April 14, 2006

Mr. J. V. Parrish
Chief Executive Officer
Energy Northwest
P.O. Box 968 (Mail Drop 1023)
Richland, WA 99352-0968

SUBJECT: COLUMBIA GENERATING STATION - ISSUANCE OF AMENDMENT RE: EXTENSION OF DIESEL GENERATOR COMPLETION TIME (TAC NO. MC3203)

Dear Mr. Parrish:

The U.S. Nuclear Regulatory Commission (Commission) has issued the enclosed Amendment No.197 to Facility Operating License No. NPF-21 for the Columbia Generating Station. The amendment consists of changes to the Technical Specifications (TS) in response to your application dated May 19, 2004, as supplemented by letters dated September 1, 2005, January 9, February 23, and March 20, 2006, and e-mails dated March 13 and 30, 2006.

The amendment extends the Required Action Completion Times (CT) specified in TS 3.8.1, "AC Sources - Operating," to restore an inoperable DG to operable status from the current 72 hours to 14 days.

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Brian J. Benney, Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-397

Enclosures:
1. Amendment No. 197 to NPF-21
2. Safety Evaluation

cc w/encls: See next page

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DATE	4/14/06	4/14/06	4/14/06	4/14/06

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ENERGY NORTHWEST

DOCKET NO. 50-397

COLUMBIA GENERATING STATION

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 197
License No. NPF-21

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Energy Northwest (licensee) dated May 19, 2004, as supplemented by letters dated September 1, 2005, January 9, February 23, and March 20, 2006, and e-mails dated March 13 and 30, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-21 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 197 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

David Terao, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: April 14, 2006

ATTACHMENT TO LICENSE AMENDMENT NO. 197

FACILITY OPERATING LICENSE NO. NPF-21

DOCKET NO. 50-397

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain vertical lines indicating the areas of change. The corresponding overleaf pages are also provided to maintain document completeness.

REMOVE	INSERT
3.8.1-2	3.8.1-2
3.8.1-3	3.8.1-3
3.8.1-4	3.8.1-4
3.8.1-5	3.8.1-5

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 197 TO FACILITY OPERATING LICENSE NO. NPF-21

ENERGY NORTHWEST

COLUMBIA GENERATING STATION

DOCKET NO. 50-397

1.0 INTRODUCTION

By application dated May 19, 2004, as supplemented by letters dated September 1, 2005, January 9, February 23, and March 20, 2006, and e-mails dated March 13 and 30, 2006 (Agencywide Documents Access and Management System Accession Nos. ML041540545, ML052560269, ML060180459, ML060680239, ML060880420, ML060950067, and ML061020271 respectively), Energy Northwest (licensee) requested a risk-informed license amendment to revise the Columbia Generating Station (CGS) Technical Specifications (TSs) (Appendix A to Facility Operating License No. NPF-21) related to Division 1 and Division 2 diesel generators (DGs) Limiting Conditions for Operations (LCOs). The requested change would extend the Required Action Completion Times (CTs) specified in TS 3.8.1, "AC [Alternating Current] Sources - Operating," to restore an inoperable DG to operable status from the current 72 hours to 14 days. The supplemental letters provided additional information that clarified the application, but did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination.

The purpose of the proposed change is to provide the licensee with needed flexibility in performing both corrective and preventive maintenance during power operation on Division 1 and Division 2 DGs. On November 4, 2004, the Nuclear Regulatory Commission (NRC) staff forwarded a request for additional information (RAI) to the licensee. The licensee responded to the RAI by letter dated September 1, 2005.

On December 8, 2005, the licensee met with the NRC staff to discuss the amendment request. At that time, the NRC staff requested that certain issues be clarified on the docket. Subsequently, in a letter dated January 9, 2006, supplemented by letters dated February 23 and March 20, 2006, the licensee provided clarification on the issues discussed in the meeting.

The proposed CT extension is based on the findings of both deterministic and probabilistic risk assessment (PRA) perspectives. The NRC staff has reviewed the proposed change to LCO 3.8.1 and finds it acceptable, as discussed in the following evaluation.

1.1 Proposed License Amendment

The licensee proposed to revise the CT specified for restoration of an inoperable Division 1 DG (DG-1) or Division 2 DG (DG-2) from 72 hours to 14 days. TS LCO 3.8.1, "AC Sources - Operating," specifies requirements for the electrical power system AC sources. For CGS, the electrical power system AC sources consist of the offsite power sources and the Class 1E onsite standby power source diesel generators DG-1, DG-2, and DG-3 for the high-pressure core spray (HPCS) system.

As part of the amendment request, the licensee has developed plant modifications to add a mobile, 480 volt (V), DG designated as DG-4, with associated connections to permanent plant wiring and hardware to allow connection to the plants Class 1E bus and associated division battery chargers. Further, the licensee is modifying Division 3 to allow cross connection and alignment of DG-3 to Division 1 or Division 2 emergency buses (but not both simultaneously).

The addition of DG-4 provides supplemental AC power to the Division 1 250V and 125V battery chargers and the Division 2 125V battery charger. Though the addition of DG-4 extends battery life during a station blackout (SBO), this is a risk management action and is not credited as additional SBO coping equipment in the licensee's SBO analysis. The cross-connect capability from DG-3 allows power to be supplied to either Division 1 or Division 2 selected safe shutdown loads with the loss of power to Division 1 or 2 or during an SBO. The cross connecting of DG-3 provides an additional power source to low pressure systems and is also added as a risk management measure, but not credited in the licensee's SBO analysis. The licensee evaluated the impact on plant risk from adding DG-4 and provided risk insights for the added cross-tie capability for DG-3. Both of these modifications provide a risk benefit, but only the addition of DG-4 is credited in the licensee's PRA analysis. The licensee stated that the proposed DG CT extension results in a small increase in risk, consistent with Regulatory Guides (RGs) 1.174 and 1.177, without crediting DG-3 or DG-4. The addition of DG-4, compensatory measures, and the addition of the DG-3 cross connect provides an improvement or offset to the proposed extended DG-1 and DG-2 CT. The addition of DG-4 and the proposed extended CT may be considered a Category 1 combined change request per the guidance of RG 1.174. For a Category 1 combined change request (CCR) the contribution of each individual change in the CCR must be quantified in the risk assessment and the uncertainty of each change addressed. In addition, the changes that make up the CCR should be related to each other or of the same type. The licensee's requests are related since DG-4 and the additional cross-tie from DG-3 can be aligned to the same loads as DG-1 and DG-2. The licensee provided risk assessments for both the addition of DG-4 and the DG-3 cross-connect, and the total risk impact of these changes taken together.

Although the licensee stated that the current CT for the restoration of an inoperable DG is sufficient to support current surveillance testing, limited online maintenance, and post maintenance testing activities, the requested changes are sought to provide additional flexibility and more efficient planning in the performance of selected corrective maintenance (CM) and preventive maintenance (PM) activities during power operations. Specifically, the approval of the proposed change will allow the following:

- Provide additional flexibility in the scheduling and performance of PM.

- Improve control of resource allocation by allowing online PM, including scheduled overhauls. The change provides the flexibility to focus more resources on any required or elective DG maintenance.

- Limits unplanned plant shutdowns and minimizes the potential for requests for notices of enforcement discretion.

- Improve DG availability during shutdown modes or conditions.

- Reduce the number of individual entries in required actions statements by providing sufficient time to perform related maintenance tasks with a single entry.

The licensee's proposal also includes new regulatory commitments. The licensee proposed 18 specific regulatory commitments, which are presented in Section 4.0 of this safety evaluation (SE).

1.2 Related Nuclear Regulatory Commission Activities

This license amendment is not related to or in response to any on-going NRC activities (e.g., generic letters).

1.3 Description of Structures/Systems/Components

This section identifies the structures, systems, and components (SSCs) related to the proposed licensee amendment and their associated regulatory requirements.

As stated by the licensee, the Class 1E AC distribution system supplies electrical power to three divisional load groups, Divisions 1, 2, and 3, with each division powered by an independent Class 1E 4.16kV engineered safety features (ESF) bus. The Division 1 and Division 2, 4.16kV ESF buses have two separate and independent offsite sources of power. The Division 3, 4.16kV ESF bus has one source of offsite power. Each Class 1E 4.16kV ESF bus has a dedicated onsite DG. Any two of the three divisions of ESF systems provide the minimum safety functions necessary to achieve and maintain plant shutdown and mitigate the consequences of a design-basis accident (DBA).

