standby conditions once per 184 days. Normal standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained within the prescribed temperature bands of these subsystems when the diesel generator has been at rest for an extended period of time with the prelube oil and jacket water circulating systems operational. The prescribed temperature band is 115°F - 135°F which accounts for instrument tolerances. DG starts for these Surveillances are followed by a warmup period prior to loading.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to reduce stress and wear on diesel engines, a modified start is used in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of starts in accordance with SR 3.8.1.2.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from normal standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see SR Note) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is also addressed in SR 3.8.1.2 Note.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 8). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures.

Although no power factor requirements are established by this SR, the DG is normally operated between 0 and 1000 kVARs. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients (e.g., changing bus loads) do not invalidate this test. Similarly, momentary kVAR transients outside of the specified range do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 11). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required (one of two transfer pumps per DG is "required" to support DG OPERABILITY) fuel oil transfer pump operates and transfers fuel oil from its associated storage tank(s) to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that one pump will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing. Therefore, a 31 day Frequency is appropriate.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The single largest post-accident load associated with each DG is the Essential Service Water (SX) pump (1290 brake horsepower, 1034 kW at full load conditions). This Surveillance is accomplished by simultaneously tripping loads supplied by the DG which have a minimum combined load equivalent to the single largest post-accident load. This method is employed due to the difficulty of attaining SX full load conditions during normal plant operations.

As required by IEEE-308 (Ref. 10), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint (64.5 Hz), or 15% above synchronous speed (69 Hz), whichever is lower.

The voltage and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine/generator response under the simulated test conditions. This test simulates a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. Note 1 states that momentary transients above the stated voltage limit immediately following a load rejection (i.e., the DG full load rejection) do not invalidate this test. The momentary transient is that which occurs immediately after the circuit breaker is opened, lasts a few milliseconds, and may or may not be observed on voltage recording or monitoring instrumentation. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

In general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time, and maintain a steady state voltage and frequency range.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or Residual Heat Removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, recommends demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load band equivalent to 105% to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are also applicable to this SR.

Although no power factor requirements are established by this SR, a portion of the testing is performed between 0 and 1000 kVARs. The practice of performing this entire test at rated power factor has been determined to be unjustified, potentially destructive, testing due to exceeding the vendors recommendation for maximum voltage of the generator if the DG output breaker should open during testing. Therefore, the DG is to be operated at rated power factor for only a short duration during the performance of this surveillance in accordance with the following guidance:

During the period that the DG is loaded at ≥ 5500 kW and ≤ 1000 kVAR, the following shall be performed once to verify DG operability at rated power factor:

a. Over a two minute period, raise kVAR loading to 4125 kVAR;

b. Operate the DG at 4125 kVAR for 1 minute or until kVAR and kW loading has stabilized; and

c. Reduce kVAR loading to ≤ 1000 kVAR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a Note which states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

<u>SR 3.8.1.15</u>

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Alternatively, the DG can be operated until operating temperatures have stabilized. Note 2 states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 10), paragraph 6.2.6(2).

The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by the automatic load sequence timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by a Note. The reason for the Note is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. R. M. Krich to NRC Document Control Desk Letter, "Request for Amendment to Technical Specifications, to Facility Operating Licenses, Emergency Diesel Generators, Completion Time Extension and Surveillance Requirement Change," January 20, 2000.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
9. 10 CFR 50, Appendix A, GDC 18.
10. IEEE Standard 308-1978.
11. Regulatory Guide 1.137, Rev. 1, October 1979.

ATTACHMENT C

INFORMATION SUPPORTING A FINDING OF NO SIGNIFICANT HAZARDS CONSIDERATION

According to 10 CFR 50.92 (c), a proposed change to an operating license does not involve a significant hazards consideration if operation of the facility in accordance with the proposed change would not:

- Involve a significant increase in the probability or consequences of an accident previously evaluated; or
- Create the possibility of a new or different kind of accident from any accident previously evaluated; or
- Involve a significant reduction in the margin of safety.

Commonwealth Edison (ComEd) Company proposes changes to Appendix A, Technical Specifications, of Facility Operating License Nos. NPF-72, NPF-77, NPF-37 and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively. The proposed changes are to Technical Specifications (TS) Section 3.8.1, "AC Sources – Operating," and Surveillance Requirement (SR) 3.8.1.14. These proposed changes will extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG). These proposed changes will support on-line maintenance and overhaul of the EDGs. The current Completion Times for restoration of an inoperable EDG are insufficient to support the required maintenance and post-maintenance testing windows. A new Required Action is proposed to be incorporated into the TS to verify the operability of the opposite unit EDGs while the affected EDG is inoperable. These actions ensure the availability of the remaining AC power sources to the affected Engineered Safety Feature (ESF) bus. In addition, the SR corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) is proposed to be revised to allow the surveillance test to be performed during Modes 1 and 2 (i.e., "Power Operation," and "Startup," respectively). This test can then be performed as a post-maintenance verification test subsequent to the EDG overhauls.

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

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

The proposed changes include the extension of the Completion Time for the Emergency Diesel Generators (EDGs) from 72 hours to 14 days to allow on-line preventive maintenance to be performed. Within one hour of declaring the EDG inoperable, the operability of the opposite unit EDGs will be verified. The EDGs are not initiators of previously evaluated postulated accidents. Extending the completion times of the EDGs would not have any impact on the frequency of any accident previously evaluated, and therefore the probability of a previously analyzed accident is unchanged. The proposed change to the Completion Time for EDGs will not result in any changes to the plant activities associated with EDG maintenance, but rather will enable a more efficient planning and scheduling of maintenance activities that will minimize potential adverse interactions with concurrent outage activities.

The consequences of a previously analyzed event are the same during a 72-hour EDG Completion Time as the consequences during a 14-day Completion Time. Thus the consequences of accidents previously analyzed are unchanged between the existing TS requirements and the proposed change. In the worst case scenario, the ability to mitigate the consequences of any accident previously analyzed is preserved. The consequences of an accident are independent of the time the EDGs are out of service. As a general practice, no other additional failures are postulated while equipment is inoperable within its TS Completion Time.

The proposed changes also include a change to TS Surveillance Requirement (SR) 3.8.1.14 that does not result in a significant increase in the probability or consequences of an accident previously evaluated in Chapter 15 of the Byron and Braidwood Stations Updated Final Safety Analysis Report (UFSAR). The probability of an accident is not increased since the EDGs are used to support mitigation of the consequences of an accident. The failure of an EDG while testing is not an assumed initiator of a previously analyzed accident. The consequences of an accident are not increased because testing of the EDG does not affect the remainder of the safety-related equipment analyzed to mitigate the consequences of an accident. Specifically, the EDG breaker control scheme trips the EDG breaker on overcurrent, underfrequency, loss of field, generator neutral ground, and reverse power when there is no safety injection signal present. This logic prevents potential damage of the Emergency Core Cooling System (ECCS) equipment powered by the EDG to ensure that the ECCS equipment is available in the event of an actual safety injection with or without a Loss of Offsite Power (LOOP).

