

May 17, 2002

Mr. H. L. Sumner, Jr.
Vice President - Nuclear
Hatch Project
Southern Nuclear Operating
Company, Inc.
Post Office Box 1295
Birmingham, Alabama 35201-1295

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2 RE: ISSUANCE OF
AMENDMENTS (TAC NOS. MB2886 AND MB2887)

Dear Mr. Sumner:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 231 to Renewed Facility Operating License DPR-57 and Amendment No. 172 to Renewed Facility Operating License NPF-5 for the Edwin I. Hatch Nuclear Plant, Units 1 and 2. The amendments consist of changes to the Technical Specifications (TS) in response to your application dated August 31, 2001, as supplemented by letters dated November 15, 2001, February 20 (two letters), February 21, and March 14, 2002.

The amendments revise the TS to extend the completion times for the required actions associated with restoring inoperable emergency diesel generators.

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

Sincerely,

/RA/

Leonard N. Olshan, Senior Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-321 and 50-366

Enclosures:

1. Amendment No. 231 to DPR-57
2. Amendment No. 172 to NPF-5
3. Safety Evaluation

cc w/encls: See next page

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DISTRIBUTION:

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cc w/encls: See next page

**See previous concurrence

*No major changes to SE

ADAMS Accession No.: ML021060531

OFFICE	PDII-1/PM	PDII-1/LA	OGC**	EEIB*	SPSB/SC**	PDII-1/SC
NAME	LOlshan	CHawes	RWeismam	CHolden	MReinhart	JNakoski
DATE	05/15/02	05/15/02	5/13/002	01/17/02	4/23/02	05/15/02

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SOUTHERN NUCLEAR OPERATING COMPANY, INC.

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

DOCKET NO. 50-321

EDWIN I. HATCH NUCLEAR PLANT, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 231

Renewed License No. DPR-57

1. The Nuclear Regulatory Commission (the Commission) has found that:
 - A. The application for amendment to the Edwin I. Hatch Nuclear Plant, Unit 1 (the facility) Renewed Facility Operating License No. DPR-57 filed by Southern Nuclear Operating Company, Inc. (the licensee), acting for itself, Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the owners), dated August 31, 2001, as supplemented by letters dated November 15, 2001, February 20 (two letters) February 21, and March 14, 2002, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;
 - 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 hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-57 is hereby amended to read as follows:

- (2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 231, are hereby incorporated in the license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

John A. Nakoski, Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: May 17, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 231

RENEWED FACILITY OPERATING LICENSE NO. DPR-57

DOCKET NO. 50-321

Replace the following pages of the Appendix A Technical Specifications and associated bases with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

<u>Remove</u>	<u>Insert</u>
3.8-2	3.8-2
3.8-3	3.8-3
3.8-4	3.8-4
3.8-5	3.8-5
3.8-6	3.8-6
B 3.8-7	B 3.8-7
B 3.8-9	B 3.8-9
B 3.8-10	B 3.8-10
B 3.8-11	B 3.8-11
B 3.8-12	B 3.8-12
B 3.8-13	B 3.8-13
B 3.8-14	B 3.8-14
B 3.8-15	B 3.8-15
B 3.8-16	B 3.8-16
B 3.8-17	B 3.8-17
B 3.8-18	B 3.8-18
B 3.8-19	B 3.8-19
B 3.8-20	B 3.8-20
B 3.8-21	B 3.8-21
B 3.8-22	B 3.8-22
B 3.8-23	B 3.8-23
B 3.8-24	B 3.8-24
B 3.8-25	B 3.8-25
B 3.8-26	B 3.8-26
B 3.8-27	B 3.8-27
B 3.8-28	B 3.8-28
B 3.8-29	B 3.8-29
B 3.8-30	B 3.8-30
B 3.8-31	B 3.8-31
B 3.8-32	B 3.8-32
B 3.8-33	B 3.8-33
B 3.8-34	B 3.8-34
B 3.8-35	B 3.8-35
B 3.8-35a	--
B 3.8-35b	--

SOUTHERN NUCLEAR OPERATING COMPANY, INC.