CGS's Final Safety Analysis Report (FSAR), Chapter 8, describes the offsite power network supply to the transformer yard from the Bonneville Power Administration (BPA) transmission network. From the transformer yard, two qualified, electrically and physically separated circuits provide AC power to the Division 1 and Division 2, 4.16kV ESF buses (SM-7 and SM-8). One qualified circuit provides AC power to the Division 3, 4.16kV ESF bus (SM-4). One qualified circuit is powered from the 230kV Ashe Substation stepped down through the 230kV/4.16kV windings of a 230kV/6.9kV/4.16kV transformer (the startup transformer, TR-S) through connecting switchgear to all 4.16kV ESF buses. The other qualified circuit (to Division 1 and Division 2, 4.16kV ESF buses only) is powered from the 115kV Benton Substation stepped down through a 115kV/4.16kV transformer (the backup transformer, TR-B). The offsite AC electrical power sources are designed and located to minimize, to the extent practicable, the likelihood of their simultaneous failure under anticipated operational occurrences and in the event of postulated accidents.

A qualified offsite circuit consists of breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF buses. The startup transformer normally provides power to the 4.16kV ESF buses when the main generator is not connected to the grid. An automatic transfer feature is provided for the ESF divisions. If power is lost to the Division 1 and Division 2, 4.16kV ESF buses (SM-7 and SM-8) due to a loss of the startup transformer supply, the backup transformer (TR-B) supply breaker to the bus will automatically close and provide power. When the main generator is supplying power to the grid, the connection is to the 500kV grid. In this normal operational line up, power is provided to all the 4.16kV ESF buses by a 25kV/4.16kV normal auxiliary transformer (TR-N1) fed from the main generator 25kV isolated phase bus. However, this power source is not credited with meeting the requirements of LCO 3.8.1.a, because it does not come from an offsite circuit

Automatic transfer capability is provided so that failure of the TR-N1 supply causes immediate tripping of the normal auxiliary transformer supply breakers and simultaneous closing of the TR-S auxiliary switchgear breakers to supply the balance of plant and ESF buses. Each TR-S supply breaker is interlocked to close only if the associated normal auxiliary transformer supply breaker is not locked out, thus preventing closing onto a fault or connecting a credited source to a non-credited source. Manual live transfer capability of power between the normal auxiliary transformer source and the startup and backup (Division 1 and Division 2 only) transformer sources is also provided.

The CGS FSAR states that each Division 1 and 2 standby power sources have sufficient capacity to provide power to all its required divisional loads. The standby electrical system consists of 4.16V Division 1 or 2 switchgear buses and associated DGs, 480 volts alternating current (VAC) auxiliary distribution systems, 120/208 VAC, and 125 and 250 volts direct current (VDC) power and control systems. In the event of loss of the normal and offsite power sources (as detected by 4.1kV Class 1E bus undervoltage) or receipt of a loss-of-coolant accident (LOCA) signal, these standby sources are designed to start and, if an undervoltage condition exists, connect automatically. This is accomplished in sufficient time to maintain the reactor in a safe condition, safely shut down the reactor, or limit the consequences of a DBA to acceptable limits.

The Division 3 HPCS standby power source is designed to supply all power required for emergency core cooling (i.e., water spray) in the event of a LOCA. This system consists of the 4.16kV HPCS switchgear bus, HPCS pump motor and DG-3, and the associated 480V HPCS auxiliary distribution system supplying motor operated valves, engine cooling water pumps, and miscellaneous engine auxiliary loads. With offsite power unavailable, DG-3 can furnish onsite power in sufficient time to provide all power for startup and operation of the HPCS pump motor for accident mitigation. DG-3 starts automatically on receipt of a 4.16kV HPCS bus undervoltage or LOCA signal. With a HPCS bus undervoltage condition, DG-3 is also connected to the bus automatically.

The system is self-contained, except for access to the normal and offsite power sources (connected through plant AC power distribution) and for instrumentation connection to the LOCA start signal. Isolated operation, independent of electrical connections to other power sources, is accomplished by direct connection to the 4.16kV HPCS DG. Currently, there is no sharing of the HPCS power system, but the proposed amendment has been revised through the licensee's RAI response to provide a cross-connect capability such that DG-3 can be connected to the Division 1 or 2 bus.

The licensee is also adding a permanent alternate AC source to the battery chargers designated as DG-4. DG-4 is a trailer mounted 480V DG that, through additional permanent internal plant wiring and hardware, connects to the Class 1E bus to supply the division's battery chargers. DG-4 is considered available once staged and verification testing is completed.

2.0 REGULATORY EVALUATION

General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR) requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of SSCs that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of a loss of power from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and testing of electric power systems," requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing.

Section 50.63 of 10 CFR, "Loss of all alternating current power," requires that all nuclear power plants must have the capability to withstand a loss of all AC power for an established period of time. This is further addressed by RG 1.155, "Station Blackout."

The Maintenance Rule, Section 50.65 of 10 CFR, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that the licensee shall monitor the performance or condition of SSCs against licensee-established goals, in a manner sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions as applicable to the Implementing and Monitoring Program guidance of RG 1.174, Section 2.3 and RG 1.177, Section 3. In addition, 10 CFR 50.65(a)(4), as it relates to the proposed CT extension, requires the assessment and management of the increase in risk that may result from the proposed maintenance activity.

Section 50.90 of 10 CFR, "Application for amendment of license or construction permit," addresses the requirement for a licensee seeking to amend their license, which includes the TSs.

The regulatory requirements related to the contents of TSs are set forth in Section 50.36(c)(2) of 10 CFR, "Technical specifications," which requires a licensee's TS to establish LCOs. This requirement includes SSCs that are required for safe operation of the facility, such as the CGS DGs.

RG 1.93, "Availability of Electric Power Sources," provides guidance with respect to operating restrictions (i.e., CTs) if the number of available AC sources is less than that required by the TS LCO. In particular, this guidance prescribes a maximum CT of 72 hours for an inoperable onsite or offsite AC source.

General guidance for evaluating the technical basis for proposed risk-informed changes is provided in Chapter 19.0, "Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance," of the NRC Standard Review Plan (SRP), NUREG-0800. More specific guidance related to risk-informed TS changes is provided in SRP Section 16.1, "Risk-Informed Decisionmaking: Technical Specifications," which includes CT changes as part of risk-informed decisionmaking. Chapter 19.0 of the SRP states that a risk-informed application should be evaluated to ensure that the proposed changes meet the following key principles:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change.
- The proposed change is consistent with the defense-in-depth philosophy.
- The proposed change maintains sufficient safety margins.
- When proposed changes result in an increase in core damage frequency (CDF) or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (51 FR 30028 August 4, 1986).
- The impact of the proposed change should be monitored using performance measurement strategies.

RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Graded Quality Assurance," identifies an acceptable risk-informed approach including additional guidance specifically geared toward the assessment of proposed TS CT changes. Specifically, RG 1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed CT TS change as identified below.

- Tier 1 assesses the risk impact of the proposed change in accordance with acceptance guidelines consistent with the Commission's Safety Goal Policy Statement, as documented in RG 1.174 and RG 1.177. The first tier assesses the impact on operational plant risk based on the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF). It also evaluates plant risk while equipment covered by the proposed AOT is out-of-service, as represented by incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). Tier 1 also addresses PRA quality, including the technical adequacy of the licensee's plant-specific PRA for the subject application. Cumulative risk of the present TS change in light of past applications or additional applications under review are also considered along with uncertainty/sensitivity analysis with respect to the assumptions related to the proposed TS change.

- Tier two identifies and evaluates any potential risk-significant plant equipment outage configurations that could result if equipment, in addition to that associated with the proposed license amendment, is taken out of service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The purpose of this evaluation is to ensure that there are appropriate restrictions in place such that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed CT is implemented.

- Tier three addresses the licensee's overall configuration risk management program (CAMP) to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and appropriate compensatory measures to avoid such configurations are taken that may not have been considered when the Tier 2 guidance was developed. Compared with Tier 2, Tier 3 provides additional coverage to ensure risk-significant plant equipment outage configurations are identified in a timely manner and that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity over extended periods of plant operation. Tier 3 guidance can be satisfied by the Maintenance Rule (10 CFR 50.65(a)(4)), which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance, testing, CM, and PM, subject to the guidance provided in RG 1.177 section 2.3.7.1 and the adequacy of the licensee's program and PRA model for this application. The CRMP is to ensure that equipment removed from service prior to or during the proposed extended CT will be appropriately assessed from a risk perspective.

