August 31, 1995

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Mr. J. T. Beckham, Jr.
Vice President - Plant Hatch
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

SUBJECT: ISSUANCE OF AMENDMENTS - EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2 (TAC NOS.

Dear Mr. Beckham:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 197 to Facility Operating License DPR-57 and Amendment No. 138 to 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 January 13, 1995, as supplemented by letters dated April 5 and June 20, 1995.

The amendments modify Facility Operating License Nos. DRP-57 and NPF-5 and the corresponding TS for Hatch Units 1 and 2, respectively, to authorize an increase in the maximum power level from 2436 megawatts thermal (MWt) to 2558 MWt. The amendments also approve changes to the TS to implement uprated power operation.

The amendments are effective as of their date of issuance and are to be implemented prior to the startup in Cycle 17 for Unit 1 and prior to the startup in Cycle 13 for Unit 2.

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,
Original signed by:
Kahtan N. Jabbour, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-321 and 50-366

Enclosures:
1. Amendment No. 197 to DPR-57
2. Amendment No. 138 to NPF-5
3. Safety Evaluation

cc w/encl: See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 31, 1995

Mr. J. T. Beckham, Jr.
Vice President - Plant Hatch
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

SUBJECT: ISSUANCE OF AMENDMENTS - EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2 (TAC NOS. M91077 and M91078)

Dear Mr. Beckham:

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The amendments modify Facility Operating License Nos. DRP-57 and NPF-5 and the corresponding TS for Hatch Units 1 and 2, respectively, to authorize an increase in the maximum power level from 2436 megawatts thermal (MWt) to 2558 MWt. The amendments also approve changes to the TS to implement uprated power operation.

The amendments are effective as of their date of issuance and are to be implemented prior to the startup in Cycle 17 for Unit 1 and prior to the startup in Cycle 13 for Unit 2.

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

Sincerely,

Kahtan N. Jabbour

Kahtan N. Jabbour, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
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1. Amendment No. 197 to DPR-57
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3. Safety Evaluation

cc w/encl: See next page

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Georgia Power Company

Edwin I. Hatch Nuclear Plant

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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 FACILITY OPERATING LICENSE

Amendment No. 197
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) Facility Operating License No. DPR-57 filed by the Georgia Power Company, acting for itself, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the licensees), dated January 13, 1995, as supplemented by letters dated Arpil 5 and June 20, 1995, 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 paragraphs 2.C.(1) and 2.C.(2) of Facility Operating License No. DPR-57 are hereby amended to read as follows:

   (1) <u>Maximum Power Level</u>

   The Georgia Power Company is authorized to operate the facility at steady state reactor core power levels not in excess of 2558 megawatts thermal.

   (2) <u>Technical Specifications</u>

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

3. This license amendment is effective as of its date of issuance and shall be implemented prior to startup in Cycle 17.

FOR THE NUCLEAR REGULATORY COMMISSION

WTRussell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachment:
1. Technical Specification Changes
2. License Changes

Date of Issuance: August 31, 1995

ATTACHMENT TO LICENSE AMENDMENT NO. 197

FACILITY OPERATING LICENSE NO. DPR-57

DOCKET NO. 50-321

Replace the following pages of the Appendix "A" Technical Specifications and Bases with the enclosed pages. The revised pages are identified by Amendment number and contain vertical lines indicating the areas of change. Also replace the following page of the Operating License (OL).

Remove Pages	Insert Pages
1.1-5	1.1-5
3.1-23	3.1-23
3.3-7	3.3-7
3.3-32	3.3-32
3.3-66	3.3-66
3.4-4	3.4-4
3.4-8	3.4-8
3.4-28	3.4-28
3.5-5	3.5-5
3.5-12	3.5-12
B 3.1-44	B 3.1-44
B 3.3-154	B 3.3-154
B 3.3-159	B 3.3-159
B 3.4-4	B 3.4-4
B 3.4-53	B 3.4-53
B 3.4-54	B 3.4-54
B 3.5-3	B 3.5-3
B 3.5-23	B 3.5-23
B 3.6-2	B 3.6-2
B 3.6-7	B 3.6-7
B 3.6-28	B 3.6-28
B 3.7-33	B 3.7-33
B 3.10-1	B 3.10-1
Page 3 (OL)	Page 3 (OL)

(2) Pursuant to the Act and 10 CFR Part 70, Georgia Power Company to receive, possess and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70 Georgia Power Company to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, Georgia Power Company to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, Georgia Power Company to posses, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50-54 and 50-59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) <u>Maximum Power Level</u>

The Georgia Power Company is authorized to operate the facility at steady state reactor core power levels not in excess of 2558 megawatts thermal.

1.1 Definitions (continued)

PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Section 13.6, Startup and Power Test Program, of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2558 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.5	Verify the concentration of sodium pentaborate in solution is within the Region A limits of Figure 3.1.7-1.	31 days AND Once within 24 hours after water or sodium pentaborate is added to solution AND Once within 24 hours after solution temperature is restored within the Region A limits of Figure 3.1.7-2
SR 3.1.7.6	Verify each SLC subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position, or can be aligned to the correct position.	31 days
SR 3.1.7.7	Verify each pump develops a flow rate $\geq$ 41.2 gpm at a discharge pressure $\geq$ 1201 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	18 months on a STAGGERED TEST BASIS

(continued)

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Fixed Neutron Flux – High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 120% RTP
d. Downscale	1	2	F	SR 3.3.1.1.5 SR 3.3.1.1.8 SR 3.3.1.1.15	≥ 4.2% RTP
e. Inop	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.15	NA
3. Reactor Vessel Steam Dome Pressure – High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1085 psig
4. Reactor Vessel Water Level – Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≥ 0 inches
5. Main Steam Isolation Valve – Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 10% closed
6. Drywell Pressure – High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1.92 psig

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level — ATWS-RPT Level: ≥ -73 inches; and b. Reactor Steam Dome Pressure — High: ≤ 1175 psig.	18 months
SR 3.3.4.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	18 months

Table 3.3.6.3-1 (page 1 of 1)
Low-Low Set Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Steam Dome Pressure — High	1 per LLS valve	SR 3.3.6.3.1 SR 3.3.6.3.4 SR 3.3.6.3.5 SR 3.3.6.3.6	≤ 1085 psig
2. Low-Low Set Pressure Setpoints	2 per LLS valve	SR 3.3.6.3.1 SR 3.3.6.3.4 SR 3.3.6.3.5 SR 3.3.6.3.6	Low: Open ≤ 1005 psig Close ≤ 857 psig Medium-Low: Open ≤ 1020 psig Close ≤ 872 psig Medium-High: Open ≤ 1035 psig Close ≤ 887 psig High: Open ≤ 1045 psig Close ≤ 897 psig
3. Tailpipe Pressure Switch	2 per S/RV	SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.5 SR 3.3.6.3.6	≥ 80 psig and ≤ 100 psig