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

DOCKET NO. 50-366

EDWIN I. HATCH NUCLEAR PLANT, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 172
Renewed License No. NPF-5

1. The Nuclear Regulatory Commission (the Commission) has found that:
 - A. The application for amendment to the Edwin I. Hatch Nuclear Plant, Unit 2 (the facility) Renewed Facility Operating License No. NPF-5 filed by Southern Nuclear Operating Company, Inc. (the licensee), acting for itself, Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the owners), dated August 31, 2001, as supplemented by letters dated November 15, 2001, February 20 (two letters) February 21, and March 14, 2002, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;
 - 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 hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-5 is hereby amended to read as follows:

- (2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 172, are hereby incorporated in the license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

John A. Nakoski, Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: May 17, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 172

RENEWED FACILITY OPERATING LICENSE NO. NPF-5

DOCKET NO. 50-366

Replace the following pages of the Appendix A Technical Specifications and associated bases with the attached revised pages. The revised pages are identified by amendment number and contain vertical lines indicating the areas of change.

<u>Remove</u>	<u>Insert</u>
3.8-2	3.8-2
3.8-3	3.8-3
3.8-4	3.8-4
3.8-5	3.8-5
3.8-6	3.8-6
B 3.8-7	B 3.8-7
B 3.8-9	B 3.8-9
B 3.8-10	B 3.8-10
B 3.8-11	B 3.8-11
B 3.8-12	B 3.8-12
B 3.8-13	B 3.8-13
B 3.8-14	B 3.8-14
B 3.8-15	B 3.8-15
B 3.8-16	B 3.8-16
B 3.8-17	B 3.8-17
B 3.8-18	B 3.8-18
B 3.8-19	B 3.8-19
B 3.8-20	B 3.8-20
B 3.8-21	B 3.8-21
B 3.8-22	B 3.8-22
B 3.8-23	B 3.8-23
B 3.8-24	B 3.8-24
B 3.8-25	B 3.8-25
B 3.8-26	B 3.8-26
B 3.8-27	B 3.8-27
B 3.8-28	B 3.8-28
B 3.8-29	B 3.8-29
B 3.8-30	B 3.8-30
B 3.8-31	B 3.8-31
B 3.8-32	B 3.8-32
B 3.8-33	B 3.8-33
B 3.8-34	B 3.8-34
B 3.8-35	B 3.8-35
B 3.8-35a	--
B 3.8-35b	--

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
RELATED TO
AMENDMENT NO. 231 TO RENEWED FACILITY OPERATING LICENSE DPR-57
AND AMENDMENT NO. 172 TO RENEWED FACILITY OPERATING LICENSE NPF-5
SOUTHERN NUCLEAR OPERATING COMPANY, INC., ET AL.
EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2
DOCKET NOS. 50-321 AND 50-366

1.0 INTRODUCTION

By letter dated August 31, 2001, as supplemented by letters dated November 15, 2001, February 20 (two letters), February 21, and March 14, 2002, Southern Nuclear Operating Company, Inc. (SNC, the licensee), et al., proposed license amendments to change the Technical Specifications (TS) for the Edwin I. Hatch Nuclear Plant (Hatch), Units 1 and 2. The proposed changes would extend the completion times for the required actions associated with restoring an inoperable emergency diesel generator (DG). The supplemental letters dated November 15, 2001, February 20 (two letters), February 21, and March 14, 2002, provided clarifying information that did not change the scope of the August 31, 2001, application nor the initial proposed no significant hazards consideration determination.

In addition, the staff met with the licensee on March 8, 2002, to discuss the August 31, 2001, proposed license amendments, as documented in the meeting summary dated April 2, 2002. By letter dated February 22, 2002, the staff issued Amendments 227 and 169 for Units 1 and 2. The amendments revised TS 3.8.1.B, on a one-time basis, to extend from 7 days to 14 days the completion time for the required actions associated with restoration of the 1B DG.

2.0 BACKGROUND

Hatch, Units 1 and 2 are designed and operated consistent with the defense-in-depth philosophy. The Class 1E ac electrical power distribution system ac sources consist of the offsite power sources (preferred power sources, normal and alternate) and the onsite standby power sources. The design of the ac electric power system provides independence and redundancy to ensure an available source of power to the emergency safety features (ESF) systems. The Class 1E ac distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two preferred offsite power supplies and a single DG. Since the

ENCLOSURE

station has diverse power sources available to cope with a loss of the preferred ac, 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.