More specific methods and guidelines acceptable to the staff are also outlined in RG 1.177 for assessing risk-informed TS changes. Specifically, RG 1.177 provides recommendations for utilizing risk information to evaluate changes to TS CTs and surveillance test intervals with respect to the impact of the proposed change on the risk associated with plant operation. RG 1.177 also describes acceptable implementation strategies and performance monitoring plans to help ensure that the assumptions and analysis used to support the proposed TS changes will remain valid.

3.0 TECHNICAL EVALUATION

3.1 Detailed Description of the Proposed Change

Currently, CGS TS 3.8.1 Action B.4 requires restoration of an inoperable DG to operable status within 72 hours. The licensee proposes revised wording be added that will allow the inoperable DG to be restored to an operable status within the proposed extended 14-day CT for a single inoperable DG (DG-1 or DG-2) when risk management actions have been implemented. The licensee proposes to revise TS 3.8.1, "AC Sources - Operating" as follows:

1. Add a new optional set of required actions to B.4:

"B.4.2.1 Establish risk management actions for the alternate AC sources."

AND

B.4.2.2 Restore required DG to OPERABLE status.

The CT for Action B.4.2.1 is established at 72 hours.

The CT for Action B.4.2.2 is revised to 14 days AND 17 days from the discovery of failure to meet the LCO.

2. The CT for Action B.3.2 is revised to add, "if not performed in the past 24 hours."

3. Action B.4 is renumbered to B.4.1

4. Action B.4.1 CT of 72 hours is revised to include, "from discovery of an inoperable DG."

5. The CT for Action A.3 is revised to read: "6 days from the discovery of failure to meet the LCO" to "6 days from the discovery of failure to meet LCO when not associated with Required Action B.4.2.2."

6. The CT for Action A.3 is revised to add "17 days from the discovery of failure to meet the LCO."

The licensee stated that the use of the extended CT for voluntary planned maintenance or inspections should be limited to once within an operating cycle for each DG, consistent with the licensee's PRA assumptions.

3.2 Deterministic Evaluation

The traditional engineering evaluation presented below addresses the first three key principles of the NRC staff's philosophy of risk-informed decision making, concerning compliance with current regulations, evaluation of defense-in-depth, and evaluation of safety margins.

As a defense-in-depth measure, during the extended outages of the DG-1 and DG-2, the licensee installed an additional AC power source, designated as DG-4, to the battery chargers. DG-4 is a mobile, 480 volt DG with its associated cabling, which can be connected to the Class 1E bus that supplies a division's battery chargers and prevents further discharge of the batteries during an SBO. The CT for the Required Action to establish DG-4 was chosen to correspond with the existing 72-hour CT for Required Action B.4.1. For planned DG maintenance, this feature will be established prior to entry. For emergent conditions requiring DG maintenance, this Required Action would be established prior to exceeding the 72-hour CT of Required Action B.4.2.1.

Originally, the licensee requested the CT extension primarily based on the installation of the DG-4. In its letter dated November 4, 2005, as well as in the number of conference calls with the licensee, the NRC staff informed the licensee that in light of the recent experiences with grid losses, the availability of an alternate AC power source is needed for approval of an extended

DG allowed CT. In response to the NRC staff position, the licensee has proposed to use Division 3 DG (DG-3 for the HPCS pump) as the alternate source of power to either Division 1 or Division 2 AC buses via a cross-connect when one DG is in the extended outage during a loss of offsite power (LOOP) event.

The licensee completed the installation of a cross-connection feature to allow DG-3 to power the Division 1 or Division 2, ESF bus at CGS. The licensee stated that cross-connection is a permanent plant feature using electrical breakers that are part of the original design. These spare breakers will be available to accomplish the cross-connection in the three non-safety related switchgear cabinets that supply Division 1, 2, and 3 ESF buses. In this alignment, the function of the DG-3 is to supply selected safe shutdown systems in one division and the HPCS pump will be secured. The licensee indicated that there are no automatic connections from the DG-3 to either Division 1 or 2 by this design change. In performing this cross-connection, administrative and design features are used to assure that adequate independence and separation are maintained and any deleterious interaction is avoided. The LOOP and SBO response and alignment procedures will detail the cross-connection actions that selectively strip one of the de-energized buses (Division 1 or Division 2) of its loads, defeats the HPCS LOCA automatic initiation signals, and performs breaker line-ups from DG-3 to power the selected ESF emergency switchgear. The licensee indicated that the cross-connection can be accomplished within 2 hours. When the cross-connection procedures are finalized, this ability will be verified through training and simulation to assure adequate on-shift resources can respond and accomplish the alignment within the 2 hours.

The licensee stated that the decision to energize the cross-connect will be based upon Shift Manager action according to the SBO procedure, which should ensure that these additional features are properly coordinated with the NRC staff approved Section 50.63 of 10 CFR SE and CGS's SBO coping strategy. Further, the following criteria need to be met before the cross-connection can be made:

- No known fault exists which could damage DG-3, and
- DG-3 and bus are available, and
- Energization of Division 1 or Division 2 is required for safe shutdown or to maintain adequate core cooling, and
- The Shift Manager has authorized energization of the cross-connection to assure other plant conditions are taken into account.

The NRC staff noted that in the SBO analysis, DG-3 is used to power the HPCS pump and its associated systems which are relied upon as an injection source to the reactor vessel during an SBO. However, the licensee stated in its letter dated May 7, 1991, that both Reactor Core Isolation Cooling (RCIC) and HPCS pumps will be available to maintain the reactor coolant system (RCS) inventory, but preferring RCIC to maintain reactor pressure vessel (RPV) level.

In the NRC SE, dated December 30, 1991, the NRC staff stated that if the licensee plans to use the RCIC system for level control, the licensee needs to analyze the effect of the RCIC system on each part of the coping calculation and include the revised coping analysis with the documentation that is to be retained by the licensee in support of the SBO submittal. The licensee provided additional information to the NRC on SBO related issues, including the RCIC, in letters dated March 6 (G02-92-057), April 15 (G02-92-099), and May 14, 1992 (G02-92-121). Based on the information provided in the forgoing letters, the licensee stated the following (documented in Supplemental SE, dated June 26, 1992) with respect to the use of RCIC for coping with an SBO.

> The coping analysis completed for WNP-2 considered the separate and combined operation of HPCS and RCIC on the considerations for battery capacity, compressed air, containment isolation and loss of ventilation. The combined operation of RCIC and HPCS may result in more rapid transfer of water from the condensate storage tanks to suppression pool, but it will not change the inventory required for an SBO or the amount of condensate available.
>
> Although not required by our response, heat up of the RCIC room was evaluated using the methodology of NUMARC 87-00. The 4 hour temperature is 133 °F with the doors closed. For the type of equipment located in the RCIC pump room, the maximum temperature of 133 °F provides reasonable assurance of operability of the SBO equipment located in this room.

In the NRC SE dated June 26, 1992, the NRC staff concluded, based on the CGS licensee's statements, that there was reasonable assurance of operability of the SBO equipment located in the RCIC pump room, and its use for maintaining RPV level. Therefore, the NRC staff had no objection to the sole or combined use of the RCIC for SBO mitigation with the understanding that the HPCS pump was available to maintain the RCS inventory.

The NRC staff informed the licensee that the HPCS DG could be used to meet the alternate AC power source requirements provided that the HPCS is not relied upon to power the HPCS pump for SBO mitigation. The NRC staff was concerned that since the HPCS DG is relied upon as the credited power source for the HPCS pump and its associated systems for SBO mitigation, the HPCS DG could not be used as an alternate AC power source in the event of a LOOP when either DG-1 or DG-2 are taken out for extended maintenance outage.

On December 8, 2005, the licensee met with the NRC staff to discuss the use of RCIC system in the SBO analysis and DG-3 as an alternate AC power source. The licensee provided background information on CGS's onsite and offsite power distribution, and how its proposal is an improvement to safety. In response to the NRC staff's concerns, the licensee discussed how the cross connect would be used in various scenarios. The NRC staff requested a description of the DG-3 cross-connect implementation plan that would be controlled by procedure and for clarification on when DG-3 would be used as an alternate AC power source during online DG maintenance when HPCS is also a credited system for coping with an SBO.

In a letter dated January 9, 2006, supplemented by letter dated February 23, 2006, the licensee provided information that clarified the licensing basis issue. The licensee stated that although the credited operating system for meeting Section 50.63 of 10 CFR is HPCS, the RCIC is the preferred coping equipment for high-pressure injection. The licensee indicated that SBO procedures direct operators to use RCIC first. Upon the onset of the LOOP with concurrent main turbine trip, the division associated with the DG out-of-service for maintenance would not have power and would need to be aligned to be ready to receive power from DG-3. In the event that the LOOP progressed to an SBO condition because the remaining Division 1 or 2 DG failed, RCIC would be the preferred coping equipment for high-pressure injection.