To fully evaluate the effect of the proposed EDG Completion Time extension, Probabilistic Risk Assessment (PRA) methods and deterministic analysis were utilized. The results of the analysis show no significant increase in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF).

Therefore the proposed changes do not involve a significant increase in the probability or consequences of an accident previously analyzed.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed changes do not involve a physical change to the plant. No new equipment is being introduced, and installed equipment is not being operated in a new or different manner except for the following. The proposed changes allow performance of TS SR 3.8.1.14 while in Modes 1 or 2 (i.e., "Power Operation" or "Startup"). The electrical lineup for performing the SR will be the same as the lineup for performance of TS SR 3.8.1.3, which is routinely performed at least once per month for each EDG. The difference between these two SRs is in the duration of the surveillances. SR 3.8.1.3 requires that the EDG be tested in parallel with offsite power for ≥ 60 minutes, whereas proposed SR 3.8.1.14 requires the parallel operation for 24-hours. There is no change being made to the parameters within which the plant is operated. There are no setpoints affected by this proposed change at which protective or mitigative actions are initiated. This proposed change will not alter the manner in which equipment operation is initiated, nor will the function demands on credited equipment be changed. No alteration in the procedures, which ensure that the plant remains within analyzed limits, is being proposed, and no change is being made to the procedures relied upon to respond to an off-normal event. As such, no new failure modes are being introduced. Other than the changes in duration of EDG unavailability from 72 hours to 14 days and on-line testing from 60 minutes to 24 hours, the change does not alter assumptions made in the safety analysis and licensing basis. Therefore, these proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

The proposed changes affect the EDG Completion Time and allow the performance of the 24-hour endurance run at power. The proposed changes will extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable EDG. A new Required Action is proposed to be incorporated into the TS to verify the operability of the opposite unit EDGs while the affected EDG is inoperable. These actions ensure the availability of the remaining Alternating Current (AC) power sources to the affected Engineered Safety Feature (ESF) bus. In addition, the SR corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) is proposed to be revised to allow the surveillance test to be performed during Modes 1 and 2 (i.e., "Power Operation," and "Startup," respectively). This test may then be performed as a post-maintenance verification test subsequent to the EDG overhauls. The proposed changes have been evaluated both deterministically and using a risk-informed approach. The evaluation concluded the following with respect to these proposed changes.

- Applicable regulatory requirements will continue to be met,
- Adequate defense-in-depth will be maintained,
- Sufficient safety margins will be maintained, and
- Any increases in CDF and LERF are small and consistent with the NRC Safety Goal Policy Statement.

Furthermore, increases in risk posed by potential combinations of equipment out of service during the extended Completion Time will be managed under the Configuration Risk Management (CRMP). The following are examples.

- An EDG extended Completion Time will not be entered intentionally for scheduled maintenance purposes if severe weather conditions are expected.
- While in the extended EDG Completion Time, additional elective equipment maintenance or testing or equipment failure will be evaluated using the CRMP. Activities that yield unacceptable results via the CRMP will be avoided.
- The condition of the offsite power supply and switchyard will be evaluated.

Compensatory actions have been identified that can mitigate any increase in risk. Byron and Braidwood Stations will have procedures in place for the following compensatory actions.

ATTACHMENT D

INFORMATION SUPPORTING AN ENVIRONMENTAL ASSESSMENT

Commonwealth Edison (ComEd) Company has evaluated these proposed changes against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. ComEd has determined that these proposed changes meet the criteria for a categorical exclusion set forth in 10 CFR 51.22(c)(9) and as such, has determined that no irreversible consequences exist in accordance with 10 CFR 50.92(b). This determination is based on the fact that these changes are being proposed as an amendment to a license issued pursuant to 10 CFR 50 that changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or that changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria.

(i) The proposed changes involve no significant hazards consideration.

As demonstrated in Attachment C, these proposed changes do not involve any significant hazards consideration.

(ii) There is no significant change in the types or significant increase in the amounts of any effluent that may be released offsite.

The proposed changes to allow performance of Emergency Diesel Generator (EDG) overhauls on-line is consistent with the design basis of the plant. These changes do not result in an increase in power level, does not increase the production, nor alter the flow path or method of disposal of radioactive waste or byproducts. Therefore the proposed changes will not affect the types or increase the amounts of any effluents released offsite.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

The proposed changes will not result in changes in the configuration of the facility. The proposed changes only affect operation of the plant in that EDG preventive maintenance may be performed on-line rather than while shutdown. The EDGs are not located in the Radiological Protection Area, the EDG area dose rate will not change whether the plant is operating or shutdown. The manner in which the maintenance is performed will not be affected by these proposed changes. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from these proposed changes. There will be no change in the level of controls or methodology used for processing radioactive effluents or handling of solid radioactive waste, nor will the proposed changes result in any change in the normal radiation levels within the plant. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from these proposed changes.

ATTACHMENT E

SUMMARY OF THE BYRON AND BRAIDWOOD STATION PROBABILISTIC RISK ASSESSMENT

1. Background

The Byron and Braidwood Stations Individual Plant Examinations (IPEs) were submitted to the NRC by letters dated April 28,1994 and June 30, 1994, respectively, respond to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)." Requests for Additional Information (RAIs) were sent to Commonwealth Edison (ComEd) Company by the NRC on January 26, 1996, for Braidwood Station and February 1, 1996, for Byron Station. The requests identified concerns that were similar to those raised previously by the NRC for the Zion Nuclear Power Station IPE. As a result of the RAIs, Modified IPEs were developed for the Byron and Braidwood Stations and submitted to the NRC on March 27,1997. The Modified IPEs included the 4kV ESF Bus cross-tie procedure enhancements discussed in the original IPEs.

The Modified IPEs were approved by the NRC by letters dated December 3, 1997, for Byron Station and October 27, 1997, for Braidwood Station. The NRC letters noted that the Modified IPE submittals met the intent of Generic Letter 88-20.

The current Byron and Braidwood Stations PRAs were prepared by major upgrades and updates of the Modified IPEs. The following section highlights changes to the Modified IPEs made during the development of the Probabilistic Risk Assessment (PRA) upgrades.

2. Changes To The Modified IPEs

An overview of the upgrades that have been made to the Braidwood and Byron Stations PRAs since the Modified IPEs were submitted is provided in Table E2-1. Some of the more significant enhancements are discussed below.

2.1 Conversion To Linked Fault Tree Models

Significant changes were made to the logic models in the PRA updates. The models were changed from a support state methodology to a linked fault tree methodology using Computer Aided Fault Tree Analysis (CAFTA). One of the benefits of this methodology is the ability to calculate the importance of specific components or groups of components to the overall risk of the plant.

Given that the performance of the front line mitigation systems is highly dependent upon the performance of those systems supporting their operation, combining (i.e., linking) a front line system to its support system creates a "complete" system model. All known combinations of failures of the front line systems, including those due to support systems failures, are modeled. The resulting fault tree model is a "large" fault tree.