There are a total of five DGs, two per unit and one shared. There are three 4160 volt Class 1E safety buses on each unit. Each unit's 4160 volt buses E and G have a dedicated DG. The 4160 volt F bus on each unit shares a common DG. The logic is preselected to a particular unit to cover simultaneous undervoltage conditions on both 4160 volt F buses. This accounts for the dual unit loss of offsite power (LOSP) case. The shared DG, whether selected to that unit or not, will go to the undervoltage 4160 volt F bus during single unit LOSP or loss of an individual 4160 volt F bus. If during dual unit F bus undervoltage or LOSP, one unit also has a loss-of-coolant accident (LOCA) signal, the shared DG will go to that unit.

3.0 EVALUATION

The proposed TSs changes are as follows:

1. Change Specification 3.8.1, Required Action A.3, second Completion Time for restoration of a required offsite circuit to OPERABLE status from "10 days from discovery of failure to meet Limiting Condition for Operation (LCO) 3.8.1.a, b, or c" to "17 days from discovery of failure to meet LCO 3.8.1.a, b, or c."
2. Change Specification 3.8.1, Required Action B.4, first Completion Time for restoration of a unit's A or C DG from "72 hours for a Unit 1[2] DG" to "72 hours for a Unit 1[2] DG with the swing DG not inhibited AND 14 days for a Unit 1[2] DG with the swing DG inhibited from automatically aligning to Unit 2[1]."
3. Change Specification 3.8.1, Required Action B.4, second Completion Time for restoration of the swing DG from "7 days for the swing DG" to "14 days for the swing DG."
4. Change Specification 3.8.1, Required Action B.4, third Completion Time for restoration of a unit's A or C DG or the swing DG from "10 days from discovery of failure to meet LCO 3.8.1.a, b, or c" to "17 days from discovery of failure to meet LCO 3.8.1.a, b, or c."
5. Change Specification 3.8.1, Required Action C.4, Completion Time for restoration of a required other unit's DG from "7 days" to "7 days with the swing DG not inhibited AND 14 days with the swing DG inhibited from automatically aligning to Unit 1[2]."
6. The Bases for each of the TSs revisions are changed accordingly.

The justification to extend the out of service time for the inoperable DGs is based upon a deterministic and risk-informed evaluation.

3.1 Deterministic Evaluation

The licensee stated that this extension of the completion time associated with an inoperable DG is sought to provide needed flexibility in the performance of both corrective maintenance and preventive maintenance (PM) during power operation. Furthermore, the licensee stated that adoption of the proposed extension reduces the risk of unscheduled plant shutdowns. The licensee's desire to perform selected maintenance online is based on the licensee's projection of a number of enhancements to the maintenance process:

- Avert unplanned plant shutdown and minimize the potential for notice of enforcement discretion requests. Risks incurred by unexpected plant shutdowns can be comparable to, and often exceed, those associated with continued power operation.
- Allow increased flexibility in the scheduling and performance of DG PM.
- Allow better control and allocation of resources. Allowing online PM, including overhauls, provides the flexibility to focus more quality resources on any required or elected DG maintenance
- Improve DG availability during shutdown modes or conditions. This will reduce the risk associated with DG maintenance and the synergistic effects on risk due to DG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.
- Permit scheduling of DG overhauls within the requested 14-day completion time period.

According to the licensee, the proposed completion time of 14 days for a DG is adequate to perform normal preventive DG inspections and maintenance requiring disassembly of the DG and to perform post maintenance and operability tests required to return the DG to operable status. The licensee intends that the proposed 14 days completion time for performing a major overhaul of a DG be used at a frequency of no more than once per DG per operating cycle. The licensee states that the time periods to complete unplanned maintenance shall continue to be minimized. The licensee also indicates that plant configuration changes for planned and unplanned maintenance of the DGs, as well as the maintenance of equipment having risk significance, are managed by site procedure.

The licensee's justification for the use of an extended inoperable DG completion time is based upon a risk-informed and deterministic evaluation consisting of three main elements: (1) the availability of the normal and alternate offsite power sources via the startup auxiliary transformers (SATs), (2) verification that the other DGs and offsite power sources are operable, and (3) incorporation of additional requirements in the existing site procedure for configuration risk management while a DG is in an extended completion time. This site procedure is used for DG work as well as other work and helps ensure that there is no significant increase in the risk of or consequences of an event while any DG maintenance is performed.