Additionally, the licensee stated that during entry into the extended DG CT, procedures for implementing the cross-connect will provide for the cross-connection to be accomplished within 2 hours of the occurrence of a LOOP or an SBO. The cross-connection will be accomplished in two stages. Upon the onset of the LOOP or an SBO, the division associated with the DG out-of-service for maintenance will be configured to be ready to receive power from DG-3. This stage aligns DG-3 to power the properly configured Division 1 or 2 bus and involves the steps that shift DG-3 from powering the HPCS high-pressure function to being able to power the low-pressure ECCS or heat removal function. This stage should be able to be accomplished in less than 30 minutes. During entry into the extended DG CT, the licensee indicated that procedures will be written to direct full implementation of the cross-connect within 2 hours of a LOOP or an SBO unless plant conditions dictate otherwise. The licensee provided the following additional regulatory commitment:

> Establish procedures that during entry into the extended DG CT to direct full implementation of the DG-3 cross-connect to Division 1 or Division 2 switchgear (SM-7 or SM-8) within two hours of a LOOP or SBO unless plant conditions dictate otherwise.

The licensee also stated that an action has been established within its corrective action program to review existing docketed correspondence and internal evaluations associated with Section 50.63 of 10 CFR SBO analysis and provide additional clarification to the NRC concerning RCIC's role in SBO mitigation.

On February 14, 2006, during a conference call with the licensee the NRC staff requested clarification on the intent of the words "unless plant conditions dictate otherwise" in the above commitment.

In a letter dated February 23, 2006, the licensee stated that the words "unless plant conditions dictate otherwise" are intended to refer to unexpected failures that either (1) cause HPCS to be needed to provide adequate core cooling, such as failure of RCIC, or (2) prevent the cross connection, such as a fault or failure on one or more of the associated buses. The NRC staff has no objection to the use DG-3 as an alternate source of power to either Division 1 or Division 2 AC buses during a LOOP, provided it is not relied upon as the sole source for mitigating an SBO. In such cases, the RCIC system, instead of the HPCS pump, may be relied upon to control and maintain the RCS inventory during an SBO. The use of RCIC as an SBO mitigation system permits the DG-3 to be used to power safety loads on either division when one DG is in an extended outage. The cross-connection from the DG-3 to either Division 1 or 2 AC buses must be accomplished within 2 hours and have the capability to carry all of the Division 1 or 2 automatically connected loads with the exception of certain loads.

Based on the above, the NRC staff finds that since RCIC is designated as the preferred SBO mitigating equipment, HPCS should no longer be needed for SBO coping. Therefore, DG-3 will not be needed to power HPCS pump and can be utilized to power the safe shutdown loads associated with the inoperable DG.

The NRC staff evaluation of the proposed changes to revise the Required Action for B.4 and certain CTs for Required Actions A.3, B.3.2 and B.4 of TS 3.8.1 as a result of the proposed DG CT extension is as follows:

Changes 1, 2, and 3

A new Required Action B.4.2.1 is added to establish risk management actions for the alternate AC sources with CT of 72 hours. The Required Action B.4.2.2 is added to restore required DG to operable status within 14 days and 17 days from discovery of the failure.
The staff finds these changes to be acceptable because these changes are needed for the 14-day extension of CT for DG-1 and DG-2.

Change 4

Required Action B.3.2 provides one means for addressing the potential for a common-cause failure when one DG is inoperable. If the cause of the initial inoperable DG cannot be confirmed to exist on the remaining DG, the DG needs to be tested within 24 hours.
The licensee has proposed not to perform this test, if the DG was already tested within the past 24 hours. The NRC staff finds the proposed change to be acceptable since testing of the remaining DG within the past 24 hours provides adequate assurance of its continued operability.

Change 5

Renumbering of Required Action B.4 is an administrative change and is acceptable.

Change 6

The licensee has proposed to add "from the discovery of an inoperable DG" to Required Action B.4.1 to limit the CT for an inoperable DG without the risk management actions for the alternate AC sources. The NRC staff finds the proposed change to be acceptable because it avoids entry into a condition prohibited by the TS.

Change 7

The licensee has proposed to revise the CT for Required Action A.3 from "6 days from the discovery of failure to meet LCO" to "6 days from discovery of failure to meet LCO when not associated with Required Action B.4.2.2." The licensee states that this change is needed to avoid conflict with the extended CT of B.4.2.2. The NRC staff finds the proposed change to be acceptable because it simply clarifies that when not associated with the extended CT of B.4.2.2, the second CT for Required Action A.3 should be 6 days.

Change 8

The licensee has proposed to revise the CT for Required Action A.3 to add “17 days from the discovery of failure to meet LCO.” The NRC staff finds the change to be acceptable because the third CT of 17 days establishes a limit on the maximum time allowed for a combination of required AC power sources that are associated with an extended DG CT of B.4.2.2.

Deterministic Conclusion

Based on the information provided by the licensee on the cross-tie between the safety buses and the addition of DG-4 as an additional power source to the battery chargers, the NRC staff has evaluated the proposed use of DG-3 as an alternate AC power source to power the safe shutdown loads associated with the inoperable DG in the event of a LOOP. The NRC staff concludes that the design modification would enhance the capability of the Class 1E electrical distribution systems at CGS to support safety functions in the mitigation of an SBO. The NRC staff finds that extending the CT for an inoperable DG from the current 72 hours to 14 days is acceptable based on the following considerations:

(1) The extended CT will be typically used to perform infrequent (i.e., once every 24 months) diesel manufacturer's recommended inspections and PM activities;

(2) The extended CT would reduce entries into the LCO and reduce the number of DG starts for major DG maintenance activities;

(3) DG-3 will be available and capable of powering either Division 1 or Division 2 loads through the cross-connect within 2 hours in the event of an SBO or LOOP;

(4) The RCIC is designated as the preferred SBO mitigating equipment. The HPCS Pump will be not needed for SBO coping when DG-3 is utilized to power the safe shutdown loads associated with the inoperable DG-1 or DG-2; and

(5) The licensee will implement its CRMP during the extended outage.

Further, the NRC staff believes that the regulatory commitments to implement other restrictions and compensatory measures ensure the availability of the remaining sources of AC power during the extended CT.

3.3 Risk Evaluation

3.3.1 Staff Review Methodology

Per SRP Chapter 19 and Section 16.1, the NRC staff reviewed the submittal using the three-tiered approach and five key principles of risk-informed decisionmaking presented in RG 1.177. The NRC staff also evaluated the traditional engineering analysis.

3.3.2 Key Information Used in the Staff Review

The key information used in the staff's risk evaluation is contained in Attachments 1, 5, 6, and 7 of the license amendment request, as supplemented by the RAI response dated September 1, 2005. The NRC staff also used the licensee's individual plant examination (IPE) and individual plant examination of external events (IPEEE) and associated staff evaluation reports. The staff also referenced the results of the RG 1.200, "An approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," implementation pilot program results, which included CGS.

3.3.3 Comparison Against Regulatory Criteria/Guidelines

The NRC staff's evaluation of the licensee's proposed amendment to extend the CT for DG-1 and DG-2 from 72 hours to 14 days for an inoperable DG using the three-tier approach and the principles outlined in RGs 1.174 and 1.177 including the five key principles are presented in the following sections.

For the quantitative evaluation of risk impacts of extending the current DG-1 and DG-2 CT from 3 days (72 hours) to 14 days, the licensee used the CGS PRA Model, Revision 5. This model is a full-power internal events and fire risk model. The PRA evaluation was performed based on the assumption that a full, extended CT (i.e., 14 days) would be used once per DG per refueling cycle. The current refueling cycle is 24 months (allowing for planned and unplanned plant outage time) for a net assumed cycle length of 670 operating days.

3.3.4 Tier 1: PRA Capability and Insights

The first tier evaluates the impact of the proposed CT extension on plant operational risk, based on the CGS PRA model. The Tier 1 staff review involves two aspects: (1) evaluation of the validity of the PRA and its application to the proposed CT extension, and (2) evaluation of the PRA results and insights stemming from its application.