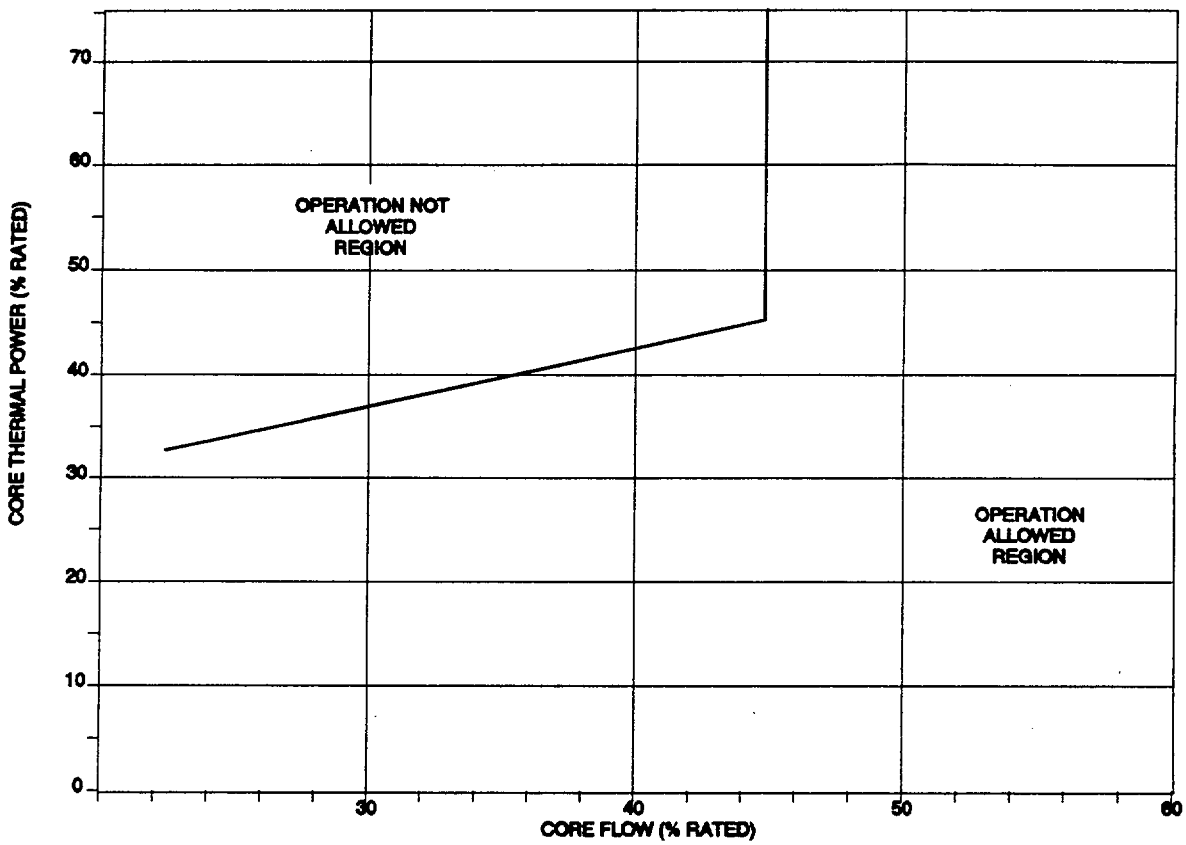

Figure 3.4.1-1 (Page 1 of 1)
Power-Flow Operating Map with One Reactor
Coolant System Recirculation Loop in Operation

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the S/RVs are as follows: Number of S/RVs — Setpoint (psig) 4 — 1110 ± 33.3 4 — 1120 ± 33.6 3 — 1130 ± 33.9 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	-------------------NOTE-------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each S/RV opens when manually actuated.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1058 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.10.1 Verify reactor steam dome pressure is ≤ 1058 psig.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.6	-------------------NOTE------------------- Only required to be performed prior to entering MODE 2 from MODE 3 or 4, when in MODE 4 > 48 hours. -- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	 31 days
SR 3.5.1.7	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS / ≥ 4250 gpm / 1 / ≥ 113 psig LPCI / ≥ 17,000 gpm / 2 / ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.8	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 1058 psig and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	 92 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.3.2	Verify each RCIC System manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.3.3	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 1058 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	92 days
SR 3.5.3.4	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 165 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	18 months

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.4 and SR 3.1.7.6 (continued)

in the nonaccident position provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance also does not apply to valves that are locked, sealed, or otherwise secured in position since they are verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensures correct valve positions.

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of boron exists in the storage tank (within Region A limits of Figures 3.1.7-1 and 3.1.7-2). SR 3.1.7.5 must be performed anytime sodium pentaborate or water is added to the storage tank solution to determine that the boron solution concentration is within the specified limits. SR 3.1.7.5 must also be performed any time the temperature is restored to within the Region A limits of Figure 3.1.7-2, to ensure that no significant boron precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances.

SR 3.1.7.7

Demonstrating that each SLC System pump develops a flow rate $\geq$ 41.2 gpm at a discharge pressure $\geq$ 1201 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow — High (continued)

detect the high flow. Four channels of Main Steam Line Flow — High Function for each unisolated MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break. The Allowable Value corresponds to ≤ 116 psid, which is the parameter monitored on control room instruments.

This Function isolates the Group 1 valves.

1.d. Condenser Vacuum — Low

The Condenser Vacuum — Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Vacuum — Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all turbine stop valves (TSVs) are closed, since the potential for condenser

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a., 4.a. HPCI and RCIC Steam Line Flow — High (continued)

recirculation and MSL breaks. However, these instruments prevent the RCIC or HPCI steam line breaks from becoming bounding.

The HPCI and RCIC Steam Line Flow — High signals are initiated from transmitters (two for HPCI and two for RCIC) that are connected to the system steam lines. Two channels of both HPCI and RCIC Steam Line Flow — High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event. The Allowable Values correspond to ≤ 228 inches water column for HPCI and ≤ 209 inches water column for RCIC, which are the parameters monitored on control room instruments.

These Functions isolate the Group 3 and 4 valves, as appropriate.

3.b., 4.b. HPCI and RCIC Steam Supply Line Pressure — Low

Low MSL pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the FSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations. Therefore, they meet Criterion 4 of the NRC Policy Statement (Ref. 6).

The HPCI and RCIC Steam Supply Line Pressure — Low signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure — Low Functions are available and are required to

(continued)

BASES

LCO (continued)

and APRM Flow Biased Simulated Thermal Power — High setpoint (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of Reference 3. In addition, core flow as a function of core thermal power must be in the "Operation Allowed Region" of Figure 3.4.1-1 to ensure core thermal-hydraulic oscillations do not occur.

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1 and B.1

Due to thermal-hydraulic stability concerns, operation of the plant with one recirculation loop is controlled by restricting the core flow to ≥ 45% of rated core flow when THERMAL POWER is greater than the 76% rod line. This requirement is based on the recommendations contained in GE SIL-380, Revision 1 (Reference 4), which defines the region where the limit cycle oscillations are more likely to occur. If the core flow as a function of core thermal power is in the "Operation Not Allowed Region" of Figure 3.4.1-1, prompt action should be initiated to restore the flow-power combination to within the Operation Allowed Region. The 2 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing core oscillations to be quickly detected. An immediate reactor scram is also required with no recirculation pumps in operation, since all forced circulation has been lost and the probability of thermal-hydraulic oscillations is greater.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of design basis accidents and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1058 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement (Ref. 3).
LCO	The specified reactor steam dome pressure limit of ≤ 1058 psig ensures the plant is operated within the assumptions of the overpressure protection analysis. Operation above the limit may result in a response more severe than analyzed.
APPLICABILITY	In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these

(continued)

BASES

APPLICABILITY (continued)	MODES, the reactor may be generating significant steam and events which may challenge the overpressure limits are possible. In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.
ACTIONS	<u>A.1</u> With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized. <u>B.1</u> If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.4.10.1</u> Verification that reactor steam dome pressure is ≤ 1058 psig ensures that the initial conditions of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES

BACKGROUND (continued)

pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling." Two LPCI inverters (one per subsystem) are designed to provide the power to various LPCI subsystem valves (e.g., inboard injection valves). This will ensure that a postulated worst case single active component failure, during a design basis loss of coolant accident (which includes loss of offsite power), would not result in the low pressure ECCS subsystems failing to meet their design function. (While an alternate power supply is available, the low pressure ECCS subsystems may not be capable of meeting their design function if the alternate power supply is in service.)

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1154 psig). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from a main steam line upstream of the associated inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1154 psig). Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 1.2% by weight of the containment air per 24 hours at the maximum peak containment pressure (P_a) of 49.6 psig (Ref. 1).

Primary containment satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to less than L_a, except prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test. At this time, the combined Type B and C leakage must be < 0.6 L_a, and the overall Type A leakage must be < 0.75 L_a. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

(continued)

BASES

BACKGROUND (continued)	containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.2% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 49.6 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).
LCO	As part of primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The drywell pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial drywell pressure of 1.75 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the maximum allowable of 62 psig. The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is 49.6 psig (Ref. 1). Drywell pressure satisfies Criterion 2 of the NRC Policy Statement (Ref. 2).
LCO	In the event of a DBA, with an initial drywell pressure $\leq$ 1.75 psig, the resultant peak drywell accident pressure will be maintained below the drywell design pressure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.