The offsite power is supplied to the 230 kV and 500 kV switchyards from the transmission network by eight transmission lines, four per high voltage switchyard. The switchyards are

connected by an autotransformer. From the 230 kV switchyard, two electrically and physically separated circuits provide ac power, through SATs 1[2]C and 1[2]D, to 4160 volt ESF buses 1[2]E, 1[2]F, and 1[2]G. SAT 1[2] D provides the normal source of power to the ESF buses 1[2]E, 1[2]F, and 1[2]G. If any 4160 volt ESF bus loses power, an automatic transfer from SAT 1[2]D to SAT 1[2]C occurs. At this time station service 4160 volt buses 1[2]A and 1[2]B supply breakers for SAT 1[2]C also trip open, if closed, disconnecting all nonessential loads from SAT 1[2]C to preclude overloading of the transformer.

SAT 1[2]C and SAT 1[2]D are sized to accommodate the simultaneous starting of all required ESF loads on receipt of an accident signal without the need for load sequencing. However, ESF loads are sequenced when the associated 4160 volt ESF bus is supplied from SAT 1[2]C.

In its letter dated November 15, 2001, the licensee stated that a comprehensive search of Hatch, Unit 1 and Unit 2 Licensee Event Reports (LERs) did not identify any LER that described a loss of offsite power; i.e., the loss of all three 4-kV essential buses. Several LERs described events in which an individual emergency bus was lost; however, in most cases, power was immediately returned to the bus via its alternate source. Others identified the loss of power to non-essential buses and the loss of unit auxiliary transformers.

Hatch has a total of five DGs, one dedicated to each of the 1E, 1G, 2E, and 2G 4160 volt buses and a swing DG that can provide power to either 4160 volt bus 1F or 2F. A DG starts automatically on a LOCA signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus loss of voltage signal. After the DG has started, it automatically ties to its respective bus as a consequence of ESF bus loss of voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the ESF bus on a LOCA signal alone. Following the trip of offsite power, load shed relays strip nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequence timing devices. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a design basis accident (DBA) such as a LOCA.

Due to redundancy of the unit's ESF divisions and DGs, the loss of any one of the DGs will not prevent the safe shutdown of the unit. The total standby power system, including DGs and electrical power distribution equipment, satisfies the single failure criterion.

In order to manage the risk activities associated with the requested completion time extension, the configuration risk management site procedure would be revised. It would be revised to contain the following limitations for plant maintenance of one DG, while in Mode 1, utilizing the completion time extension to 14 days.

- (1) Only one DG of the five DGs for both units will be removed for planned maintenance at a time.
- (2) No planned risk significant activities or maintenance will be performed during the time on either unit when maintenance on 1A (1R43S001A), 1C (1R43S001C), 2A

(2R43S002A), 2C (2R43S002C), or 1B (1R43S001B) DG is in progress. Analog transmitter trip system functional test and calibrations as well as battery charger swapping is allowed.

- (3) Planned DG maintenance will not coincide with planned work in the high voltage switchyard.
- (4) Planned maintenance that will exceed 72 hours on 1A, 1C, 2A, or 2C DG will involve the following requirement.
 - DG 1B will be aligned for supplying emergency power to the 4160 volt F bus of the unit that has a DG in planned maintenance.
 - This alignment will be such that the 1B DG cannot “swing” to the opposite unit on F bus undervoltage or dual unit LOSP with an opposite unit LOCA signal.
 - The intent is to provide two DGs per unit during this time.
 - Forced alignment of the 1B DG will limit alternate low pressure coolant injection (LPCI) bus (1R24S018A, 1R24S018B, 2R24S018A, 2R24S018B) power alignment to the unit assigned the 1B DG.
- (5) The selection or “throwover” switch that determines the alternate source of power for the reactor protection system, 1R25S036 (2R25S036) or 1R25S037 (2R25S037) will be placed accordingly:
 - (a) 1A or 2A DG Maintenance - 1R25S037 or 2R25S037,
 - (b) 1C or 2C DG Maintenance - 1R25S036 or 2R25S036, and
 - (c) 1B DG Maintenance - Either Essential bus.