<u>PRA Capability</u>

To determine whether the PRA used in support of the proposed CT extension is of sufficient quality, scope, and detail, the NRC staff evaluated the relevant PRA information provided by the licensee in their submittal, as supplemented, and considered the findings of recent PRA peer reviews and evaluations. The staff's review of the licensee's submittal focused on the capability of the licensee's PRA model to analyze the risks resulting from the proposed DG-1 and DG-2 CT extension and did not involve an in-depth review of the licensee's PRA, although the NRC staff's RG 1.200 implementation pilot program did provide additional PRA insights.

The CGS Level 1 and Level 2 PRA was developed for the IPE in response to Generic Letter (GL) 88-20 and submitted to the NRC staff by letter dated July 27, 1994. The NRC staff issued its SE for the CGS IPE by letter dated April 8, 1997. The IPE was updated in 1996 as part of the licensee's response to the NRC staff's RAI. The NRC staff concluded that the IPE met the intent of GL 88-20, but identified weaknesses in the licensee's human reliability analysis (HRA) and the staff indicated this weakness could limit its use for other regulatory purposes. With respect to the current submittal, the staff IPE SE identified insights and improvements related to the licensee's submittal including the following:

- Cross-tie of the HPCS DG to power 1E loads in Division 1 or 2 was not provided or credited.
- CGS had a relatively short battery life, 4 hours with credit for load shedding, limiting the time to recover offsite power during an SBO.
- Firewater cross-connect was credited only for those scenarios in which the operators will recognize its need early enough to prevent core damage.

Improvements implemented or under evaluation as identified by the NRC staff IPE SE are as follows:

- SBO depressurization, which involves a procedural change to allow operators to depressurize the reactor vessel prior to battery depletion.

- 500kV backfeed, which involves a plant modification to allow 500kV backfeed within 4 hours when the main generator is disconnected.

The licensee indicated that these issues were evaluated and prioritized by the licensee and the major PRA limitations identified by the IPE SE were incorporated into the PRA in three subsequent updates.

Revision 5 of the model is used for the proposed DG CT extension request and is an update of the original IPE model. The PRA scope addresses internal events and fires during full power operation. The CGS plant PRA has been maintained to reflect plant as-built and as-operated conditions in support of the DG CT extension request and to represent additional plant operating history and component failure data. The current Revision 5 to the CGS PRA includes changes to support the DG CT extension request. The licensee PRA updating process is controlled by procedure PSA-QA-001. The updating process evaluated plant modifications, procedure updates, and peer review team facts and observations (F&Os). The following table documents the updates to the CGS PRA.

Revision	Issue Date	Basis for Revision
0	8/28/92	Original Submittal of IPE
1	7/1994	Requested NRC replace PRA under review with this revision. Updated common cause, LOOP frequencies, HRA, etc.
2	8/1996	Revised to respond to NRC RAIs
3	9/1997	Documentation and modeling improvements for the Boiling-Water Reactor Owners Group (BWROG) PRA certification effort. Peer review performed 11/1997.
4	9/1999	Change incorporated LOOP related comments from the BWROG peer review PRA certification report.
4.1	9/2001	Update Level 1 data based on maintenance rule
4.2	6/2002	Added MOC model and added firewater post containment injection.

Revision	Issue Date	Basis for Revision
5	1/2004	Revised to accommodate the proposed DG CT extension from 72 hours to 14 days. Revisions included incorporation of power uprate, maintenance data, plant modifications, initiating event frequencies, component random failure probabilities, and common-cause failure (CCF). RG 1.200 based independent peer review performed 2/2004.

The CGS PRA underwent a peer review process developed as part of the BWROG PRA certification program in 1997. The peer review team included PRA and system analysts in both PRA development and application. The BWROG PRA peer review guidelines formed the basis for the review. The licensee stated that the F&Os dispositioned from this review resulted in modification of the PRA as indicated in the above table. The BWROG peer certification report was issued in November 1997.

In February of 2004, an independent assessment of the CGS PRA Revision 5 using the guidance of RG 1.200 for trial use and American Society of Mechanical Engineers (ASME) RA-S-2002, including the RA-Sa-2003 Addendum, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," was performed. The peer review team concluded that the CGS PRA Revision 5 was adequate for addressing issues related to the extension of DG CTs with some enhancements, as identified in the licensee's submittal. The peer review identified additional documentation and support improvements needed to meet ASME standard capability Category II, as supplemented by RG 1.200. The A, B, and C F&Os that may impact the proposed extended DG CT were provided to the NRC staff. The peer review generated 62 "A/B" F&Os and 15 "C" level F&Os.

The F&O importance levels are defined as follows:

- Importance Level A - Extremely important and necessary to address to assure the technical adequacy of the PRA or the quality of the PRA or the quality of the PRA update process.

- Importance Level B - Important and necessary to address, but may be deferred until the next PRA update. Consider necessary to meet Capability Category II.

- Importance Level C - Considered desirable to maintain maximum flexibility in PRA applications and consistency in the industry, but not likely to significantly affect results or conclusions.

The licensee provided a summary of the resolution of the "A" and "B" peer review F&Os applicable to the extended DG-1 and DG-2 CT request. By RAI response, the licensee also provided a summary of the resolution of the 15 "C" F&Os. The licensee tracks and prioritizes the F&Os for future PRA updates using Technical Instruction (TI) 4.34, "PRA Configuration Control." The licensee stated that of the 62 "A" and "B" peer review F&Os, 23 F&Os were identified that may have an impact on the amendment request PRA results. The licensee's resolution of these F&Os either indicated that these F&Os had no impact or that a qualitative evaluation, sensitivity analysis, or new calculations showed the particular F&O did not adversely impact the PRA results for the extended DG CT.

The licensee also provided dispositions for the peer review F&Os for the fire at-power PRA. These F&Os were dispositioned as having no impact or that the fire PRA documentation was improved or the PRA was modified or revised to address the F&O.

In addition, based on the NRC staff's RG 1.200 PRA quality pilot site visit, the staff requested Level "C" F&Os that were identified by the peer review as having a potential risk impact on the proposed extended DG CT. The licensee provided a discussion on 15 Level "C" F&Os as part of the licensee's RAI response. All of the Level "C" F&Os, as dispositioned by the licensee, indicated that the Level "C" F&Os did not significantly impact the risk results for the proposed extended DG CT. The dispositions included revisions to the PRA to be incorporated into the next update, additional clarification and additions to documentation and additional analysis to show that the Level "C" F&Os had limited impact on the proposed DG CT extension.

In a letter dated June 26, 1995, the licensee submitted its response to GL 88-20, Supplement 4, IPEEE for Severe Accident Vulnerabilities. The licensee responded to the RAIs on March 30, 1998, and June 17, 1999. Additional information was provided on January 24, 2001. The NRC staff issued its SE for the CGS IPEEE by letter dated February 26, 2001. On the basis of its review, the NRC staff finds that the aspects of seismic, fires, and high winds, floods, transportation and other external events were adequately addressed.

During the week of June 7, 2004, an NRC team consisting of NRC staff and contractor support reviewed the CGS PRA model documentation, industry peer review results, and the licensee's self-assessment report to determine the effectiveness of the ASME PRA Standard, RA-Sa-2003 addendum to RA-S-2002, RG 1.200, and the self assessment process. The RG 1.200 implementation pilot program objectives were not specifically geared to the licensee's amendment request or the determination of the licensee's PRA quality, but to the determination of whether RG 1.200, SRP 19.1, and the ASME standard provide adequate guidance to demonstrate the technical adequacy of a PRA. The NRC staff's assessment of the supporting requirement capabilities was in general agreement with the licensee's self assessment. Some of the differences were attributed to differences in interpretation of how the intent of the requirement was to be met, the lack of PRA documentation specifically indicating a requirement was met, and the limited NRC staff review time compared to a licensee's peer review and self assessment, which may have caused the NRC staff to conclude a requirement was not met when a more, lengthy, in depth review may have changed this conclusion.

<u>Other Issues</u>

Shutdown risk was not evaluated for the DG CT extension request since the CT extension request is only applicable in modes 1, 2, and 3.

The licensee also addressed key assumptions and uncertainty with sensitivity analysis performed to address peer review comments. Assumptions and key areas of uncertainty evaluated included the residual heat removal system time in suppression pool cooling mode, grid availability, grid transient stability, grid maintenance and monitoring, HPCS mission time, recirculation pump seal leakage, human error probabilities, and the subdividing of motor operated valves and motor driven pumps into running and standby groups. The licensee's analysis showed that these assumptions do not significantly impact the proposed extended DG CT.