(continued)

BASES

LCO (continued)

with this requirement (2436 MWt x 100 μCi/MWt-second = 240 mCi/second). The 240 mCi/second limit is conservative for a rated core thermal power of 2558 MWt.

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment, the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in the drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The

(continued)

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 212°F (normally corresponding to MODE 3).

System hydrostatic testing and system leakage (same as inservice leakage tests) pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Inservice system leakage tests are performed at the end of each refueling outage with the system set for normal power operation. Some parts of the Class 1 boundary are not pressurized during these system tests. System hydrostatic tests are required once per interval and include all the Class 1 boundary unless the test is broken into smaller portions. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. The hydrostatic test requires increasing pressure to approximately 1139 psig. The system leakage test requires increasing pressure to approximately 1035 psig.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RCS P/T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel.

(continued)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

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 FACILITY OPERATING LICENSE

Amendment No. 138
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) Facility Operating License No. NPF-5 filed by the Georgia Power Company, acting for itself, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the licensees), dated January 13, 1995, as supplemented by letters dated April 5 and June 20, 1995, 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 paragraphs 2. C.(1) and 2.C.(2) of Facility Operating License No. NPF-5 are hereby amended to read as follows:

    (1) Maximum Power Level

    The Georgia Power Company is authorized to operate the facility at steady state reactor core power levels not in excess of 2558 megawatts thermal.

    (2) Technical Specifications

    The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 138 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to startup in Cycle 13.

FOR THE NUCLEAR REGULATORY COMMISSION

W. Russell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachment:
1. Technical Specification Changes
2. License Changes

Date of Issuance: August 31, 1995

ATTACHMENT TO LICENSE AMENDMENT NO. 138

FACILITY OPERATING LICENSE NO. NPF-5

DOCKET NO. 50-366

Replace the following pages of the Appendix "A" Technical Specifications and Bases with the enclosed pages. The revised pages are identified by Amendment number and contain vertical lines indicating the areas of change. Also replace the following page of the Operating License (OL).

Remove Pages	Insert Pages
1.1-5	1.1-5
3.1-23	3.1-23
3.3-8	3.3-8
3.3-33	3.3-33
3.3-67	3.3-67
3.4-4	3.4-4
3.4-8	3.4-8
3.4-28	3.4-28
3.5-5	3.5-5
3.5-12	3.5-12
B 3.1-44	B 3.1-44
B 3.3-154	B 3.3-154
B 3.3-159	B 3.3-159
B 3.4-4	B 3.4-4
B 3.4-53	B 3.4-53
B 3.4-54	B 3.4-54
B 3.5-3	B 3.5-3
B 3.5-23	B 3.5-23
B 3.6-2	B 3.6-2
B 3.6-7	B 3.6-7
B 3.6-29	B 3.6-29
B 3.7-33	B 3.7-33
B 3.10-1	B 3.10-1
Page 4 (OL)	Page 4 (OL)

(1) Maximum Power Level

Georgia Power Company is authorized to operate the facility at steady state reactor core power levels not in excess of 2558 megawatts thermal in accordance with the conditions specified herein and in Attachment 2 to this license. Attachment 2 is an integral part of this license.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 138 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

The Surveillance Requirements (SRs) contained in the Appendix A Technical Specifications and listed below are not required to be performed immediately upon implementation of Amendment No. 135. The SRs listed below shall be successfully demonstrated prior to the time and condition specified below for each:

a) SRs 3.3.2.2.2, 3.3.2.2.3, 3.3.3.2.2, 3.3.8.1.4, 3.6.2.4.2, 3.7.7.2, and 3.7.7.3 shall be successfully demonstrated prior to entering MODE 2 on the first plant startup following the twelfth refueling outage;

b) SRs 3.8.1.8, 3.8.1.9 (for DG 2C), 3.8.1.10, 3.8.1.12, 3.8.1.13, 3.8.1.17 (for DG 2C), and 3.8.1.18 shall be successfully demonstrated at their next regularly scheduled performance;

c) SRs 3.6.4.1.3 and 3.6.4.1.4 will be met at implementation for the second containment configuration in effect at that time. The SRs shall be successfully demonstrated for the other secondary containment configurations prior to the plant entering the LCO applicability for that configuration.

1.1 Definitions

MINIMUM CRITICAL POWER RATIO (MCPR) (continued)	appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE — OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, Initial Tests and Operation, of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2558 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.5	Verify the concentration of sodium pentaborate in solution is within the Region A limits of Figure 3.1.7-1.	31 days AND Once within 24 hours after water or sodium pentaborate is added to solution AND Once within 24 hours after solution temperature is restored within the Region A limits of Figure 3.1.7-2
SR 3.1.7.6	Verify each SLC subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position, or can be aligned to the correct position.	31 days
SR 3.1.7.7	Verify each pump develops a flow rate $\geq$ 41.2 gpm at a discharge pressure $\geq$ 1201 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	18 months on a STAGGERED TEST BASIS

(continued)

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Fixed Neutron Flux - High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15 SR 3.3.1.1.16	≤ 120% RTP
d. Downscale	1	2	F	SR 3.3.1.1.5 SR 3.3.1.1.8 SR 3.3.1.1.15	≥ 4.2% RTP
e. Inop	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.15	NA
3. Reactor Vessel Steam Dome Pressure - High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16	≤ 1085 psig
4. Reactor Vessel Water Level - Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16	≥ 0 inches
5. Main Steam Isolation Valve - Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16	≤ 10% closed
6. Drywell Pressure - High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1.92 psig

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level — ATWS-RPT Level: ≥ -73 inches; and b. Reactor Steam Dome Pressure — High: ≤ 1175 psig.	18 months
SR 3.3.4.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	18 months

Table 3.3.6.3-1 (page 1 of 1)
Low-Low Set Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Steam Dome Pressure — High	1 per LLS valve	SR 3.3.6.3.1 SR 3.3.6.3.4 SR 3.3.6.3.5 SR 3.3.6.3.6	≤ 1085 psig
2. Low-Low Set Pressure Setpoints	2 per LLS valve	SR 3.3.6.3.1 SR 3.3.6.3.4 SR 3.3.6.3.5 SR 3.3.6.3.6	Low: Open ≤ 1010 psig Close ≤ 860 psig Medium-Low: Open ≤ 1025 psig Close ≤ 875 psig Medium-High: Open ≤ 1040 psig Close ≤ 890 psig High: Open ≤ 1050 psig Close ≤ 900 psig
3. Tailpipe Pressure Switch	2 per S/RV	SR 3.3.6.3.2 SR 3.3.6.3.3 SR 3.3.6.3.5 SR 3.3.6.3.6	≥ 80 psig and ≤ 100 psig