The majority of industry IPEs and PRAs currently performed employ fault tree linking. Major industry resources have been devoted to the development of software for large fault tree quantification. Examples include the Electric Power Research Institute (EPRI) Risk and Reliability Workstation and the Integrated Risk and Reliability System developed by the Idaho National Engineering and Environmental Laboratories (INEEL) under NRC sponsorship. The developments in quantifying these complex fault trees are such that the computation time currently is in terms of minutes. Given these considerations, the modified IPE model was converted to a linked fault tree model from a support state model.

2.2 Event Trees

The following event trees are represented in the Byron and Braidwood Station PRAs:

- General Transient;
- Loss of a Direct Current (DC) Bus Transient Event Tree;
- Anticipated Transients Without Scram (ATWS);
- Secondary Line Break Inside Containment;
- Secondary Line Break Outside Containment;
- Single Unit and Dual Unit Loss of Offsite Power (LOOP, DLOOP);
- Steam Generator Tube Rupture (SGTR);
- Excessive LOCA (i.e., Vessel rupture) (XLOCA);
- Large Break Loss of Coolant Accident (LLOCA);
- Medium Break Loss of Coolant Accident (MLOCA);
- Small Break Loss of Coolant Accident, Isolable and Non-Isolable (SLOCA); and
- Interfacing Systems LOCA Outside Containment (ISLOCA).

The XLOCA and ISLOCA event trees are mapped directly to core damage.

Table E2-1
Summary of Major Changes in Current PRA Models for Braidwood and Byron Stations

PRA Elements	Summary of Major Changes
Initiating Events Analysis	• Failure Modes and Effects Analysis (FMEA) of support systems performed • Some initiating events added • Fault trees developed for selected support system initiators
Event Sequence Modeling	• Converted from support state to linked fault tree • Most event trees updated and revised • Extensive review and revisions to success criteria
Success Criteria and Thermal Hydraulic Analysis	• 1200°F core exit temperature core damage definition • Many new Modular Accident Analysis Program (MAAP) runs made • NUREG-4550 "Analysis of Core Damage Frequency: Internal Events Methodology, Vol. 1, Rev. 1, January 1990," Seal LOCA model adopted and integrated with updated offsite power recovery model
Systems Analysis	• New models developed for selected support system initiators • All existing fault trees reviewed, updated and revised per new design freeze date • Some new fault trees developed
Common Cause Analysis	• An updated procedures guide for Common Cause Failure Analysis (CCFA) was developed • Many common cause events added to fault trees • INEEL data was used to update generic estimates of Common Cause Failure (CCF) probabilities using MGL method • New models developed for asymmetric CCF configurations • Plant specific analysis of data for high risk events
Human Reliability Analysis	• Updated procedures guide for Human Reliability Analysis (HRA) developed using up to date methodology • Extensive re-analysis and many new events to analyze • Comprehensive review and re-quantification of dependent human actions where appropriate • Updated offsite power recovery analysis which delineates between dual and single unit LOOP
Data Analysis	• Updated procedures guide for data analysis • Incorporated plant specific experience from maintenance rule program • Updated generic data for failure rates and initiating events • Performed Bayes updates
Internal Flooding Analysis	• Essential Service Water (SX) pipe break frequencies updated • Non-pipe flooding sources included • Detailed FMEA performed to establish isolation capabilities • HRA updated for consistency with remaining sequences
Level 1 CDF Quantification	• Single top CDF model quantified using CAFTA
Level 2 LERF Quantification	• Used methodology in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." • Single top Large Early Release Fraction (LERF) model quantified using CAFTA

2.3 Initiating Event Revisions

The initiating event analysis was revised to take advantage of recent industry data. The revision also documented a systematic search and categorization for initiating events in preparation for the Byron and Braidwood Stations PRA certification effort. Plant response modeling was enhanced with the addition of several new initiating events and associated logic structures. New initiating events included Loss of 120 VAC Instrument Bus, loss of all Non-Essential Service Water System, XLOCA (i.e., Reactor Vessel Rupture) and a SLOCA. SGTR and Secondary Line Breaks Inside Containment were split into steam generator specific initiators. Similarly, Loss of Condenser Heat Sink and Total Loss of Feedwater were extracted from the General Transient initiator logic and modeled. The following highlights the changes.

- The latest industry data for transient events was taken from NUREG/CR-5750, "Rates of Initiating Events at U. S. Nuclear Power Plants: 1987-1995," dated February 1999 and prepared by Idaho National Engineering and Environmental Laboratory (INEEL). This study categorizes industry events for the period 1987 through 1995. Using NUREG/CR-5750, the transient initiator was redefined such that the total loss of feedwater and the loss of the condenser heat sink were removed from the general transient initiator and treated separately. Additionally, more realistic estimates of LOCA frequencies have been generated based on improved metallurgical knowledge and fracture mechanics associated with pipe breaks.

- System fault trees were used to calculate the frequency for loss of component cooling water, single and dual unit losses of the Essential Service Water System, and loss of Non-Essential Service Water System. These events can vary greatly due to plant design. A system fault tree model was developed to capture plant specific design features and failure modes. The fault tree quantification algorithm was properly modified to calculate an initiating event frequency instead of a probability.

- NUREG/CR-5750 was also used to estimate support system initiators for the loss of DC buses and Alternating Current (AC) instrument buses. The "Loss of 4kV Bus" initiators were eliminated from the model since the modified IPE demonstrated these initiators were negligible contributors to CDF.

- The ISLOCA frequency calculation was revised using uncertainty distributions and Monte Carlo sampling to account for the uncertainties and the state of knowledge dependencies between failure rates for like components such as check valves. This caused a small increase in the ISLOCA frequency.

- Given its importance in the modified IPE, the pipe rupture frequency for the Essential Service Water System was recalculated to represent the latest industry state of knowledge. Two databases were used to support the updated assessment. One database was from Electric Power Research Institute (EPRI) Technical Report (TR)-111880, "Piping System Failure Rates and Rupture Frequencies for Use in Risk-Informed Inservice Inspection Applications," dated September 1999. The other database was sponsored by the Swedish Nuclear Power Inspectorate, (i.e., SKI). The database of historical events in the EPRI database was supplemented by the SKI database and was limited to events in the United States not included in the EPRI database. The recovery analysis in the previous study was updated to provide more realistic assumptions about the times available for recovery actions, which in turn reflect more realistic assumptions about the size of the leak areas from the Essential Service Water piping system components that represent sources of flooding. This updated analysis of Essential Service Water pump flooding scenarios confirmed the findings of the Modified IPE that supported a decision to implement plant modifications to reduce the risk impact of these scenarios.

The PRA models used to support those proposed changes have been modified to represent completion of the plant modifications, procedure changes to improve flood detection and isolation, and maintenance improvements to certain Essential Service Water System Valves to reduce the risk contribution from auxiliary building flooding.

- The PRA models distinguish between LOOP events that impact each unit singly and those that impact both units concurrently. This was done to properly treat the dependencies between the cause of the initiating event and the probability of implementing the unit cross-ties. The LOOP and DLOOP initiating event frequencies and recovery curves were recalculated using industry data from NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," dated November, 1998, with Bayesian updates for Byron and Braidwood Stations site specific events. The LOOP and DLOOP initiators were partitioned into momentary (i.e., recovered within two minutes) and sustained events.