3.3.5 PRA Insights

Based on the CGS PRA model, the addition of risk management actions and the availability of DG-4, the licensee calculated values for ΔCDF, ICCDP, ΔLERF, and ICLERP for the proposed 14-day DG-1 and DG-2 CT. The evaluation was performed assuming that an extended 14-day CT would be applied to each DG once per fuel cycle, which is currently 24 months. The results of the risk evaluations are presented in the tables below for PM and CM, and compared to the acceptance guidelines of RG 1.174 and RG 1.177.

PM is defined as planned maintenance and not the direct result of equipment failure. The licensee assumed that plant risk is minimized pursuant to the requirements of the Maintenance Rule (10 CFR 50.65(a)(4)). Consistent with the Maintenance Rule, during DG PM activities, it is assumed that CCF contributors that affect both DG-1 and DG-2 are not applicable and normal risk management measures are implemented, including that DG-4 is available. These measures also minimize the testing and maintenance (T&M) activities on other risk significant plant equipment. Specifically, the licensee assumed that no T&M on specific equipment that affects the reliability of the train associated with the operable DGs or with offsite power sources will be scheduled during the DG out-of-service time.

CM is an emergent maintenance condition created by equipment failure. Because CM is not planned, plant risk may be increased due to plant conditions or configurations that may not be considered when PM is scheduled on the subject equipment. For DG-1 and DG-2 CM, it is assumed by the licensee that CCF contributors that affect either DG are increased due to the equipment failure requiring CM. The results shown below incorporate the maximum time allowed for the risk management action TS LCO 3.8.1, Required Action B.4.2.1, to stage DG-4 (72 hours). The 24-hour LCO 3.8.1, Action B.3.1, which requires that the operable DGs are not inoperable due to a CCF is not specifically incorporated into the licensee's risk results. The requirement to perform LCO 3.8.1, Action B.3.1, is not changed and would, therefore, prevent entry into an extended CT should a DG become inoperable due to a common cause. In addition, LCO 3.8.1 Condition E requires restoration of one DG to operable status within 2 hours for DG-1 or DG-2 and within 24 hours for DG-3, if found inoperable due to a CCF. Therefore, the impact of not including the CCF CT into the risk evaluation for the proposed extended DG-1 and DG-2 CT is not considered significant.

14-DAY PREVENTIVE MAINTENANCE DG CT WITH DG-4		
Risk Metric	**Acceptance Guideline***	**PRA Results**
ΔCDF	< 1.0E-6/reactor-year	3.09E-7/reactor-year
ICCDP (DG-1)	< 5.0E-7	2.76E-7
ICCDP (DG-2)	< 5.0E-7	2.92E-7
ΔLERF	< 1.0E-7/reactor-year	1.21E-9/reactor-year
ICLERP (DG-1)	< 5.0E-8	1.46E-9

14-DAY PREVENTIVE MAINTENANCE DG CT WITH DG-4		
Risk Metric	**Acceptance Guideline***	**PRA Results**
ICLERP (DG-2)	< 5.0E-8	7.67E-10

**Acceptance guidelines for very small changes. Acceptance guidelines for small changes are an order of magnitude higher.*

14-DAY CORRECTIVE MAINTENANCE DG CT WITH DG4		
Risk Metric	**Acceptance Guideline***	**PRA Results**
ΔCDF	< 1.0E-6/reactor-year	3.58E-7/reactor-year
ICCDP (DG-1)	< 5.0E-7	3.19E-7
ICCDP (DG-2)	< 5.0E-7	3.38E-7
ΔLERF	< 1.0E-7/reactor-year	1.44E-9/reactor-year
ICLERP (DG-1)	< 5.0E-8	1.62E-9
ICLERP (DG-2)	< 5.0E-8	1.02E-9

**Acceptance guidelines for very small changes. Acceptance guidelines for small changes are an order of magnitude higher.*

The risk values in both the PM and the CM tables are within the RG 1.177 and RG 1.174 acceptance guidelines for a very small incremental increase in risk (i.e., ICCDP and ICLERP) and a very small increase in the change in risk (i.e., ΔCDF and ΔLERF).

DG-4 is a TS LCO-controlled component that requires DG-4 be established as a risk management action. The proposed DG-1 and DG-2 extended CT to 14 days requires the availability of DG-4 in order to extend the CT beyond 72 hours. In addition, if DG-4 were to become unavailable during an extended DG-1 or DG-2 CT, the CT would be 72 hours from the point when DG-4 becomes unavailable.

<u>DG-3 Cross Connect</u>

In addition to DG-4 being staged to provide AC power to the battery chargers the licensee is also modifying DG-3 such that it can be cross connected to either the Division 1 or Division 2 buses. The addition of the cross connect feature provides additional capability to that already provided by the addition of DG-4 in dealing with an SBO. DG-3 is capable of providing power to one train of selected safe shutdown equipment. Procedures establish the loads that can be connected within the capacity of DG-3. However, the licensee did not credit these changes to DG-3 in the SBO analysis and the CGS SBO coping time will remain at 4 hours. However, the addition of DG-4 and the cross-tie to DG-3 provide an increased SBO coping ability.

The CGS FSAR states that RCIC is the preferred SBO mitigation system. However, RCIC is not credited in the licensee's SBO analysis. Rather, the SBO analysis for CGS considers the RCIC system as backup to HPCS during an SBO. The addition of the DG-3 cross connect is not credited in the licensee's risk analysis for the proposed DG-1 and DG-2 extended CT, but it has been evaluated with regard to the risk impact of performing the cross connect at different times during an SBO. The licensee's risk analysis looked at enabling the DG-3 cross connect at either 2 hours or 6 hours with the assumption that DG-4 is available and maintaining the Division 1 batteries. In this case the licensee's analysis indicates that it is preferable to cross-tie DG-3 later in the sequence. The situation changes, however, if DG-4 is not available and offsite or onsite sources have not been recovered. Then the analysis shows that an earlier transition to DG-3 is preferred.

Previous CGS risk-informed submittals were investigated for cumulative risk impact with respect to the proposed DG-1 and DG-2 extended CT. The licensee determined through a sensitivity analysis and the updated PRA Revision 5 model that an extended DG-1 and DG-2 CT had a very small impact on the risk-informed inservice inspection program. In addition, the licensee also confirmed that LCO 3.0.4, which prohibits a mode change for selected high-risk systems or SR 3.0.3, which covers a missed surveillance, were not impacted with the proposed DG-1 and DG-2 extended CT, with DG-4 in place.

<u>Fire Risk</u>

The fire PRA analysis results represent normal high-pressure systems protected with risk management controls. The risk impact of DG-4 is not included in the analysis. For the fire analysis the licensee used the loss of feedwater event tree instead of the LOOP trees. This is consistent with the previous IPEEE fire analysis where fires that impact power conversion systems used the loss of feedwater event tree. The licensees analysis assumes that for a failure of offsite power or the DG power failed, no recovery is credited within the 24-hour mission time. The use of the feedwater event tree simplifies this approach. The licensee PRA results indicate that DG-2 is significantly more risk sensitive with respect to fires than DG-1. The licensee noted that DG-2 is part of the 10 CFR Part 50, Appendix R safe shutdown protected train; this contributes to the asymmetry in the DG-1 and DG-2 results.

The fire PRA analysis results are presented below:

DG EXTENDED CT FIRE PRA ΔCDF and ICCDP RESULTS		
Risk Metric	**Acceptance Guideline***	**PRA Results**
ΔCDF (DG-1)	< 1.0E-6/reactor-year	9.0E-8/reactor-year
ICCDP (DG-1)	< 5.0E-7	3.45E-9
ΔCDF (DG-2))	< 1.0E-6/reactor-year	4.42E-6/reactor-year
ICCDP (DG-2)	< 5.0E-7	1.7E-7

**Acceptance guidelines for very small changes. Acceptance guidelines for small changes are an order of magnitude higher.*

Per the IPEEE, the licensee's fire analysis used a combination of a PRA and some portions of Electric Power Research Institute's fire-induced vulnerability evaluation methodology and an existing fire hazards analysis performed in compliance with Appendix R. The fire CDF in the

IPE is not dominated by any single fire. The fire PRA results shown above are within the RGs 1.174 and 1.177 acceptance guideline values for a very small change except for the estimate for DG-2 ΔCDF with DG-2 out-of-service. The estimate for ΔCDF for DG-2 falls within the RG 1.174 guidelines for a small change. Based on RG 1.174 guidance for changes in CDF within the range of 1E-6 to 1E-5, an application would be considered only if the total CDF is less than 1E-4/year. This is the case for CGS as the total CDF remains within the RG 1.174 acceptance guidelines when internal events PRA and fire PRA results are considered. In addition, the risk benefit of adding DG-4 or the ability to cross-tie DG-3 is not included in the fire PRA results, which is conservative.