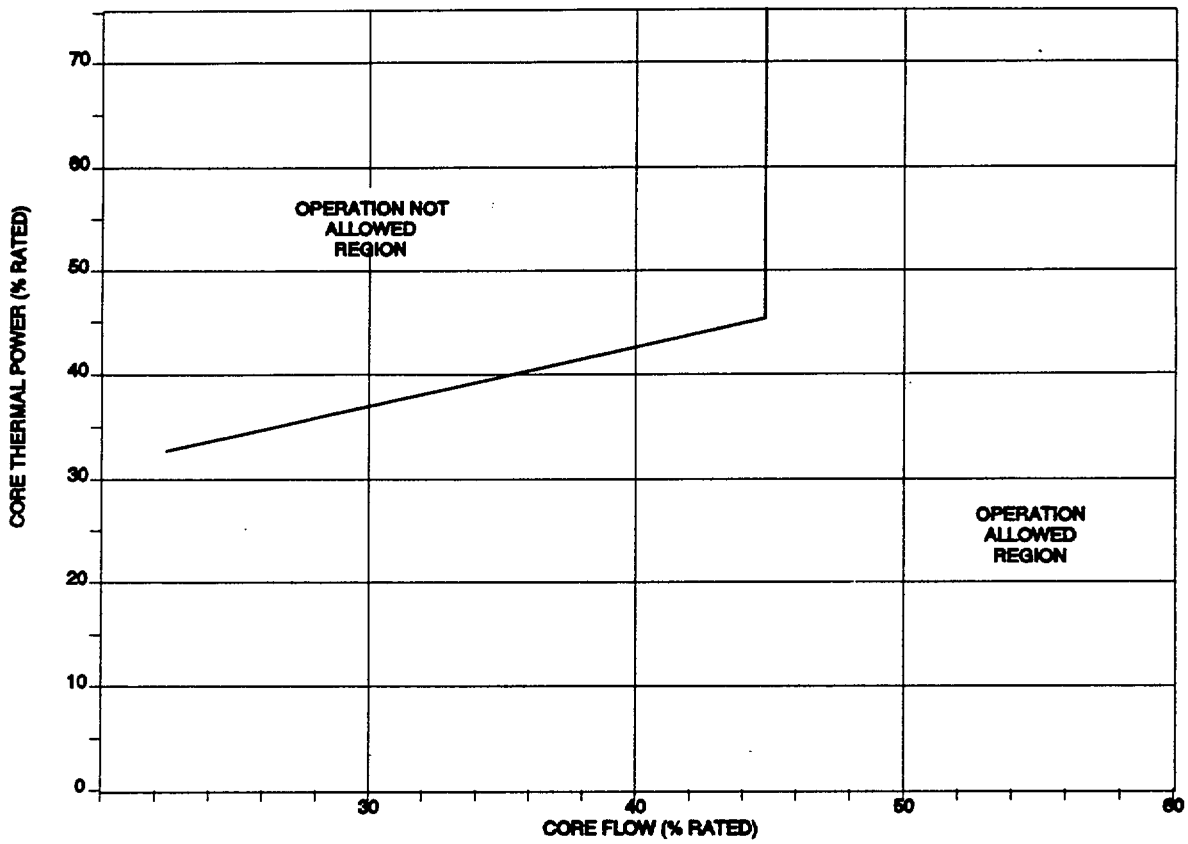

Figure 3.4.1-1 (Page 1 of 1)
Power-Flow Operating Map with One Reactor
Coolant System Recirculation Loop in Operation

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the S/RVs are as follows: Number of S/RVs — Setpoint (psig) 4 — 1120 ± 33.6 4 — 1130 ± 33.9 3 — 1140 ± 34.2 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each S/RV opens when manually actuated.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1020 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.10.1 Verify reactor steam dome pressure is ≤ 1058 psig.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.5.1.6	-------------------NOTE------------------- Only required to be performed prior to entering MODE 2 from MODE 3 or 4, when in MODE 4 > 48 hours. -- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	31 days
SR 3.5.1.7	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS / ≥ 4250 gpm / 1 / ≥ 113 psig LPCI / ≥ 17,000 gpm / 2 / ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.8	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 1058 psig and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	92 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.3.2	Verify each RCIC System manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.3.3	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 1058 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	92 days
SR 3.5.3.4	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 165 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	18 months

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.4 and SR 3.1.7.6 (continued)

in the nonaccident position provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance also does not apply to valves that are locked, sealed, or otherwise secured in position since they are verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensures correct valve positions.

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of boron exists in the storage tank (within Region A limits of Figures 3.1.7-1 and 3.1.7-2). SR 3.1.7.5 must be performed anytime sodium pentaborate or water is added to the storage tank solution to determine that the boron solution concentration is within the specified limits. SR 3.1.7.5 must also be performed any time the temperature is restored to within the Region A limits of Figure 3.1.7-2, to ensure that no significant boron precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances.

SR 3.1.7.7

Demonstrating that each SLC System pump develops a flow rate $\geq$ 41.2 gpm at a discharge pressure $\geq$ 1201 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow — High (continued)

detect the high flow. Four channels of Main Steam Line Flow — High Function for each unisolated MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break. The Allowable Value corresponds to ≤ 145 psid, which is the parameter monitored on control room instruments.

This Function isolates the Group 1 valves.

1.d. Condenser Vacuum — Low

The Condenser Vacuum — Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Vacuum — Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum — Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all turbine stop valves (TSVs) are closed, since the potential for condenser

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a., 4.a. HPCI and RCIC Steam Line Flow — High (continued)

recirculation and MSL breaks. However, these instruments prevent the RCIC or HPCI steam line breaks from becoming bounding.

The HPCI and RCIC Steam Line Flow — High signals are initiated from transmitters (two for HPCI and two for RCIC) that are connected to the system steam lines. Two channels of both HPCI and RCIC Steam Line Flow — High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event. The Allowable Values correspond to ≤ 212 inches water column for HPCI and ≤ 153 inches water column for RCIC, which are the parameters monitored on control room instruments.

These Functions isolate the Group 3 and 4 valves, as appropriate.

3.b., 4.b. HPCI and RCIC Steam Supply Line Pressure — Low

Low MSL pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the FSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations. Therefore, they meet Criterion 4 of the NRC Policy Statement (Ref. 7).

The HPCI and RCIC Steam Supply Line Pressure — Low signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure — Low Functions are available and are required to

(continued)

BASES

LCO (continued)

and APRM Flow Biased Simulated Thermal Power — High setpoint (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of Reference 3. In addition, core flow as a function of core thermal power must be in the "Operation Allowed Region" of Figure 3.4.1-1 to ensure core thermal-hydraulic oscillations do not occur.

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1 and B.1

Due to thermal-hydraulic stability concerns, operation of the plant with one recirculation loop is controlled by restricting the core flow to ≥ 45% of rated core flow when THERMAL POWER is greater than the 76% rod line. This requirement is based on the recommendations contained in GE SIL-380, Revision 1 (Reference 4), which defines the region where the limit cycle oscillations are more likely to occur. If the core flow as a function of core thermal power is in the "Operation Not Allowed Region" of Figure 3.4.1-1, prompt action should be initiated to restore the flow-power combination to within the Operation Allowed Region. The 2 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing core oscillations to be quickly detected. An immediate reactor scram is also required with no recirculation pumps in operation, since all forced circulation has been lost and the probability of thermal-hydraulic oscillations is greater.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of design basis accidents and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1058 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement (Ref. 3).
LCO	The specified reactor steam dome pressure limit of ≤ 1058 psig ensures the plant is operated within the assumptions of the overpressure protection analysis. Operation above the limit may result in a response more severe than analyzed.
APPLICABILITY	In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these

(continued)

BASES

APPLICABILITY (continued)

MODES, the reactor may be generating significant steam and events which may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1058 psig ensures that the initial conditions of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES

BACKGROUND (continued)

pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling." Two LPCI inverters (one per subsystem) are designed to provide the power to various LPCI subsystem valves (e.g., inboard injection valves). This will ensure that a postulated worst case single active component failure, during a design basis loss of coolant accident (which includes loss of offsite power), would not result in the low pressure ECCS subsystems failing to meet their design function. (While an alternate power supply is available, the low pressure ECCS subsystems may not be capable of meeting their design function if the alternate power supply is in service.)

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (162 psid to 1169 psid, vessel to pump suction). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from a main steam line upstream of the associated inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1154 psig). Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 1.2% by weight of the containment air per 24 hours at the maximum peak containment pressure (P_a) of 45.5 psig (Ref. 1).

Primary containment satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to less than L_a, except prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test. At this time, the combined Type B and C leakage must be < 0.6 L_a, and the overall Type A leakage must be < 0.75 L_a. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

(continued)

BASES

BACKGROUND (continued)	containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.2% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 45.5 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).
LCO	As part of primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The drywell pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial drywell pressure of 1.75 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the maximum allowable of 62 psig. The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is 45.5 psig (Ref. 1). Drywell pressure satisfies Criterion 2 of the NRC Policy Statement (Ref. 2).
LCO	In the event of a DBA, with an initial drywell pressure $\leq$ 1.75 psig, the resultant peak drywell accident pressure will be maintained below the drywell design pressure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.

(continued)

BASES

LCO (continued)

with this requirement (2436 MWt x 100 μCi/MWt-second = 240 mCi/second). The 240 mCi/second limit is conservative for a rated core thermal power of 2558 MWt.

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment, the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in the drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The

(continued)

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 212°F (normally corresponding to MODE 3).