- Industry data was also used in conjunction with the NUERG-1150, "Severe Accident Risks: An assessment for Five U.S. Nuclear Power Plants," October 1990, RCP Seal LOCA model, applied on a plant specific basis, to evaluate the probability of offsite power recovery before core damage for LOOP sequences. The times to core uncovery use a probabilistic characterization of RCP leak sizes from the expert elicitation results in NUREG-1150, and plant specific Modular Accident Analysis Program (MAAP) analyses that calculate times to core damage for a spectrum of plant conditions that are represented in the PRA event trees. The model also considers dependent effects of battery depletion on the ability to stabilize plant conditions during Station Black-out (SBO) scenarios. The electric power non-recovery models derived from these models were carefully applied on a cutset-by-cutset basis to ensure that dependencies were adequately addressed.

Tables E2-2-BY and E2-2-BW list the initiating events and their frequencies for the Byron and Braidwood Stations PRAs and compares the current frequencies to those used in the IPEs.

2.4 Human Reliability Analysis Update

For the modified IPEs, selected operator actions had been re-analyzed using the EPRI Cause Based Decision Tree Methodology (CBDTM) from EPRI TR-100259, "An Approach to the Analysis of Operator Actions in PRAs," dated June 1992. The modified IPE HRA modeled late 1996 Byron and Braidwood Station staffing, procedures, and practices and included a comprehensive analysis of pre-initiators.

The HRA was updated in 1997 and 1998 using plant procedures then in effect and completely revised to apply to the linked fault tree PRA model under development. All type C (i.e., post-initiator) operator actions were re-evaluated and additional operator actions were identified which required evaluation. The HRA was independently reviewed in late 1998 to complete the update. The scope of work included the analysis and documentation of new human actions added to the PRA models and revisions to current analysis files where appropriate.

A careful analysis was made to ensure that application of human action non-recovery probabilities take into account sequence dependent and cutset dependent factors that could influence the human error rates. This required application of many of the recoveries on a cutset-by-cutset basis. It also required a careful evaluation to ensure that potentially significant dependent human actions were not masked from the cutset truncation process.

2.5 Data Collection and Analysis Update

The failure data used to obtain estimates of the failure rates and equipment unavailability was updated to include recent plant experience through the end of 1997. Similar to other PRA elements, the effort was done in such a way to conform to current industry practice and NRC guidance. Collection and analysis of recent plant data was limited to key components that were initially found to be among the most important in terms of potential impact on system or core damage failure probabilities.

Consistent with NRC guidance and industry practice, this data was used to develop failure probabilities and maintenance component unavailability using a statistical technique known as Bayesian updating. This updating process is a formal mathematical method for combining generic estimates with plant specific evidence. Since generic estimates are needed for a number of components that have not experienced failures at the plant, and Bayesian updating requires the use of a "prior" estimate, then plant-specific evidence can be applied on an as needed basis or as resources allow.

Table E2-2-BY
Byron Station Initiating Event Categories and Frequencies

Event Tree		Initiating Event	Point Estimate (Per Year) PRA	IPE
XLOCA	1.	Excessive LOCA (i.e., Vessel Rupture)	2.66E-7	NA
LLOCA	2.	Large LOCA	7.54E-6	3.00E-4
MLOCA	3.	Medium LOCA	1.08E-5	8.00E-4
	4.	Small LOCA		6.10E-3
SLOCA		a. Non-isolable	1.40E-3	
TRANS		b. Isolable (Pressurizer Power Operated Relief Valve fails open)	1.01E-3	
ISLOCA	5.	Interfacing Systems LOCA	4.05E-7	1.01E-7
	6.	Steam Generator Tube Rupture		1.10E-2
SGTR		Steam Generator Tube Rupture (per SG)	1.49E-3	
TRANS	7.	General Transient*	1.01	2.20E+0
TRANS	8.	Loss of Condenser Heat Sink*	9.45E-2	NA
TRANS	9.	Total Loss of Feedwater – Recoverable*	4.47E-2	NA
TRANS	10.	Total Loss of Feedwater – Non-recoverable*	2.49E-2	NA
SLB	11.	Steamline Break Inside Containment (per SG)*	2.10E-4	1.80E-3
SLB	12.	Steamline Break Outside Containment*	1.75E-3	1.80E-3
SLB	13.	Feedline Break Inside Containment (per SG)*	2.10E-4	1.80E-3
LOOP	14.	Loss of Offsite Power (Single Unit) – Momentary	2.11E-3	
LOOP	15.	Loss of Offsite Power (Single Unit) – Sustained	1.89E-2	3.22E-2
DLOOP	16.	Loss of Offsite Power (Dual Unit) – Momentary	4.74E-3	
DLOOP	17.	Loss of Offsite Power (Dual Unit) - Sustained	1.72E-2	1.21E-2
	18.	Loss of One DC Bus*		
TRANS		a. Loss of DC Bus 111	2.91E-4	5.05E-4
TRANS		b. Loss of DC Bus 112	2.91E-4	NA
	19.	Loss of a 120V AC Instrument Bus*		
TRANS		a. Loss of AC Bus 111	7.28E-4	NA
TRANS		b. Loss of AC Bus 112	7.28E-4	NA
TRANS		c. Loss of AC Bus 113	7.28E-4	NA
TRANS		d. Loss of AC Bus 114	7.28E-4	NA
TRANS	20.	Loss of Non-Essential Service Water	4.46E-2	NA
TRANS	21.	Loss of Instrument Air*	1.08E-2	4.30E-4
TRANS	22.	Loss of Component Cooling Water	5.35E-5	5.62E-5
	23.	Single Unit Loss of Essential Service Water (Non-recoverable)	4.44E-5	4.64E-4
	24.	Single Unit Loss of Essential Service Water (Recoverable)	2.18E-3	
TRANS	25.	Dual Unit Loss of Essential Service Water (Non-recoverable)	1.54E-5	9.59E-6
TRANS	26.	Dual Unit Loss of Essential Service Water (Recoverable)	7.54E-4	
	27.	Internal Flood Zones		
TRANS		a. Unit 1 Turbine Building, Grade Level (Zone 8.3-1)	1.48E-8	1.30E-4
TRANS		b. Unit 2 Turbine Building, Grade Level (Zone 8.3-2)	1.48E-8	NA
TRANS		c. Auxiliary Building Elevation 426 (Zone 11.6-0)	1.89E-5	1.89E-5

* An availability factor of 0.84 was used for Byron Station.