The licensee's fire LERF assessment was estimated using a modified internal events Level 2 PRA and quantifying the Level 2 model using fire damage state frequencies derived from the fire PRA. Using this methodology the licensee estimated a fire LERF of 3.36E-7/year. The estimated results for the proposed extended DG-1 and DG-2 CT are shown below.

DG EXTENDED CT FIRE PRA LERF and ICLERP RESULTS		
Risk Metric	**Acceptance Guideline***	**PRA Results**
ΔLERF (DG-1)	< 1.0E-7/reactor-year	8.20E-9/reactor-year
ICLERP (DG-1)	< 5.0E-8	3.15E-10
ΔLERF (DG-2))	< 1.0E-7/reactor-year	8.61E-8/reactor-year
ICLERP (DG-2)	< 5.0E-8	3.3E-9

**Acceptance guidelines for very small changes. Acceptance guidelines for small changes are an order of magnitude higher.*

Again, the licensee fire PRA LERF results indicate that DG-2 is more risk sensitive with respect to fires than DG-1, but both DG-1 and DG-2 estimates for ΔLERF meet the RG 1.174 acceptance guidelines for a very small change. The licensee estimates for ICLERP meet the RG 1.177 acceptance guidance for a small change. With consideration for both internal events and fire risk, the estimates for LERF and ICLERP are still within the acceptance guidelines for a small change. Based on the above, the NRC staff finds that the licensee has adequately addressed the risk impact from internal fires with respect to the proposed extended DG-1 and DG-2 CT.

Other External Events

The licensee's IPEEE submittal included a seismic PRA. The licensee estimated the mean seismic CDF to be 2.1E-5/year as referenced in the IPEEE and submittal. The IPEEE indicated that a LOOP contributes about 77 percent of the seismic CDF. The dominant sequence is a LOOP with failure of both DGs. The NRC staff Safety Evaluation Report (SER) indicated that the dominant basic events are loss of critical switchgear cooling, loss of diesel generator controls, loss of screened equipment, and failure of the DG-1 and DG-2 to run for 10 hours. The seismic risk is dominated by seismic induced DG failures, which would be highly correlated, limiting the impact of the proposed extended DG CT. Of the seismic related improvements identified by the staff in the IPEEE, the NRC staff SER indicated that the licensee had addressed these issues. The IPEEE indicated that the seismic PRA satisfied the objectives of GL 88-20. The impact of seismic DG failures should not impact the proposed DG-1 and DG-2

CT, and seismic LOOP events are estimated to be significantly less than weather-related LOOP events.

The IPEEE estimated a CDF due to tornadoes to be 1.0E-7/year and was screened from the analysis based on the fact that all safety-related structures are protected against high winds, tornado wind loads, and tornado-generated missiles; the licensee meets the guidance of RG 1.76 and the 1975 SRP criteria.

The external flood evaluations did not find any vulnerability to external floods. The IPEEE results also show that the licensee's evaluation of probable maximum precipitation did not indicate any plant vulnerability.

Transportation hazards from postulated transportation accidents were screened out as not significant. The licensee evaluated lightning strikes and range fires, and concluded that lightning and range fires did not pose a threat to CGS. The licensee also evaluated the effects of volcanic activity and concluded that potential volcanic activity including ash fall did not present a significant threat to the plant.

The NRC staff SER concluded that the IPEEE was complete with regard to the information requested by GL-88-20.

Considering the information provided in the licensee's submittal, the NRC staff finds that there is reasonable assurance that the total CDF is not greater than 1E-4/reactor-year. Thus, the risks associated with external events, especially in consideration of the compensatory actions committed to by the licensee, are not expected to impact the staff's conclusion regarding the acceptability of the proposed DG-1 and DG-2 CT extension to 14 days.

3.3.6 Tier 2: Avoidance of Risk-Significant Plant Configurations

A licensee must provide reasonable assurance that risk significant plant equipment outage configurations will not occur when specific plant equipment is out-of-service in accordance with the proposed TS change. The avoidance of risk-significant plant configurations limits potentially high-risk configurations that could exist if equipment, in addition to that associated with the proposed TS change, is simultaneously removed from service or other risk-significant operational factors such as concurrent system or equipment testing are involved. Therefore, Tier 1 helps ensure that appropriate restrictions are placed on dominant risk-significant configurations relevant to the proposed TS change.

The licensee's Tier 2 evaluation identified the following Tier 2 conditions as a result of the proposed extended DG-1 and DG-2 CT extension.

1. The DG extended CT will not be entered for scheduled maintenance purposes if severe weather conditions are expected.

2. The condition of the offsite power supply and transmission yard, including transmission lines and the stability of the Federal Columbia River Transmission System, will be evaluated through contact with the BPA dispatcher. If the grid stress conditions are high or forecasted to be high resulting in a significant potential for the grid to not be able to remain in stable condition or supply post

trip offsite power minimum voltages, the extended completion time will not be entered to perform elective maintenance. The BPA dispatcher will be contacted on at least a daily basis during the extended DG CT to assure that conditions that create the potential for developing grid instabilities do not exist.

3. No elective maintenance will be scheduled within the transmission yard that would challenge the TR-S or TR-B connections or offsite power availability during the proposed extended DG CT.

4. Operating crews will be briefed on the DG work plan, with consideration given to key procedural actions that would be required in the event of a LOOP or SBO.

5. While in the proposed extended DG CT, the following systems are risk significant during the extended DG CT period and will be protected so that elective maintenance and testing are not performed:

   - Cross train DGs, their support systems, and their respective Service Water Systems

   - TR-S and TR-B and the associated breakers and relay logic (protective and control)

   - HPCS system

   - RCIC system

6. While in the proposed extended DG CT, additional elective equipment maintenance or testing that requires any other risk significant equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.

7. Emergent Conditions that result in the protected systems being challenged will be managed to minimize the risk impact.

The above Tier 2 conditions are identified in Section 4.0 of this SE as regulatory commitments. The licensee stated that associated procedures will be revised to implement these commitments.

3.3.7 Tier 3: Risk-Informed Configuration Risk Management

A Tier 3 program ensures that while a DG is in an LCO condition, additional activities will not be performed that could further degrade the capability of the plant to respond to a condition the inoperable DG or system was designed to mitigate, and as a result, increase plant risk beyond that assumed by the risk-informed licensing action. Tier 3 programs: (1) ensure that additional maintenance does not increase the likelihood of an initiating event intended to be mitigated by the out-of-service equipment, (2) evaluate the effects of additional equipment out-of-service during DG maintenance activities that would adversely impact DG CT risk such as from redundant or associated systems or components, and (3) evaluate the impact of maintenance on equipment or systems assumed to remain operable by the DG CT analysis.

The licensee has a developed a CRMP based on 10 CFR 50.65(a)(4). This program is a procedure based, risk-informed assessment process to manage the risk associated with planned and unplanned (emergent) plant maintenance activities. CGS procedure PPM 1.5.14, "Risk Assessment and Management for Maintenance/Surveillance Activities," controls this process, which uses methods based on NUMARC 93-01 guidelines. The CRMP uses an integrated approach of both quantitative and qualitative methods to identify risk-significant plant maintenance equipment outage configurations. The CRMP performs 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. The program evaluates defense-in-depth of key plant safety functions associated with the maintenance activity. In addition, the licensee’s Tier 2 commitments specify additional compensatory measures to assess and manage the risk for an extended DG-1 or DG-2 CT.

The qualitative assessment considers equipment unavailability, operational activities, such as testing or load dispatching, weather conditions, specific safety functions, and maintenance activities for the plant maintenance configuration. Transients are also evaluated for impact on initiating event frequency and mitigation capability.

The quantitative assessment is based on the licensee’s PRA as implemented in ORAM-SENTINAL, which includes provisions for performing a configuration-dependent assessment of the overall impact on risk from plant configurations associated with maintenance activities that remove equipment from service.

The licensee established risk management actions for each plant risk level to manage the risk of the maintenance activity. These risk management actions include measures to increase risk awareness during maintenance activities, reduce the duration of the maintenance, minimize the magnitude of the risk increase, and provide limitations on the entry into specific risk levels.

Based on the above, the NRC staff finds the licensee’s Tier 3 program for complying with 10 CFR 50.65(a)(4) is consistent with the guidance of Chapter 16.1 of the SRP and RG 1.177 and, thus, is acceptable.