System hydrostatic testing and system leakage (same as inservice leakage tests) pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Inservice system leakage tests are performed at the end of each refueling outage with the system set for normal power operation. Some parts of the Class 1 boundary are not pressurized during these system tests. System hydrostatic tests are required once per interval and include all the Class 1 boundary unless the test is broken into smaller portions. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. The hydrostatic test requires increasing pressure to approximately 1139 psig. The system leakage test requires increasing pressure to approximately 1035 psig.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RCS P/T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel.

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 197 TO FACILITY OPERATING LICENSE DPR-57

AND AMENDMENT NO. 138 TO FACILITY OPERATING LICENSE NPF-5

GEORGIA POWER COMPANY, ET AL.

EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-321 AND 50-366

1.0 INTRODUCTION

By letter dated January 13, 1995, as supplemented by letters dated April 5, and June 20, 1995 (Reference 1), Georgia Power Company, et al. (the licensee or GPC), submitted proposed changes to Facility Operating License Nos. DPR-57 and NPF-5 and the Technical Specifications (TS) for the Edwin I. Hatch Nuclear Plant (Hatch), Units 1 and 2. The proposed changes would uprate the licensed thermal power level for each unit from the current level of 2436 megawatts thermal (MWt) to 2558 MWt.

2.0 BACKGROUND

On December 28, 1990, General Electric Company (GE) submitted GE Licensing Topical Report (LTR) NEDC-31897P-A (Reference 2), in which it proposed to create a generic program to increase the rated thermal power levels of BWR/4, BWR/5, and BWR/6 product lines by approximately 5%. The report contained a proposed outline for individual license amendment submittals and discussed the scope and depth of reviews needed and methodologies used in these reviews. In a letter dated September 30, 1991 (Reference 3), the NRC staff approved the program proposed in the GE report on the condition that individual power uprate amendment requests meet certain requirements contained in the staff's approval document .

The generic BWR power uprate program gives each licensee a consistent means to recover additional generating capacity beyond its current licensed limit; up to the reactor power level used in the original design of the nuclear steam supply system (NSSS). The original licensed power level for most licensees was based on the vendor-guaranteed power level for the reactor. The difference between the guaranteed power level and the design power level is often referred to as stretch power. The design power level is used in determining the specifications for all major NSSS equipment, including the emergency core cooling systems (ECCS). Therefore, increasing the rated thermal power does not violate the design parameters of the NSSS equipment and does not significantly affect the reliability of this equipment.

The licensee's request to uprate the current licensed power level from 2436 MWt to a new limit of 2558 MWt represents approximately a 5% increase in thermal power with a corresponding 6% increase in rated steam flow. The planned approach to achieve the higher power level consists of: (1) an increase in the core thermal power utilizing a flatter power distribution to create an increased steam flow, (2) a corresponding increase in feedwater flow, (3) no increase in maximum core flow, (4) a small increase in reactor operating pressure (approximately 3%), and (5) reactor operation primarily along equivalent rod/flow control lines. This approach is consistent with the BWR generic power uprate guidelines presented in Reference 2. The generic analyses and evaluations in NEDC-31984P and Supplements 1 and 2 to this report (Reference 4) are based on a slightly smaller increase (4.2% vs. 5.0%) than is requested for the Hatch units. The operating pressure will be increased approximately 30 psi to assure satisfactory pressure control and pressure drop characteristics for the increased steam flow.

3.0 EVALUATION

The NRC staff reviewed the licensee's request for the Hatch, Units 1 and 2, power uprate amendments, using applicable rules, regulatory guides, and sections of the Standard Review Plan (NUREG-0800), and NRC staff positions. The NRC staff also evaluated the licensee's submittal (Reference 1) for compliance with the generic BWR power uprate program contained in Reference 2. Individual review topics that comprise the staff's evaluation of this power uprate are discussed in detail below.

3.1 Fuel Design and Operation

All fuel and core design limits will continue to be met by control rod pattern and/or core flow adjustments. Current design methods will not be changed for power uprate. Power uprate will increase the core power density, and will have some effects on operating flexibility, reactivity characteristics, and energy requirements.

3.1.1 Thermal Limits Assessment

Operating limits are established to assure regulatory and/or safety limits are not exceeded for a range of postulated events as is currently the practice. The operating limit and safety limit minimum critical power ratio (MCPR) as well as the maximum average planar linear heat generation rate (MAPLHGR) and linear heat generation rate (LHGR) limits are cycle-specific and as such will be established at each reload as is described in Reference 4.

3.1.2 Power/Flow Operating Map

The uprated power/flow operating map includes the operating domain changes for uprated power. The map includes the increased core flow (ICF) range and an uprated Extended Load Line Limit (ELLL). The maximum thermal operating power and maximum core flow correspond to the uprated power and the maximum core flow for ICF. Power has been rescaled so that uprated power is equal to 100% rated power.

3.1.3 Stability

Ongoing activities by the BWR Owners' Group and the NRC are addressing ways to minimize the occurrence and potential effects of power oscillations that have been observed for certain BWR operating conditions (as required by General Design Criteria 12 of 10 CFR Part 50 Appendix A). GE has documented information and cautions concerning this possibility in Service Information Letter (SIL) 380 and related communications. The NRC has documented its concerns in NRC Bulletin No. 88-07 and Supplement 1 to that Bulletin. While a more permanent resolution is being developed, Technical Specifications and associated implementing procedures, as requested by the NRC Bulletin, have been incorporated by the licensee that restrict plant operation in the high power, low core flow region of the BWR power/flow operating map. Specific operator actions have been established to provide clear instructions for the possibility that a reactor inadvertently (or under controlled conditions) enters any of the defined regions.

The restrictions recommended by NRC Bulletin 88-07 and Supplement 1 to the Bulletin will continue to be followed by the licensee for uprated operation. Final resolution will continue to proceed as directed by the joint effort of the BWR Owners' Group and the NRC. The NRC staff concludes that this is acceptable.

3.1.4 Reactivity Control

3.1.4.1 Control Rod Drives (CRD) and CRD Hydraulic System

The CRD system controls gross changes in core reactivity by positioning neutron absorbing control rods within the reactor. It is also required to scram the reactor by rapidly inserting withdrawn rods into the core. The CRD system was evaluated at the uprated steam flow and dome pressure.

The increase in dome pressure due to power uprate produces a corresponding increase in the bottom head pressure. Initially, rod insertion will be slower due to the high pressure. As the scram continues, the reactor pressure will eventually become the primary source of pressure to complete the scram. The higher reactor pressure will improve scram performance after the initial degradation. Therefore, an increase in the reactor pressure has little effect on scram time. The licensee has indicated that CRD performance during power uprate will meet current TS requirements. The licensee will continue to monitor by various surveillance requirements the scram time performance as required in the plant TS to ensure that the original licensing basis for the scram system is preserved.

For CRD insertion and withdrawal, the required minimum differential pressure between the hydraulic control unit (HCU) and the vessel bottom head is 250 psi. The CRD pumps were evaluated against this requirement and were found to have sufficient capacity. The flows required for CRD cooling and driving are assured by automatic opening of the system control valve, thus compensating for the small increase in pressure. The licensee stated that the flow control valve will be adjusted, as needed, to continue to work within the optimum operating range. If testing determines that the adequate cooling and drive flow may not be available under uprate conditions, the pumps and/or flow control valves will be refurbished or replaced assuring that the CRD system will continue to carry out its functions at uprated conditions. The CRD system will therefore continue to perform all its safety-related functions at uprated power, and will function adequately during insert and withdraw modes. The NRC staff has evaluated this commitment by the licensee and concluded that it is acceptable.

3.2 Reactor Coolant System and Connected Systems

3.2.1 Nuclear System Pressure Relief

The nuclear boiler pressure relief system prevents overpressurization of the nuclear system during abnormal operating transients. The plant safety/relief valves (SRVs) with reactor scram provide this protection. For the power uprate, the analytical limits for the relief function of the SRV setpoints have been increased by 30 psi.

The operating steam dome pressure is selected to achieve good control characteristics for the turbine control valves (TCVs) at the higher steam flow condition corresponding to uprated power. The uprate dome pressure increase will require a change in the SRV setpoints. The appropriate increase in the SRV setpoints also ensures that adequate differences between operating pressure and setpoints are maintained (e.g., the "simmer margin"), and that the increase in steam dome pressure does not result in an increase in the number of unnecessary SRV actuations.