The licensee stated that TS Section 3.8.1.B.2 accounts for the equipment powered from the 4160 Vac emergency buses that are ultimately backed up by the operable diesels. Failure of this equipment, either by planned maintenance or random events, invokes additional requirements beyond those associated solely with a single DG being out of service. From the standpoint of these existing TS, it is not only unlikely, but impractical, to simultaneously attempt planned maintenance on a DG and equipment whose emergency power source is one of the existing operable DGs.

The licensee further stated that procedure 90AC-OAM-002-0S, “Scheduling Maintenance,” provides for an evaluation of any combination of components that are to be removed from service for maintenance. This procedure is specifically structured to implement the maintenance rule, 10 CFR 50.65. The evaluation is performed using qualitative and quantitative tools based upon a unit-specific probabilistic safety assessment (PSA) risk model. Procedure AG-OAM-002-0701N, which covers work planning, includes the need for pre-job evaluation and preparation. Additionally, procedure DI-MNT49-0796N provides for planning and scheduling personnel affected by the previously referenced procedures to review the actual

maintenance work order used to initiate the maintenance process. This will allow the addition of specific instructions to maintenance foremen and reminders to control room personnel that may be needed when using the proposed additional outage time for the DGs.

Procedure 90AC-OAM-002-0S contains existing limitations on removal from service of certain systems and components in combination with a DG, based on qualitative and quantitative analyses performed for maintenance rule activities. The specific PSA analysis performed for the extended DG outage identified additional structures, systems, and components that are also risk significant if the DG is out of service for the extended time. This equipment is already within the scope of the existing procedure, but the procedure will be modified to specifically identify these systems and components and provide additional restrictions during extended diesel outages.

Procedure 90AC-OAM-002-0S also addresses transients that can be potentially affected by work activities. Additionally, the specific PSA analysis described above identifies 5 transients (i.e., loss of offsite power, loss of condensate, loss of station batteries, loss of 600-V bus C, and loss of plant service water) that are very significant if a DG is out of service for an extended period of time. As a result, additional restrictions will be added to the procedure to address work activities that could increase the likelihood of the 5 transients when a DG is out for an extended period.

Access to and egress from the low voltage switchyard, which contains the startup transformers, main transformers, and unit auxiliary transformers, is controlled as part of the plant protected area. Access to the high voltage switchyard located outside the protected area is keylock controlled. Only operations personnel and selected Georgia Power Company (GPC) Transmission Maintenance and SNC employees have a key; all others requiring access need special consideration. Operation of equipment, such as vehicles or wheeled-cranes, in the low voltage switchyard is not only under security entry/egress control, but is also functionally controlled by procedure. Procedures (AG-MGR-30-0690N and 51GM-MLH-003-0S) govern the operation of this special equipment within the switchyard and address inclement weather operation, the use of ground individuals to aid in maneuvering, and equipment stay time within the area.

The use of SNC employees to operate the special equipment within the high voltage switchyard is addressed in plant procedures. For GPC employees, planning for and operation of equipment is controlled via executive agreement referenced in plant procedure 90AC-OAM-002-0S. Evolutions requiring switchyard maintenance, especially those requiring the use of special equipment, are planned in advance with SNC operations and work planning staff. This procedure identifies which portions of the high voltage switchyard require controls, and defines what "work in the switchyard" means. The procedure already identifies the work in the switchyard, in combination with a DG out of service, that should be avoided. Use of this procedure will continue the avoidance of intentional combination of activities that cause degradation of the offsite electrical supply to the plant in combination with work activities affecting onsite supplies.

In response to a staff concern regarding load rejection testing after the overhaul, the licensee, in its letter dated November 15, 2001, stated that this test is performed after a design modification to the DG speed or voltage controls. The licensee also stated the following:

Normal maintenance or overhaul of the DG does not involve design modification of these controls. If the speed or voltage control components were replaced with different components (not like kind), it would constitute a design change modification and would be subject to load rejection tests as part of post-modification testing. This work would be scheduled during unit outages. Furthermore, the TS specifically prohibits the performance of these surveillances on-line.