3.3.8 Implementation and Monitoring Program

RG 1.174 states that an implementation and monitoring plan should be developed to ensure that the impact of the proposed change continues to reflect the actual reliability and availability of the DGs evaluated to support the proposed extended DG-1 and DG-2 CT. Monitoring performed in conformance with the Maintenance Rule of 10 CFR 50.65 can be used when such monitoring is sufficient for the SSCs affected by the risk-informed application. Therefore, to ensure that the proposed extended DG-1 and DG-2 CT does not degrade operational safety over time should equipment not meet its performance criteria, an evaluation is required as part of the Maintenance Rule, 10 CFR 50.65.

DG reliability and availability for DG-1 and DG-2 are monitored and evaluated per the Maintenance Rule (10 CFR 50.65) under CGS procedure PPM 1.5.11, "Maintenance Rule Program," and PPM 1.5.12, "Diesel Generator Reliability Program," to ensure that pre-established reliability and availability goals will continue to be met. In addition, the licensee also stated that the DG availability used in the PRA is conservative with respect to the proposed 14 day CT, actual past performance of the DGs, and the expected DG availability after the proposed 14 day CT is implemented. The DGs are currently in the 10 CFR 50.65(a)(2) category and are meeting established performance goals. DG reliability and availability is also monitored and periodically evaluated in relation to the maintenance rule and assumed SBO values. Performance of DG-1 and DG-2 online maintenance utilizing the proposed extended CT is not anticipated to result in exceeding the current established Maintenance Rule criteria for the DGs.

DG-4 has been included in the scope of the 10 CFR 50.65(a)(2) Maintenance Rule and will have performance criteria established through an expert panel. The performance criteria will include reliability and availability goals based on the risk significance assigned by the expert panel and the assumptions used in the PRA and updated in accordance with the PRA update program. DG-4 will undergo periodic testing and inspection to confirm: (1) a minimum of 24 hours of fuel is available, (2) DG-4 starts normally and obtains proper speed and voltage regulation, and (3) DG-4 runs at full load for 1 hour while maintaining proper voltage and frequency.

Based on the above, the NRC staff finds the licensee's implementation and monitoring program is consistent with the guidance of RG 1.174 and provides a means to adequately track performance such that the conclusions that support the proposed extended DG-1 and DG-2 CT will remain valid; it is, therefore, acceptable.

3.4 Comparison Against Regulatory Guidelines

The NRC staff has determined that the licensee's evaluation of the impacts of the F&Os identified from the independent RG 1.200 peer review are adequate and that these F&Os do not change the risk results in any substantial manner. Thus, the NRC staff concludes that the CGS PRA, as supplemented, is acceptable for this application.

The CGS PRA risk evaluation results are consistent with the RG 1.177 and RG 1.174 acceptance guidelines, indicating a small increase in risk due to the extended DG-1 and DG-2 CT from 72 hours to 14 days. This conclusion is further supported when consideration is given to the risks associated with CGS external events, and additional compensatory actions committed to by the licensee.

3.5 Staff Findings

In summary, the NRC staff finds that the licensee's proposed changes to TS 3.8.1 to extend the DG-1 and DG-2 CT from 72 hours to 14 days is acceptable based on meeting the acceptance guidelines of RG 1.174 and RG 1.177.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments for limiting plant vulnerabilities during the extended DG outages.

1. The DG extended CT will not be entered for scheduled maintenance purposes if severe weather conditions are expected.

2. The condition of the offsite power supply and transmission yard, including transmission lines and the stability of the Federal Columbia River Transmission System, will be evaluated through contact with the BPA dispatcher. If the grid stress conditions are high or forecasted to be high resulting in a significant potential for the grid to not be able to remain [in] stable condition or supply post trip offsite power minimum voltages, the extended completion time will not be entered to perform elective maintenance. The BPA dispatcher will be contacted on at least a daily basis during the extended DG Completion Time to assure that conditions that create the potential for developing grid instabilities do not exist.

3. No elective maintenance will be scheduled within the transformer yard that would challenge the TR-S or TR-B connections or offsite power availability during the extended DG CT.

4. Operating crews will be briefed on the DG work plan, with consideration given to key procedural actions that would be required in the LOOP or SBO.

5. While in the proposed extended DG CT, the following systems are risk significant during the extended DG CT period and will be protected so that elective maintenance and testing are not performed:

   Cross train DGs, their support systems, and their respective Service Water Systems

   TR-S and TR-B and the associated breakers and relay logic (protective and control)

   HPCS system

   RCIC system

6. Any testing and maintenance activities that must be performed while the extended DG CT is in effect are required to have 10 CFR 50.65(a)(4) evaluation performed.

7. While in the proposed extended DG CT, additional elective equipment maintenance or testing that requires any other risk significant equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.

8. Emergent conditions that result in the protected systems being challenged will be managed to minimize the risk impact.

9. Incorporate modeling and PRA Documentation changes identified in Level C F&Os (Nos. 1-4 and 6-14) and the modeling improvements to the fault trees of HPCS and RCIC into the next PRA upgrade.

10. The battery capacity will be verified prior to entry into the extended Completion Time by the following:

- The results of the last battery capacity surveillance was greater than or equal to 100 [percent],
- The battery surveillances are current.

Short time excursions in battery parameters outside surveillance limits will not invalidate the risk management compensatory measure commitment as specific TS Actions exist to restore the conditions within a reasonable time.

A restraint in the battery load calculation, maintains the 6 hour capability for the PRA basis.

11. For planned maintenance, DG-4 and DG-3 cross connect will be verified to be available and any associated surveillance procedures are current prior to taking the DG out of service. For emergent conditions (repair), DG-4 and DG-3 will be verified to be available as soon as practicable, but prior to exceeding 72 hours.

12. Incorporate the administrative controls on the use of DG-3 and DG-4 into the SBO procedure, including the required load shedding of Division 1 and 2 125 volt batteries, the specific configuration of floor fans and door alignments used in the thermal calculation, and configuration of the buses to facilitate the energizing of their use. Also, provide a section for isolating the Division 1 or 2 bus and re-energizing the HPCS system. Procedures will be completed and training provided prior to entry into the extended DG CT.

13. Perform the periodic surveillance and maintenance procedures for verifying DG-4 is able perform its risk management function. Procedures will be issued and training provided prior to entry into the extended DG CT.

14. Revise planning procedures to obtain the projected grid conditions when planning an online elective DG maintenance. Assure that periods of stable grid conditions are chosen and that planning of maintenance activities by BPA on the grid are coordinated with DG outage planning to avoid conflict.

15. Establish performance criteria for DG-4 in accordance with the Maintenance Rule requirements. The development of these performance criteria will be based on assumptions used in the PRA and updated in accordance with the PRA update program.

16. Verify through training and simulation the ability to accomplish the energizing of the cross connection from DG-3 to the Division 1 or Division 2 ESF switchgear bus (SM-7 or SM-8, respectively) within two [2] hours in accordance with SBO procedure.

17. Establish procedures that during entry into the extended DG CT to direct full implementation of the DG-3 cross connect to Division 1 or Division 2 switchgear (SM-7 or SM-8) within two [2] hours of a LOOP or SBO unless plant conditions dictate otherwise.

18. Establish procedures to implement the Columbia Fire Protection Program compensatory actions to restrict transient ignition sources and establish hourly fire tours in certain key fire areas during the DG extended completion time.

The NRC staff finds that reasonable controls for the implementation and subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee's administrative processes, including its commitment management program.

PRA Conclusion

The risk impact of the proposed extended DG-1 and DG-2 14-day CT, as estimated by ΔCDF, ΔLERF, ICCDP, and ICLERP, is consistent with the acceptance guidelines specified in RG 1.174, RG 1.177, and staff guidance outlined in Chapter 19.0 and Section 16.1 of NUREG-0800. The NRC staff finds that the PRA and risk analysis approach used by the licensee to estimate the risk impacts were reasonable and of sufficient quality for the proposed amendment request. The Tier 2 evaluation did identify risk-significant plant equipment configurations requiring TS, procedure, or compensatory measures. These were identified by the licensee and included as licensing commitments. DG reliability and availability will also be monitored and assessed under the Maintenance Rule (10 CFR 50.65) to confirm that performance continues to be consistent with the analysis assumptions used to justify the extended DG-1 and DG-2 14-day CTs. Based on the licensee’s risk-informed assessment discussed in this SE, the NRC staff finds that the proposed extension of the DG-1 and DG-2 CT to 14 days at CGS is acceptable based on the fact that the increase in plant risk is small and consistent with the acceptance guidelines of RG 1.177 and RG 1.174.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Washington State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (69 FR 34699). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the

Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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