3.2.2 Code Overpressure Protection

The results of the overpressure protection analysis are contained in each cycle-specific reload amendment submittal. The design pressure of the reactor pressure vessel (RPV) remains at 1250 psig. The ASME Code allowable peak pressure for the reactor vessel is 1375 psig (110% of the design value), which is the acceptance limit for pressurization events. The limiting pressurization event is a main steam isolation valve (MSIV) closure with a failure of the valve position scram. The MSIV closure was analyzed by the licensee using the NRC-approved methods, with the following exceptions: (1) the MSIV closure event was analyzed at 102% of the uprated core power, and (2) the maximum initial reactor dome pressure was assumed to be 1058 psig, which is higher than the nominal uprated pressure. The peak reactor pressure calculated was 1280 psig, which remains below the 1375 psig ASME Code limit. The NRC staff has evaluated the licensee's overpressure analysis and concluded that it is acceptable.

3.2.3 Reactor Recirculation System

Power uprate will be accomplished by operating along extensions of rod lines on the power/flow map with no increase in maximum core flow. The cycle-specific core reload analyses will be performed with the most conservative core flow. The evaluation by the licensee of the reactor recirculation system performance at uprated power determined that the core flow can be maintained with a slight increase (less than 1%) in pump speed.

The licensee estimates that the required pump head and pump flow at the uprated condition will increase the power demand of the recirculation motors and the pump net positive suction head (NPSH) by less than 2%.

The cavitation protection interlock will remain the same in absolute thermal power, since it is based on the feedwater flow rate. These interlocks are based on subcooling in the external recirculation loop and thus are a function of absolute thermal power. With power uprate, slightly more subcooling occurs in the external recirculation loop due to the higher RPV dome pressure. It would therefore be possible to lower the cavitation interlock setpoint slightly, but this change would be small and is not necessary.

An evaluation by the licensee of recirculation pump NPSH found that power uprate has a net effect of slightly increasing NPSH margin.

The recirculation drive flow stops were reviewed by the licensee for application to uprated power conditions. Since power uprate has such a small effect on the required flow rate, the drive flow limiter continues to have adequate input and output range with the capability for low and high limit setpoints.

The licensee concluded that uprated power operation is within the capability of the recirculation system. The licensee will continue to provide calibration of flow control, loop flow, and core flow instrumentation. As stated in Reference 2, these tests should be performed to assure that no undue vibration occurs at uprate or ELLL conditions. In a letter dated April 5, 1995, the licensee committed to monitor the existing instrumentation on the recirculation pump during and after power ascension. The NRC staff has concluded that these commitments are acceptable.

3.2.4 Main Steam Isolation Valves

The main steam isolation valves (MSIVs) have been evaluated by the licensee, and are consistent with the bases and conclusions of the generic evaluation. Increased core flow alone does not change the conditions within the main steam lines, and thus cannot affect the MSIVs. Performance will be monitored by surveillance requirements in the TS to ensure original licensing basis for MSIVs are preserved.

3.2.5 Reactor Core Isolation Cooling System

The reactor core isolation cooling system (RCIC) provides core cooling when the reactor pressure vessel (RPV) is isolated from the main condenser, and the RPV pressure is greater than the maximum allowable for initiation of a low pressure core cooling system. The RCIC system has been evaluated by the licensee, and is consistent with the bases and conclusions of the generic evaluation. In response to a staff request, the licensee has indicated by letter dated April 5, 1995, that the recommendations of GE SIL No. 377 have been implemented on the RCIC system of each Hatch unit. This modification is intended to achieve the turbine speed control/system reliability desired by GE SIL 377, and is consistent with the requirements in the staff Safety Evaluation of the generic topical report. The purpose of the modification is to mitigate the concern that a slightly higher steam pressure and flow rate at the RCIC turbine inlet will challenge the system trip functions such as turbine overspeed, high steam flow isolation, low pump suction pressure and high turbine exhaust pressure. The licensee also plans to perform startup testing on RCIC during the initial startup after being licensed at uprated power. The licensee has committed to test the RCIC system to provide assurance that it will be capable of injecting the design flow rates at the higher reactor operating pressures associated with power uprate. Additionally, the licensee has committed to evaluate the reliability of this system to provide assurance that its reliability will not be decreased by the higher loads placed on the system or because of any modifications made to the system to compensate for the increased loads.

3.2.6 Residual Heat Removal System

The residual heat removal system (RHR) is designed to restore and maintain the coolant inventory in the reactor vessel and to provide primary system decay heat removal following reactor shutdown for both normal and post-accident conditions. The RHR system is designed to operate in the low pressure coolant injection (LPCI) mode, shutdown cooling mode, suppression pool cooling mode, and containment spray cooling mode. The effects of power uprate on these operating modes are discussed below.

3.2.6.1 Shutdown Cooling Mode

The operational objective for normal shutdown is to reduce the bulk reactor temperature to 125°F in approximately 20 hours, using two RHR loops. At the uprated power level the decay heat is increased proportionally, thus slightly increasing the time required to reach the shutdown temperature. This increased time is judged to be insignificant.

Regulatory Guide 1.139, "Guidance for Residual Heat Removal," requires demonstration of cold shutdown capability (200°F reactor fluid temperature) within 36 hours. Final Safety Analysis Report Section 15.2.9 indicates that cold shutdown can be reached in a much shorter time even considering the availability of only one RHR heat exchanger. For power uprate, supplemental information contained in a letter dated April 5, 1995, provided an analysis of the alternate path for shutdown cooling based on the criteria of Regulatory Guide 1.139 that shows the reactor can be cooled to less than 212°F in 21 hours, which satisfies the 36-hour criterion.

3.2.6.2 Suppression Pool Cooling Mode

The Suppression Pool Cooling (SPC) Mode is designed to ensure that the pool temperature does not exceed its maximum temperature limit by removing heat from the containment during normal operation and after a blowdown in the event of a design basis loss-of-coolant accident (LOCA). This objective is satisfied for the power uprate, since the peak suppression pool temperature analysis performed by the licensee (described in Section 4.1.1 of the licensee submittal) confirms that the pool temperature will stay below its design limit at uprated conditions. The effect of higher suppression pool temperature on the NPSH of the RHR pumps during the SPC Mode is also discussed in Section 4.2 of the licensee submittal.

3.2.6.3 Containment Spray Cooling Mode

The Containment Spray Cooling (CSC) Mode provides water from the suppression pool to spray headers in the drywell and suppression chambers to reduce containment pressure and temperature during post-accident conditions. Power uprate increases the containment spray temperature by only a few degrees. This increase has a negligible effect on the calculated values of drywell pressure, drywell temperature, and suppression chamber pressure since these parameters reach peak values prior to actuation of the containment spray. The effect of the higher suppression pool temperature in reducing the NPSH available to the RHR pumps during the CSC Mode is discussed in Section 4.2 of the licensee's submittal. The results show that there is adequate NPSH margin during the CSC Mode under post-LOCA operating conditions.

The NRC staff has evaluated the effect of power uprate on the cooling modes of the RHR system discussed above and concluded they are acceptable.

3.2.7 Reactor Water Cleanup System

The Reactor Water Cleanup System (RWCU) pressure and temperature will increase slightly as a result of power uprate. The licensee has evaluated the impact of these increases and has concluded that uprate will not adversely affect system integrity. The cleanup effectiveness may be diminished slightly as a result of the increased feedwater flow to the reactor; however, the current limits for reactor water chemistry will remain unchanged for power uprate. The NRC staff has concluded that these effects on the RWCU system are acceptable.

3.3 Engineered Safety Features

3.3.1 Emergency Core Cooling Systems

The effect of power uprate and the increase in RPV dome pressure on each Emergency Core Cooling System (ECCS) is addressed below. Also, as discussed in the FSAR, compliance with the NPSH requirements of the ECCS pumps is based on a containment pressure of 8.2 psig for Unit 1 and 0 psig for Unit 2; and a maximum expected temperature of pumped fluids of 202°F. The pumps are assumed to be operating at the maximum flow with the suppression pool temperature at its highest value. Assuming a LOCA occurs during operation at the uprated power, the suppression pool temperature will remain below the value required for ECCS pump NPSH. Therefore, power uprate will not affect compliance to the ECCS pump NPSH requirements.