Following an on-line overhaul of a DG, the licensee would primarily rely upon the TS semi-annual test (SR 3.8.1.5) to prove DG operability. This test involves starting the DG and verifying that it automatically connects to its emergency bus within 12 seconds. Additionally, the DG would be operated at specified loads for at least 1 hour. This test is routinely performed on-line. Additionally, when the governor is replaced with a similar kind, several speed step changes would be performed (up to rated speed) during the performance runs to confirm proper operation of the governor. These tests, which are immediately followed by a full load fast-start test, are used to confirm operability of the DG after a governor is replaced.

In response to the staff's concern of scheduling extended maintenance of DGs during degraded grid conditions or extreme weather conditions, the licensee stated that an abnormal operating procedure for naturally occurring phenomena (34AB-Y22-0S) prevents and stops the performance of maintenance and surveillance on safety systems under adverse weather conditions or when those conditions are threatening. The procedure prevents maintenance and surveillance on key safety systems, including DGs, when the National Weather Service is forecasting high winds for the site within the next 24 hours. The procedure also provides for confirmation that normal offsite power is available to the essential buses. For hurricane force winds, the procedure provides for a dual unit shutdown at least 2 hours prior to arrival of the high winds on site. The procedure has similar provisions for other natural phenomena such as tornadoes and floods.

Abnormal operating procedure 34AB-S11-001-0S addresses degraded offsite grid conditions. When the offsite system is in jeopardy of not being able to maintain minimum voltage, the Power Coordinator Center will notify the on-shift operations staff. Upon this notification, the procedure provides for returning the inoperable DG to service as soon as possible. The DG maintenance would not be started during this degraded mode. If minimum voltage cannot be maintained, the plant would proceed with an orderly shutdown if the emergency bus voltages cannot be restored to at least minimum voltage within 1 hour.

3.1.2 Conclusion of Deterministic Review

The staff concludes that the licensee's request to increase the DG out-of-service time to 14 days to perform preventive or corrective maintenance is acceptable. The staff's conclusion is based on the following five factors: (1) the availability of two DGs per unit during the extended out-of-service time of a DG; (2) the availability of the normal and alternate offsite power sources via the startup auxiliary transformers; (3) the verification that the other DGs and offsite power sources are operable; (4) there has been no complete LOSP at Hatch since

commercial operation began; and (5) no risk significant equipment will be removed from service for pre-planned maintenance of a DG in accordance with the licensee's program for satisfying 10 CFR 50.65(a)(4). In addition, the staff notes that an abnormal operating procedure prevents DG extended maintenance under adverse weather conditions, or when those conditions are threatening, or when degraded grid conditions exist; and design modifications to a DG speed or voltage controls will not be done on line. Also, the staff finds that the change of the TS Bases section is consistent with the requested DG out of service time extension and is, therefore, acceptable.

3.2 Probabilistic Evaluation

Maintenance associated with LCO allowed outages falls essentially into the two categories of planned (or preventive) maintenance and unplanned maintenance that is comprised of corrective or emergent maintenance. Regulatory Guides (RG) 1.174 "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis" and RG 1.177 "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications" provide licensees with an approach, acceptable to the staff, for assessing the applicability of risk-informed decision making to proposed TS modification, and for managing associated risks. Licensees implementing risk-informed TS changes are expected to manage risk in a manner consistent with this guidance.

3.2.1 Three-Tiered Approach to Assessing Risk

RG 1.177 presents a three-tiered approach to assess risk associated with proposed TS Completion Time (CT) changes. Tier 1 involves an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in core damage frequency (CDF), the incremental conditional core damage probability (ICCDP), and when appropriate, the change in large early release frequency (LERF), and the incremental conditional large early release probability (ICLERP). Tier 2 involves an identification of potentially high-risk configurations that could exist during the CT. Tier 3 involves the implementation of an overall configuration risk management program to ensure that potential configurations resulting from other maintenance or operational activities are identified and that actions are taken to compensate for such configurations.