Table E2-2-BW
Braidwood Station Initiating Event Categories and Frequencies

Event Tree	Initiating Event	Point Estimate (Per Year) PRA	IPE
XLOCA	1. Excessive LOCA (i.e., Vessel Rupture)	2.66E-7	NA
LLOCA	2. Large LOCA	7.54E-6	3.00E-4
MLOCA	3. Medium LOCA	1.08E-5	8.00E-4
	4. Small LOCA		6.30E-3
SLOCA	a. Non-isolable	1.40E-3	
TRANS	c. Isolable (Pressurizer Power Operated Relief Valve fails open)	1.01E-3	
ISLOCA	5. Interfacing Systems LOCA	4.05E-7	1.01E-7
	6. Steam Generator Tube Rupture		1.10E-2
SGTR	Steam Generator Tube Rupture (per SG)	1.42E-3	
TRANS	7. General Transient*	9.60E-1	3.00
TRANS	8. Loss of Condenser Heat Sink*	1.25E-1	NA
TRANS	9. Total Loss of Feedwater – Recoverable*	3.08E-2	NA
TRANS	10. Total Loss of Feedwater – Non-recoverable*	1.79E-2	NA
SLB	11. Steamline Break Inside Containment (per SG)*	2.00E-4	1.80E-3
SLB	12. Steamline Break Outside Containment*	1.66E-3	1.80E-3
SLB	13. Feedline Break Inside Containment (per SG)*	2.00E-4	1.80E-3
LOOP	14. Loss of Offsite Power (Single Unit) – Momentary	2.12E-3	
LOOP	15. Loss of Offsite Power (Single Unit) – Sustained	2.97E-2	3.22E-2
DLOOP	16. Loss of Offsite Power (Dual Unit) – Momentary	4.74E-3	
DLOOP	17. Loss of Offsite Power (Dual Unit) – Sustained	2.23E-2	1.32E-2
	18. Loss of One DC Bus*		
TRANS	a. Loss of DC Bus 111	2.77E-4	5.05E-4
TRANS	b. Loss of DC Bus 112	2.77E-4	NA
	19. Loss of a 120V AC Instrument Bus*		
TRANS	a. Loss of AC Bus 111	6.93E-4	NA
TRANS	b. Loss of AC Bus 112	6.93E-4	NA
TRANS	c. Loss of AC Bus 113	6.93E-4	NA
TRANS	d. Loss of AC Bus 114	6.93E-4	NA
TRANS	20. Loss of Non-Essential Service Water	1.03E-2	NA
TRANS	21. Loss of Instrument Air*	1.03E-2	4.30E-4
TRANS	22. Loss of Component Cooling Water	1.25E-4	5.91E-5
	23. Single Unit Loss of Essential Service Water (Non-recoverable)	3.66E-5	4.64E-4
	24. Single Unit Loss of Essential Service Water (Recoverable)	1.79E-3	
TRANS	25. Dual Unit Loss of Essential Service Water (Non-recoverable)	2.24E-5	5.58E-6
TRANS	26. Dual Unit Loss of Essential Service Water (Recoverable)	1.10E-3	
	27. Internal Flood Zones		
TRANS	a. Unit 1 Turbine Building, Grade Level (Zone 8.3-1)	1.48E-8	1.30E-4
TRANS	b. Unit 2 Turbine Building, Grade Level (Zone 8.3-2)	1.48E-8	NA
TRANS	c. Auxiliary Building Elevation 426 (Zone 11.6-0)	1.89E-5	1.89E-5

* An availability factor of 0.80 was used for Braidwood Station.

The industry data was taken from recognized sources. The preferred source was the EPRI Advanced Light Water Reactor (ALWR) failure rate database in NP-6780-L, "EPRI ALWR Utility Requirements," Volume II, "ALWR Evolutionary Plant," Chapter 1, Appendix A, "Key PRA Assumptions and Groundrules," Revision 1, issued on August 31, 1990.

A comprehensive update of common cause failure treatment was performed. The system fault trees were revised to account for a more complete treatment of common cause basic events in the model, including common cause failures of normally operating equipment that could cause an initiating event. The Multiple Greek Letter (MGL) method was applied to quantify common cause basic event probabilities. The most recent NRC sponsored common cause data base was used to update generic estimates for MGL model parameters. Plant specific screening of event data was used to obtain realistic estimates for risk significant components. The changes made to the common cause analysis include:

- addition of common cause basic events to the fault trees including those for support system initiating events,
- development and application of special modified MGL models for asymmetrical configurations in the Emergency Diesel Generator (EDG) and Essential Service Water pump common cause groups,
- full re-quantification of MGL parameters using the INEEL database,
- plant specific screening of INEEL collected industry data for risk significant events,
- Bayesian update of MGL parameters to reflect plant specific experience, and
- development of uncertainty distributions for MGL model parameters.

The effort extended to the common cause failure parameters. The preferred source was INEEL-94/0064, "Common Cause Failure Data Collection and Analysis System," dated December 1995. This report deals with the derivation of common cause failure values and their application and represents the most comprehensive collection of common cause data ever developed. This INEEL report contained estimates of generic common cause factors that were used in the PRA update.

2.5.1 Emergency Diesel Generator Modeling

Additional detail was added to the EDG and AC power modeling in the linked fault tree model to support risk-based licensing requests. Each EDG is modeled for the following.

- Failure to start, including:
  - independent failure to start;
  - common cause failure to start;
  - unavailability due to maintenance at power;
  - unavailability due to maintenance during outage (other unit risk);
  - manual and auto start signals not generated; and
  - no DC power supply.

- Failure while running, including:

- independent failure to run;
- common cause failure to run;
- fuel oil makeup failure;
- room cooling failure; and
- jacket water heat exchanger cooling failure.

The treatment of mode dependent maintenance unavailability of the EDGs was needed to account for the ability to cross-tie the EDGs from Unit 2 to Unit 1, for the Unit 1 PRA model, and vice versa for the Unit 2 PRA model. The plant specific evaluation of PRA data parameters for the EDGs is summarized in Table E2-3. These are mean values of the evaluated uncertainty distributions that were developed using a Bayesian update procedure that synthesizes the evidence available from accepted generic industry data sources and plant specific operating experience at Byron and Braidwood Stations.

Table E2-3
Summary of EDG Reliability Data for Byron and Braidwood Stations

Data Parameter	Failure Mode/Type	Byron	Braidwood
Failure Rate	Fail to Start, per demand	1.89E-03	6.50E-03
	Fail to Run, per hr	6.33E-04	7.29E-04
Maintenance Unavailability	Unit at Power	3.91E-03	2.35E-03
	Unit Shutdown	5.92E-02	2.22E-02
Common Cause Parameters	Beta, Fail to Start	2.49E-02	2.59E-02
	Gamma, Fail to Start	5.39E-01	6.06E-01
	Delta, Fail to Start	1.0	1.0
	Beta, Fail to Run	3.64E-02	3.68E-02
	Gamma, Fail to Run	4.03E-01	5.21E-01
	Delta, Fail to Run	1.0	1.0

3.0 PRA Baseline Results for Core Damage Frequency (CDF)

The current baseline PRA results for each reactor unit at the Braidwood and Byron Stations are compared with the modified IPE results for each station in Table E3-1. The results of the upgraded PRAs show that the CDF of both stations is slightly higher than reported in the Modified IPEs and indicate only small differences across the four units. These changes are the result of many changes to the modeling of accident sequences, success criteria, quantification of common cause failures and human reliability, characterization of generic data, incorporation of plant specific data, and other model changes.