3.3.1.1 High Pressure Coolant Injection System

The High Pressure Coolant Injection (HPCI) system has been evaluated by the licensee, and is in agreement with the bases and conclusions of the generic evaluation. In response to a staff request, the licensee has indicated by letter dated April 5, 1995, that the modifications to the HPCI system of each of the Hatch units, in response to GE SIL 480 have been installed, and are consistent with the requirements in the staff SE of the generic topical report. The purpose of this modification is similar to that of the RCIC system as discussed in Section 3.2.5. The licensee also plans to perform startup testing on HPCI during the initial startup after being licensed at uprated power. The licensee has committed to test the HPCI system to provide assurance that the HPCI system will be capable of injecting its design flow rates at the higher reactor operating pressures associated with power uprate. Additionally, the licensee has committed to evaluate the reliability of the HPCI system to provide assurance that its reliability will not be decreased by the higher loads placed on the system or because of any modifications made to the system to compensate for the increased loads.

3.3.1.2 Low Pressure Coolant Injection System (LPCI mode of RHR)

The hardware for the LPCI mode portion of the RHR system is not affected by power uprate. The upper limit of the low pressure ECCS injection setpoints will not be changed for power uprate; therefore, the low pressure portions of these systems will not experience any higher pressures. The licensing and design flow rates of the low pressure ECCS will not be increased. In addition, the RHR system shutdown cooling mode flow rates and operating pressures will not be increased. Therefore, since the system does not experience different operating conditions, there is no impact due to power uprate. The licensee stated that both Hatch units are bounded by the generic analyses presented in Reference 4. The NRC staff has concluded that this is acceptable.

3.3.1.3 Core Spray System

The hardware for the low pressure core spray (CS) is not affected by power uprate. The upper limit of the low pressure ECCS injection setpoints will not be changed for power uprate; therefore, the low pressure portions of these systems will not experience any higher pressures. The licensing and design flow rates of the low pressure ECCS will not be increased. Therefore, since these systems do not experience different operating conditions, there is no impact due to power uprate. Also, the impact of power uprate on the long-term response to a LOCA will continue to be bounded by the short-term response. The licensee stated that both the Hatch units are bounded by the generic analyses presented in Reference 4. The NRC staff has concluded that this is acceptable.

3.3.1.4 Automatic Depressurization System

The Automatic Depressuruzation System (ADS) uses safety/relief valves to reduce reactor pressure following a small break LOCA with HPCI failure. This function allows LPCI and CS to flow to the vessel. The ADS initiation logic and ADS valve control are not affected by power uprate.

3.4 ECCS Performance Evaluation

The emergency core cooling systems (ECCS) are designed to provide protection against hypothetical loss-of-coolant accidents (LOCAs) caused by ruptures in the primary systems piping. The ECCS performance under all LOCA conditions and their analysis models must satisfy the requirements of 10 CFR 50.46 and 10 CFR Appendix K. The fuel used in Hatch Units 1 and 2 was analyzed by the licensee with the NRC-approved methods. The results of the ECCS-LOCA analysis using NRC-approved methods is presented in Table 4-2 of NEDC-32405P, the plant-specific ECCS-LOCA results for Hatch.

The licensee used the staff-approved SAFER/GESTR (S/G) methodology to assess the ECCS capability for meeting the 10 CFR 50.46 criteria. The S/G-LOCA analysis for Hatch Units 1 and 2 was performed by the licensee with the appropriate reload fuel in accordance with NRC requirements and demonstrates conformance with the ECCS acceptance criteria of 10 CFR 50.46 and Appendix K. A number of plant-specific break sizes sufficient to establish the behavior of both the nominal and Appendix K Peak Clad Temperature (PCT) as a function of break size was evaluated. Different single failures were also investigated in order to clearly identify the worst cases. The Hatch-specific analysis was performed with a conservatively high Peak Linear Heat Generation Rate (PLHGR) and a conservatively low Minimum Critical Power Ratio (MCPR). In addition, some of the ECCS parameters were conservatively established relative to actual measured ECCS performance. The analysis also meets the other acceptance criteria of 10 CFR 50.46. Compliance with each of the elements of 10 CFR 50.46 is documented in Table 4-2 of the GPC Licensing Topical Report. A 0.75 conservative multiplier will be utilized for single loop operation as previously accepted by the staff. The licensee provided further assurance by letter dated April 5, 1995, that the power uprate and fuel reload will not change the limiting break, single failure, or the break spectrum as compared to the existing analysis. Therefore, the staff concludes that Hatch Units 1 and 2 continue to meet the NRC-LOCA licensing analysis and results requirements.

3.5 Reactor Safety Performance Features

3.5.1 Reactor Transients

Reload licensing analyses evaluate the limiting plant transients. Disturbances of the plant caused by a malfunction, a single failure of equipment, or personnel error are investigated according to the type of initiating event. The licensee will use its NRC-approved licensing analysis methodology to calculate the effects of the limiting reactor transients as identified in the generic guidelines. The limiting events for the Hatch units were identified and the relatively small changes in rated power and maximum allowed core flow are not expected to affect the selection of limiting events. The events that will be explicitly evaluated for cycle-specific reload analyses are:

1. Loss of Feedwater Heating (LOFWH)
2. Feedwater Controller Failure (FWCF)
3. Generator Load Rejection without Bypass (GLRWOB)
4. Turbine Trip without Bypass (TTWOB)
5. Rod Withdrawal Error (RWE)
6. Recirculation Flow Controller Failure - Increase (RFCF)
7. Fuel Loading Error

The limiting events that establish the minimum critical power ratio (MCPR) operating limits are currently GLRWOB, FWCF, and LOFWH. These events are expected to remain limiting. The licensing analyses will be performed by the licensee up to a maximum power level of 102% of the uprated power level to account for power uncertainty, at each reload. The results of the transient analyses are presented in Table 9-2 of NEDC-32405P. The Unit 2 most recent reload analysis was used as the representative fuel cycle for the power uprate. The power uprate analysis used the staff-approved GEMENI methodology with the statistical allowance for 2% power uncertainty included in the analysis. Most of the transient events are analyzed at the full uprated power and maximum allowed core flow operating point as shown on the power/flow map.

The safety limit minimum critical power ratio (SLMCPR) is calculated by the licensee as part of the reload licensing analyses using the NRC-approved methodology for the appropriate reload fuel. No change will be made to this methodology due to power uprate or increased core flow. The analysis plan proposed by the licensee is acceptable. The NRC staff will verify the acceptability of the results when each reload document is submitted.

3.6 Special Events

3.6.1 Anticipated Transients Without Scram

A generic evaluation of the Anticipated Transient Without Scram (ATWS) event is presented in Section 3.7 of Supplement 1 to Reference 4. This evaluation concludes that the ATWS acceptance criteria for fuel, reactor pressure vessel (RPV), and the containment integrity will not be violated for power uprate if the following conditions are met: reactor power increase is equal to or less than 5%; dome pressure increase is equal to or less than 40 psi; SRV opening setpoint increase is equal to or less than 80 psi; and ATWS high pressure setpoint increases are equal to or less than 20 psi. The Hatch power uprate meets the four criteria with the exception that the ATWS high pressure setpoint was increased by 30 psi. The licensee has evaluated MSIV closure, which is the limiting ATWS event. The RPV integrity was reanalyzed with the power uprate input parameters of 2558 MWt; reactor dome pressure of 1035 psig; SRV opening setpoints increased by 30 psi; and ATWS high pressure setpoint increased by 30 psi to 1180 psig. The results showed the peak RPV pressure to be 1387 psig, which is below the ASME code limit of 1500 psig. The effects on fuel PCT and maximum suppression pool temperature were judged to be negligible because the calculations show no increase in heat flux or integrated SRV flow results. Based on the analysis in Reference 4 and the plant-specific Hatch analysis, power uprate will not result in any ATWS acceptance criteria being violated.