3.2.2 Minimum Incremental Risk Estimates (Tier 1)

The Hatch PSA has been converted to a linked fault-tree model based on cutset and fault tree analysis (CAFTA) software used to estimate average risks. The original Individual Plant Examination PSA was a Linked Event Tree model constructed with RISKMAN software. The major differences between the two models are in the way success paths and support systems are handled and the physical structure of each model. In the initial conversion, the CDF decreased from 2.0E-05 to 1.6E-05 per year. In going from Rev. 0 to Rev. 1 of the PSA based on CAFTA, the CDF was further reduced to 1.2E-05 per year, with the reduction primarily attributed to an update of the initiating event data using NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995." Instantaneous risks were estimated with an on-line risk monitor, the equipment out-of-service (EOOS) system, using software developed by Data Systems and Solutions for the Electric Power Research Institute. The system

incorporates a no-maintenance model that uses the Hatch PSA to quantify results when analyzing actual (rather than average) plant configurations; it is used in day-to-day risk management at the plant.

The CAFTA PSA model, Rev. 1, has undergone the Probabilistic Risk Assessment Peer Review Process used by the Boiling Water Reactor (BWR) Owner's Group that concluded the PSA can be effectively used to support applications involving absolute risk determinations. While the NRC staff did not review the PSA, the staff asked the licensee to perform various calculations, the results of which lead the staff to agree with the Peer Review Group's overall assessment.

With Rev. 1 of the CAFTA-based PSA model, the licensee estimated the current average CDF and LERF for internal events to be $1.1\text{E-}05$ and $1.4\text{E-}06$ per year, respectively, and the change in the average associated with the proposed TS revision to be $3.0\text{E-}07$ and $1.8\text{E-}07$ per year, respectively. Based on these levels of risk, RG 1.174 indicates the proposed change can be considered on a risk-informed basis.

The licensee performed a qualitative shutdown risk analysis that concluded there was no significant increase in risk associated with performing the DG maintenance at power compared to performing the maintenance during shutdown. The licensee included internal flooding initiators in its PSA and concluded that their contribution to CDF and LERF were negligible. The licensee concluded that the proposed CT extension would not affect the results of its Seismic Margins Analysis since shutdown for the loss of offsite power case is provided by primary and alternate pathways that cover the effect of a single DG being out of service for maintenance. The licensee performed a limited analysis of the impact of the proposed CT extension on fire risks by analyzing fires initiated in the 4160 V AC emergency switchgear rooms causing loss of switchgear and affiliated dc battery systems and concluded that the impact of the CT extension on risk would be small.

With the plant EOOS system, the licensee estimated the minimum risk of operation while an DG is taken out of service for the proposed CT. Due to the similarity of the units, the licensee chose to present results for one unit, Unit 1, as representative of both. The estimated internal events ICCDP and ICLERP for DG C (which due to load asymmetries yields larger values than the others) are $1.2\text{E-}07$ and $6.9\text{E-}08$, respectively. The estimated ICCDP would be within the staff guideline while the estimated ICLERP would be a little higher, but comparable with most BWRs. Additionally, the licensee stated that conservatism in the modeling of the switchyard is sufficiently large to make up the difference between this value and that of the staff guideline.

According to RG 1.177, a Tier 1 assessment is acceptable to the staff if: (1) the PSA used is adequate, (2) PSA insights from analyses of various applicable initiating events are adequate, and (3) internal events estimates of minimum incremental risk probabilities (ICCDP and ICLERP) are within the level of risk the staff considers small for a single CT change. The licensee's assessment was consistent with staff's Tier 1 guidance.

3.2.3 Avoidance of Risk Significant Plant Configurations (Tier 2)

To avoid dominant risk significant plant configurations, the licensee performed an assessment to identify significant risk contributors while the equipment covered by the CT would be out of service. The licensee manages risk with a Scheduling Maintenance Procedure, Administration

Control Procedure 90AC-OAM-002-0S. The procedure is used with the EOOS system to evaluate risk significant configurations and manage maintenance, and is specifically structured to implement the maintenance rule, 10 CFR 50.65. Maintenance activities that affect the availability of risk significant structures and components were identified and the following list of the most risk significant equipment, equipment that should not be out of service during DG maintenance, was developed and will be incorporated into the procedure.