Table E3-1 Summary of Mean CDF Baseline PRA Results for Braidwood and Byron Station

Station	Reactor Unit	Modified IPE Result	Current PRA Update
Braidwood Station	Unit 1	2.80E-05	4.86E-05
	Unit 2		4.86E-05
Byron Station	Unit 1	4.05E-05	4.98E-05
	Unit 2		4.89E-05

Flooding was evaluated in the internal flooding analysis and flooding initiators are included in the Byron and Braidwood Stations PRAs. The EDGs are located in areas which are not vulnerable to flooding. However, while evaluating the baseline risk profile a significant risk contributor associated with Auxiliary Building flooding was identified. Auxiliary building flooding resulted in a loss of Essential Service Water to the charging pump, leading to a loss of injection to the RCP seals. ComEd will eliminate this vulnerability by a plant modification. The modification will provide alternate cooling to the charging pump lube oil cooler. The modification will be implemented prior to implementing the proposed changes once they are approved. The above risk evaluations include the assumption that the design modification will eliminate this risk contribution. At the completion of the modification, and prior to implementation of the proposed changes, an updated internal flooding evaluation will be performed to confirm that there is no impact on the conclusions of the current risk evaluation of the proposed extended Completion Times.

The contributions to CDF are similar for each of the four unit PRAs at the Braidwood and Byron Stations. As indicated in Figure E3-1 for Braidwood Station, Unit 1, the most important contributions from major initiating event classes arise from transients caused by support system faults. The importance of support system faults as initiating events has long been recognized and is very typical of PRAs of Pressurized Water Reactors (PWRs) that have been analyzed to a level of detail as has been performed here. Smaller contributions are due to front line system induced transients, and from LOCAs, with about equal contributions from LOCAs into the containment and containment bypass LOCAs. Secondary system pipe breaks and residual internal flooding events make only minor contributions.

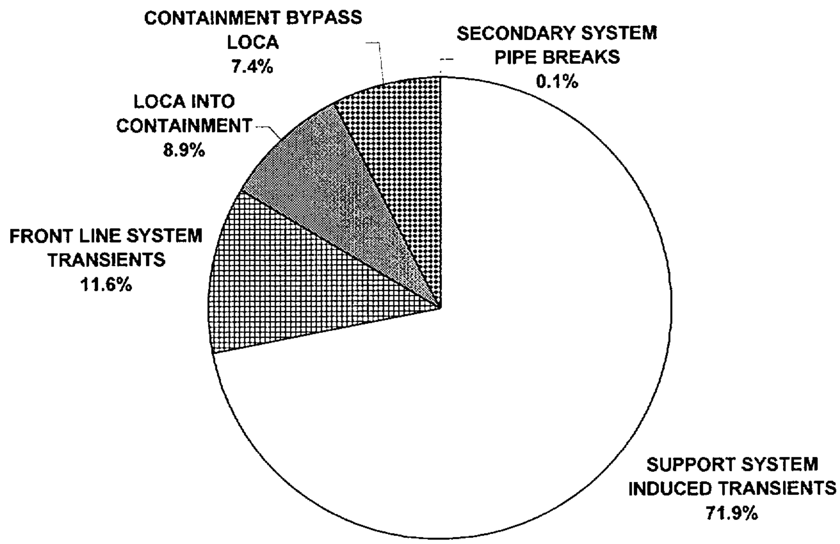


Figure E3-1 Contributions of Major Initiating Event Categories to Braidwood Station Unit 1 CDF

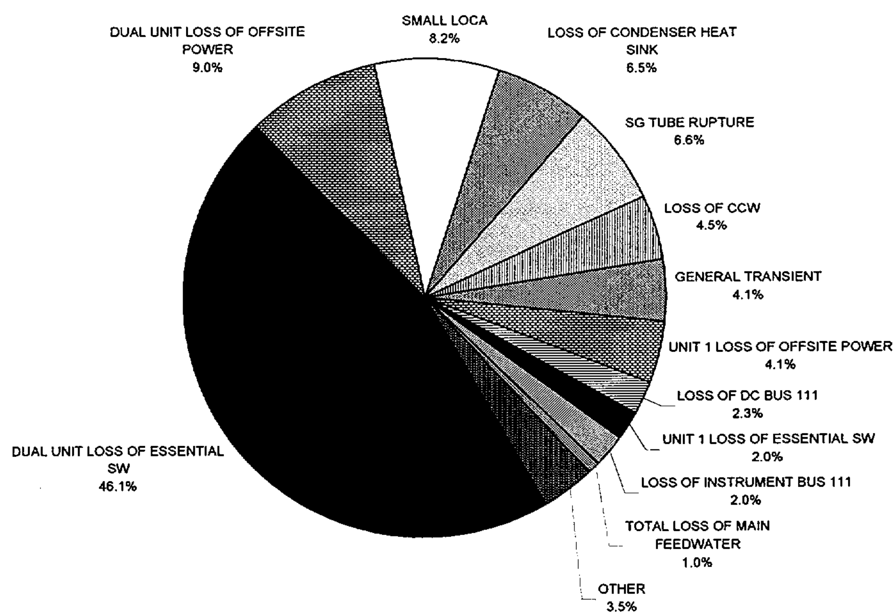


Figure E3-2 Contributions of Specific Initiating Events to Braidwood Station Unit 1 CDF

The contributions to CDF from specific initiating events at Braidwood Station, Unit 1 are depicted in Figure E3-2. As seen in this Figure a loss of Essential Service Water event that affects both units accounts for most of the support system initiator contribution and nearly half of the total CDF at Braidwood Station, Unit 1. LOOP events, which have been delineated to distinguish between events that impact both units concurrently and each unit singly, combine for about 13% of the total risk contribution. The most important contribution of initiating events that are not classified as support system initiating events are small LOCAs (8.2%), loss of condenser heat sink (6.5%) and SGTRs (6.6%). Loss of component cooling water and losses of individual DC and instrument AC buses also made visible contributions. Nearly 70% of the total CDF is associated with sequences involving a RCP seal LOCA.

It should be noted that the accident sequences and cutsets that could be impacted by the proposed increase in the EDG Completion Time are a small subset of the contributions from LOOP and DLOOP events. These initiating events contribute about 13% to the CDF, and only a small fraction of this contribution is due to scenarios involving EDG maintenance. Only the maintenance scenarios would be impacted by an increase in the EDG Completion Time.

Table E3-2 provides a tabulation of the CDF contribution by initiating event for Byron Station, Unit 1 and Braidwood Station, Unit 1 in the upgraded PRAs. This table shows that, while there are differences between the respective risk profiles, the general character of the profiles illustrated in Figures E3-1 and E3-2 is the same at both stations.

Table E3-2: CDF Contribution by Initiating Event

Initiating Event		Core Damage Frequency (Per Year)	
		Byron Station Unit 1	Braidwood Station Unit 1
1.	Excessive LOCA (i.e., Vessel Rupture)	2.66E-07	2.66E-07
2.	Large LOCA	1.58E-08	1.57E-08
3.	Medium LOCA	2.09E-08	2.07E-08
4.	Small LOCA		
	a. Non-isolable	4.03E-06	3.98E-06
	b. Isolable (Pressurizer PORV Fails Open)	2.88E-08	2.92E-08
5.	Interfacing Systems LOCA	4.05E-07	4.05E-07
6.	Steam Generator Tube Rupture (per SG)	8.34E-07	8.00E-07
7.	General Transient	4.09E-06	2.01E-06
8.	Loss of Condenser Heat Sink	3.28E-06	3.14E-06
9.	Total Loss of Feedwater – Recoverable	1.81E-07	6.15E-08
10.	Total Loss of Feedwater – Non-recoverable	8.65E-07	4.41E-07
11.	Steamline Break – Inside Containment (per SG)	9.59E-09	6.32E-09
12.	Steamline Break – Outside Containment	1.65E-08	1.53E-08
13.	Feedline Break - Inside Containment (per SG)	9.59E-09	6.32E-09
14.	Loss of Offsite Power (Single Unit) – Momentary	1.43E-07	4.49E-08
15.	Loss of Offsite Power (Single Unit) – Sustained	3.14E-06	1.97E-06
16.	Loss of Offsite Power (Dual Unit) – Momentary	6.05E-07	1.39E-07
17.	Loss of Offsite Power (Dual Unit) – Sustained	6.37E-06	4.38E-06
18.	Loss of One DC Bus		
	a. Loss of DC Bus 111	1.35E-06	1.13E-06
	b. Loss of DC Bus 112	1.43E-08	7.33E-09
19.	Loss of a 120V AC Instrument Bus		
	a. Loss of AC Bus 111	1.07E-06	9.70E-07
	b. Loss of AC Bus 112	3.25 E-09	2.15E-09
	c. Loss of AC Bus 113	3.25E-09	2.15E-09
	d. Loss of AC Bus 114	2.88 E-07	2.18E-07
20.	Loss of Non-Essential Service Water	1.78E-06	2.53E-07
21.	Loss of Instrument Air	6.79E-07	2.53E-07
22.	Loss of Component Cooling Water	9.34E-07	2.19E-06
23.	Single Unit Loss of Essential Service Water (Non-recoverable)	1.34E-06	9.94E-07
24.	Single Unit Loss of Essential Service Water (Recoverable)	2.84 E-09	< E-09
25.	Dual Unit Loss of Essential Service Water (Non-recoverable)	1.54E-05	2.24E-05
26.	Dual Unit Loss of Essential Service Water (Recoverable)	< E-09	< E-09
27.	Internal Flood Zones		
	a. Unit 1 Turbine Building, Grade Level (Zone 8.3-1)	< E-09	< E-09
	b. Unit 2 Turbine Building, Grade Level (Zone 8.3-2)	< E-09	< E-09
	c. Auxiliary Building, Elevation 426 (Zone 11.6-0)	< E-09	< E-09
Total		4.98E-05	4.86E-05

4.0 Evaluation of Large Early Release Frequency (LERF)

As part of the current Byron and Braidwood Station PRA, a simplified LERF analysis was performed in accordance with NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This analysis was used to evaluate the impacts of the proposed increase in EDG Completion Time on annual average LERF and to evaluate the Incremental Conditional Large Early Release Probability (ICLERP) for comparison against the risk significance criteria in RGs 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,"and 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." The LERF analysis for Byron and Braidwood Stations is comprised of the following elements:

- plant damage states that define the Level 1/Level 2 interface,
- a standardized containment event tree for Westinghouse 4-loop PWRs for large dry containment,
- plant specific accident sequence models from the Level 1 PRA to estimate the frequencies of major accident classes that challenge the containment integrity,
- default and conservative containment event tree split fractions from NUREG/CR-6595 to account for the influences of severe accident phenomena that challenge the containment functions to protect against large early releases, and
- Separate integrated linked fault tree model to evaluate LERF for each reactor unit at the Byron and Braidwood Stations. These models integrate the Level 1 accident sequence models that characterize challenges to containment integrity, the containment event trees and the Level 1/Level 2 interface in a manner that captures important dependencies and plant specific features that are important for LERF.

This approach captures the plant specific factors associated with active systems whose failures contribute to LERF such as containment isolation and bypass, and the frequency of severe accident challenges of the containment. These aspects of the LERF analysis are as realistic as the Level 1 PSA for CDF determination. There are other aspects of this simplified approach that provide a rather conservative treatment of the phenomenological issues that contribute to LERF such as high pressure melt ejection, direct containment heating, and thermal creep rupture of Reactor Coolant System (RCS) components and the Steam Generator tubes. These conservatisms include a very conservative definition for high pressure core melt sequences and conservative split fractions for modeling the impact of severe accident challenges to containment performance. Hence, these LERF results should be regarded as conservative estimates in relation to the CDF results.

The results of the LERF quantification for each unit at Byron and Braidwood Stations are shown in Table E4-1 and Figure E4-1.

Table E4-1 LERF Results for Byron and Braidwood Stations

LERF Contribution	Byron Station		Braidwood Station	
	Unit 1	Unit 2	Unit 1	Unit 2
Unisolated SG Tube Ruptures	3.33E-06	3.23E-06	3.12E-06	3.12E-06
Containment Over-pressurization	1.22E-06	1.26E-06	9.42E-07	9.42E-07
Containment Isolation Failures	5.55E-07	5.47E-07	4.46E-07	4.46E-07
Interfacing Systems LOCAs	3.89E-07	3.83E-07	3.97E-07	3.97E-07
Induced SG Tube Ruptures	5.55E-08	5.47E-08	4.96E-08	4.96E-08
Total Large Early Release Frequency (LERF)	5.55E-06	5.47E-06	4.96E-06	4.96E-06
LERF as a % of CDF	11.4%	11.0%	10.0%	10.1%

These results are all within the criteria for risk significance in Section 2.2.4 of RG 1.174 and are consistent with results from other PWRs with large, dry containments that generally range from 3% to 15% of CDF. In reviewing these results, the following conservative aspects of the LERF evaluation should be kept in mind.

- The current LERF evaluation of SGTR sequences conservatively neglects long term actions to isolate the faulted SG. If there is a failure to initially isolate the SG and failure to control RCS pressure, there are no subsequent recovery actions credited to isolate the SG after the onset of core damage. In addition there is no credit taken for scrubbing of fission products that would be expected for SGTR sequences in which there is over-filling of the secondary side of the SGs.
- There is only limited credit in the current LERF evaluation for procedure guided actions to depressurize the RCS after the time of core uncovery and before vessel breach. Such credit is limited to selected sequences involving dual unit loss of Essential Service Water and transient sequences involving failure to open the Pressurizer Power Operated Relief Valves (PORVs) for bleed and feed. All sequences in the LERF model would be subject to procedure driven actions to depressurize the RCS that are backed up by Severe Accident Management Guidelines. Hence the current LERF analysis overstates the likelihood of high pressure core melt sequences.