1R24S026, Diesel Generator Motor Control Center
Unit 1 / 2 Core Spray Pumps
Unit 1 / 2 A&C DGs, DG Batteries, Battery Chargers
Unit 1 / 2 Station Service Batteries, Battery Chargers
Unit 1 / 2 Reactor Building Closed Cooling Water Pumps
Unit 1 / 2 600V CD Transformer
Unit 1 / 2 Start up Transformer C & D
Unit 1 / 2 Reactor Protection System MG Sets
Main Control Room (MCR) Air Conditioning Systems
Unit 1 / 2 Station Service Air Compressor Closed Cooling Water Pumps
Unit 1 / 2 LPCI Injection Path Components
MCR Purge Fans A & B
Unit 1 / 2 Control Rod Drive Pumps
Unit 1 / 2 High Pressure Coolant Injection
Unit 1 / 2 Reactor Core Isolation Cooling
Unit 1 / 2 Residual Heat Removal Service Water Pumps and Flow path
Unit 1 / 2 Shutdown Cooling Flow Path
Unit 1 / 2 Suppression Pool Cooling Flow Path
Unit 1 / 2 Plant Service Water Pumps

This list appears reasonable and complete, and the licensee committed to not voluntarily enter a DG LCO with any of the included equipment inoperable. In addition, the risk management procedures will be modified to include the aforementioned limitations listed in Section 3.1 for planned maintenance in Mode 1 on an DG utilizing the CT extension to 14 days.

The licensee's measures to avoid high risk significant plant configurations are consistent with the staff's Tier 2 guidance.

3.2.4 Configuration Risk Management Program (Tier 3)

A configuration risk management program (CRMP) provides a proceduralized risk-informed assessment of the plant in order to manage the risk associated with equipment inoperability. The CRMP should use at least a Level 1, at power, internal events PSA model and is expected to take into consideration qualitative factors that cannot be incorporated into the quantitative model. As noted earlier in this evaluation, licensees typically use the risk management procedures developed for implementation of the maintenance rule to manage risks associated with CT changes. This will be done at Hatch by its Administration Control Procedure, 90AC-OAM-002-0S, mentioned above, that the licensee states meets the intent of RG 1.177.

As input to the procedure, maintenance is normally assessed from a probabilistic standpoint using the EOOS system, the Hatch computerized online risk monitor. There is an EOOS system for each unit. The system uses the actual (level 1 and level 2) PSA model for that unit

to quantify results. The equipment out of service matrix used previously is being phased out as EOOS training and usage progresses. Qualitative assessments are incorporated as needed.

As stated in the procedure, the most fundamental risk management action is planning and sequencing of maintenance activities taking into account the insights provided by the assessment. Other risk management actions include: (1) providing increased risk awareness and control, (2) reducing the duration of the activity, (3) minimizing the risk increase, and (4) obtaining approval of the manager designated as responsible for work at the given level of risk. The risk management procedure, appears adequate for planning maintenance so as to limit risk, which is its primary objective. With regard to multiple equipment outages that may occur in connection with unplanned (corrective or emergent) maintenance, the procedure can help reduce the resulting increase in risk by taking into account the level of risk increase associated with each system or component and their respective required maintenance times to determine the restoration of which inoperable system or component to an operable status will have the largest impact on risk.

According to RG 1.177, a Tier 3 assessment is acceptable if a risk-informed plant configuration control program has been implemented along with procedures to utilize, maintain, and control such a program. The licensee's Scheduling Maintenance procedure, 90AC-OAM-002-0S, is consistent with the staff's Tier 3 guidance.

3.2.5 Conclusion of Probabilistic Review

10 CFR 50.65(a)(4) requires that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

As set forth above, consistent with NRC guidance in RG 1.177, the licensee has provided: (1) minimum incremental risk estimates of ICCDP and ICLERP (i.e., for the case where no other risk significant equipment is out of service) that meet NRC staff guidance for a small change in risk, (2) a list of risk significant equipment that the licensee would keep in service prior to planned DG maintenance, and (3) a description of the Hatch maintenance management procedure that meets the essential characteristics for a CRMP as discussed in RG 1.177. A CRMP (or equivalent procedure) with the characteristics specified in RG 1.177 provides reasonable assurance that the licensee can acceptably control maintenance, planned and unplanned. Therefore, the licensee's proposed amendments are acceptable.

4.0 STATE CONSULTATION

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

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve 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 amendments involve no significant hazards consideration, and there has been no public comment on such finding (66 FR 52803). Accordingly, the amendments meet 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 amendments.

6.0 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

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