- While an accepted methodology for assignment of Level 1 plant damage state bins was utilized to support the interface with the LERF model, the definition of plant conditions in the Level 1 event tree logic was in some cases insufficient to determine the RCS pressure state at the time of vessel breach. This uncertainty was addressed by additional conservative assumptions that tend to increase the calculated LERF values.
- Application of the NUREG/CR-6595 methodology has provided a very conservative evaluation of containment failure from severe accident phenomena though the use of default split fractions for containment failure at the time of vessel breach due to severe accident phenomena. Containment failure probabilities of 0.1 for high pressure core melts and 0.01 for low-pressure core melts is specified in this simplified methodology. Moreover, the breakpoint between high and low pressure is set at the conservative value of 200 psia. It is expected that a realistic treatment of these phenomena and consideration of the plant specific containment structural capacity would yield LERF contributions from severe accident loads that are one to two orders of magnitude below those calculated here.
- Induced SGTRs was treated with a conservative split fraction of 0.018 for all high-pressure melt sequences with no SG cooling, without consideration of induced RCS hot leg rupture. This is generally regarded in the severe accident analysis community as much more likely than induced SGTR and if occurred would terminate the heat up of the SG tubes.

It is expected that if a more realistic treatment of the above issues were performed, the above estimates of LERF would be significantly reduced. However, this LERF analysis is sufficient to support evaluation of the risk significance of the requested increase in the EDG completion time, as many of the conservative assumptions, while affecting the baseline LERF values, do not impact the change in risk metrics associated with the requested increased Completion Time.

The relative contribution to LERF from the various containment failure modes/bypasses is illustrated in Figure E4-1. Depending on the unit, 76% to 80% of the LERF arises from contributions of a systemic nature and are essentially a byproduct of the Level 1 PRA. These include containment bypass due to unisolated SGTRs and ISLOCAs, and failure to isolate large containment penetrations that could contribute to a large and early release. Only 20% to 24% of the LERF is due to severe accident phenomena such as containment over-pressurization from direct containment heating, reactor vessel steam explosions, or induced tube ruptures in the steam generators. As noted above, this contribution to LERF is viewed as highly conservative and driven by conservative assumptions in the NUREG/CR-6595 methodology in the treatment of severe accident phenomena.

SGTR initiating events are the largest contributors (59% to 63%) to LERF at each reactor unit. ISLOCAs contribute 7% to 8%. Induced SGTRs contribute only about 1% of the LERF.

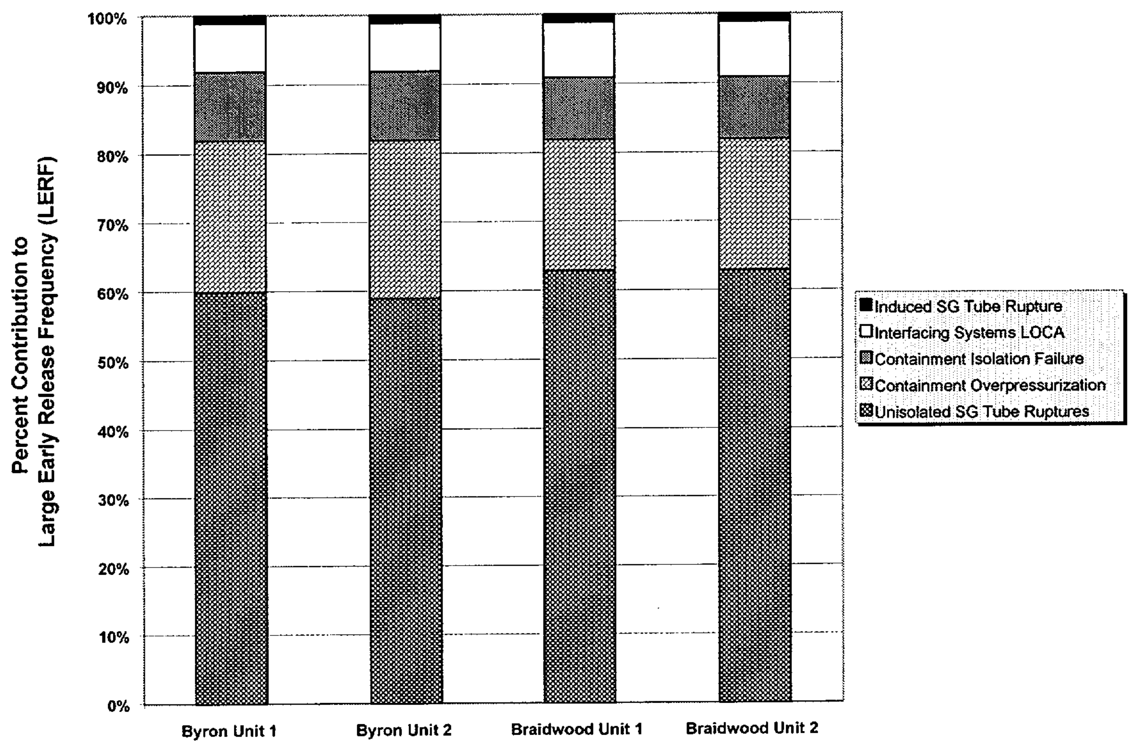


Figure E4-1 Contributions of Major Accident Classes to LERF at Byron and Braidwood Stations

The containment failure at vessel breach (high pressure) contributes 19% to 23% to LERF. This result is based on a very conservative criterion for defining high pressure challenges to the containment (i.e., > 200 psia) and a very conservative containment failure probability from high and low pressure challenges (i.e., 0.1 and 0.01, respectively). Also, plant-specific analysis of the type performed in the original IPE would show that these containment failure probabilities are very conservative. Nonetheless, this part of the LERF profile, if eliminated, would only cause a 19% to 23% decrease in LERF, and hence, the need to perform a more detailed and realistic assessment of severe accident phenomena is questionable for most envisioned applications of this PSA unless an updated assessment of the systemic contributions results in an increase in the relative importance of these contributors.

The conservatisms in the characterization of severe accident challenges in this simplified LERF analysis will tend to overstate the impact of the increased EDG Completion Times on LERF. The impact tends to be overstated because the SBO sequences that are influenced by increases in EDG maintenance unavailability include high-pressure core melt sequences such as those with no RCS cooldown and depressurization. These SBO sequences in turn contribute to the containment over-pressurization scenarios that are affected by these conservatisms. Hence, a more realistic LERF evaluation would predict reduced impacts on LERF in comparison with those presented in Attachment A. However, the results of the LERF evaluation presented in Attachment A show that decision criteria for determining risk significance of the increase EDG Completion Time are still satisfied despite the conservatisms noted.

Containment isolation failures contribute 9% to 10% to LERF. Some of these sequences involve contributions from EDG maintenance unavailability and hence can be influenced by the increased Completion Times of the EDGs to the extent that these maintenance unavailabilities are influenced by an increased Completion Time.

In summary, the LERF results for Byron and Braidwood Stations are considered reasonable and exhibit some conservatisms in the treatment of severe accident phenomena and in the omission of many operator actions and accident management strategies that would be expected to reduce the LERF contribution but were omitted from this LERF evaluation. The major LERF accident classes that could be influenced by changes in EDG maintenance unavailability are those associated with containment over-pressurization during high pressure melt sequences, and sequences involving containment isolation failures. All remaining LERF contributions are not influenced by changes in EDG maintenance unavailability.