3.6.2 Station Blackout

Plant response and coping capabilities for a station blackout (SBO) event are impacted by operation at the uprated power level due to the increase in the operating temperature of the primary coolant system, increase in decay heat, and increase in the main steam safety relief valve setpoints. There are no changes to the systems and equipment used to respond to an SBO, nor is the coping time changed.

The following areas contain equipment necessary to mitigate the SBO event: Control Room and Relay Room; RCIC Corner Room; Steam Pipe Chase/Steam Tunnel; Drywell and Suppression Pool; and RHR Corner Room. The temperature increases in the Control and Relay Rooms are not affected by power uprate. The temperatures in the RCIC and RHR corner rooms will increase; however, the licensee stated that these temperature increases are bounded by the existing design. The main steam pipe chase/tunnel area temperature will also increase; however, the licensee has confirmed that the equipment with the lowest temperature needed for event mitigation is qualified for the increased temperatures. The licensee also stated that the equipment used to respond after power restoration is designed for the suppression pool peak temperature associated with power uprate. Furthermore, the licensee stated that the condensate water requirement for reactor vessel water makeup increases by less than 5%, and that the current design of the condensate storage tank includes a 20% margin which ensures that adequate water volume is available. Based on the above evaluation, the NRC staff has concluded that SBO coping capabilities are not adversely affected by power uprate and are acceptable.

The limiting parameters for SBO events lasting longer than 4 hours are water inventory for decay heat removal, Class 1E battery capacity, compressed air capacity, and the effects of loss of ventilation. Power uprate will result in more decay heat that will require a slightly larger water inventory. However, the current SBO analysis provides for adequate water inventory to meet the additional requirements of power uprate.

Class 1E battery capacity and the compressed air system are unaffected by power uprate, and power uprate will not increase demand on these systems for SBO scenarios. Therefore, the capacity of these systems will remain adequate.

3.7 Containment System Performance

The Hatch Units 1 and 2 FSARs provide the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation with power uprate changes some of the conditions for the containment analyses. Section 5.10.2 of Topical Report NEDC-31897 (Reference 2) requires the power uprate applicant to show acceptability of the uprated power level for: (1) containment pressures and temperatures, (2) LOCA containment dynamic loads, and (3) safety-relief valve discharge dynamic loads. Appendix G of NEDC-31897 prescribes the approach to be used by power uprate applicants for performing required plant-specific analyses. The licensee performed the necessary analyses and presented the results in its January 13, 1995, application and provided additional information in a letter dated April 5, 1995.

Appendix G of NEDC-31897 states that the applicant will analyze short-term containment responses using the staff-approved M3CPT code. M3CPT is used to analyze the period from when the break begins to when pool cooling begins. M3CPT generates data on the response of containment pressure and temperature, dynamic loads, and equipment qualification.

Appendix G of NEDC-31897 also states that the applicant will perform long-term containment heatup (suppression pool temperature) analyses for the limiting safety analysis report events to show that the pool temperatures will remain within limits for:

Containment design temperature,
Local pool temperature,
Net positive suction head (NPSH),
pump seals, piping design temperature, and other limits

These analyses will use the SHEX Code and ANS 5.1-1979 decay heat assumptions consistent with the staff's letter from Ashok Thadani to Gary L. Sozzi, Manager, Technical Services, GE Nuclear Energy, dated July 13, 1993. The SHEX Code, which is partially based on M3CPT, is a long-term Code to analyze the period from when the break begins until after peak pool heatup.

3.7.1 Containment Pressure and Temperature Response

Short-term and long-term containment analyses of containment pressure and temperature response following a large break inside the drywell for operation at 2,436 MWt are documented in the Hatch FSARs. The short-term analysis is performed primarily to determine the peak drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break inside the drywell (DBA-LOCA). The long-term analysis is performed primarily to determine the peak pool temperature response, considering the decay heat addition to the pool.

3.7.1.1 Long-Term Suppression Pool Temperature Response

(1) Bulk Pool Temperature

The licensee indicated that the long-term bulk suppression pool temperature response was analyzed for the DBA-LOCA for both 102% of original rated power and 102% of uprated power using the SHEX Code and ANS 5.1 decay heat assumptions prescribed by NEDC-31897. The licensee indicated that in addition to the higher reactor power level and dome pressure associated with power uprate, it used a higher initial drywell temperature (150°F instead of original 135°F) and higher initial drywell pressure (1.75 psig instead of original atmospheric pressure). Also, the RHR flow rate was degraded 10 percent to 6900 gpm/pump, consistent with the degradation assumed in the existing SAFER/GESTR-LOCA analysis. All other key input parameters for power uprate analyses were essentially the same as those for the original analyses. The analysis shows that power uprate results in an increase of 4°F in peak pool temperature, based on current methodology. For the power uprate, the DBA-LOCA peak suppression pool temperature was calculated to be 202°F. The peak pool temperatures are well below the wetwell structural design temperature of 281°F for Unit 1 and 340°F for Unit 2.

The licensee indicated that calculations also show that the available NPSH for the Core Spray and RHR pumps is adequate for both units during the long-term cooling period following a DBA-LOCA. For Unit 1, the wetwell pressure required to satisfy NPSH requirements at 202°F peak pool temperature is approximately 0 psig, as compared to the 8.2 psig wetwell pressure available. For Unit 2, the peak pool design temperature for NPSH requirements is approximately 220°F for both Core Spray and all RHR pumps, as compared to the 202°F peak pool temperature.

Based on the results of these analyses, the NRC staff concludes that the peak bulk suppression pool temperature response remains acceptable from both NPSH and structural design standpoints after power uprate.

(2) Local Pool Temperature with SRV Discharge

The local pool temperature limit for SRV discharge is specified in NUREG-0783, because of concerns resulting from unstable condensation observed at high pool temperatures in plants without quenchers. The licensee indicated that since both units of Hatch have quenchers, no evaluation of this limit is considered necessary. Elimination of this limit for plants with quenchers on the SRV discharge lines is justified in GE report NEDO-30832, "Elimination of Limits on Local Suppression Pool Temperature for SRV Discharge with Quenchers."

Based on the review of the licensee's submittals, the NRC staff concludes that the peak local pool temperature will remain acceptable after power uprate.

3.7.1.2 Containment Gas Temperature Response

The licensee indicated that the containment gas temperature response analyses were performed to cover the blowdown period for DBA-LOCA during which the maximum drywell airspace temperature occurs, both at 102% of rated power and at 102% of uprated power using the current methodology. The results show that the power uprate will increase the calculated peak drywell gas temperatures by 2-3°F from 290°F to 292°F for Unit 1 and from 289°F to 292°F for Unit 2. For Unit 2, the calculated peak drywell gas temperature remains less than the shell design temperature of 340°F. However, the Unit 1 calculated peak drywell gas temperature exceeds its drywell shell design temperature of 281°F by 11°F, but only at the beginning of the accident for a short period of less than 20 seconds. Due to the very short duration of the increase relative to the time required for the drywell shell to heat up, the exceedence is not considered a threat to drywell shell structure and the containment gas temperature response analyses are considered acceptable.

The licensee indicated that the wetwell gas space peak temperature response was calculated assuming thermal equilibrium between the pool and wetwell gas space. The reanalysis has shown that the maximum bulk pool temperature will reach 202°F after a LOCA. Therefore, the maximum wetwell gas space temperature due to power uprate will remain below the wetwell design temperature of 281°F for Unit 1 and 340°F for Unit 2.

Based on the review of the licensee's submittals, the NRC staff concludes that the containment drywell and wetwell gas temperature response will remain acceptable after power uprate.

3.7.1.3 Short-Term Containment Pressure Response

The licensee indicated that the short-term containment response analyses were performed for the limiting DBA-LOCA, which assumes a double ended guillotine break of a recirculation suction line to demonstrate that power uprate operation will not result in exceeding the containment design pressure limits. The short-term analysis covers the blowdown period during which the maximum drywell pressure and differential pressure between the drywell and wetwell occur. These analyses were performed at 102% of the uprated power level, using the GE M3CPT computer code. The reanalysis predicted a maximum containment pressure of 49.6 psig for Unit 1 and 45.5 psig for Unit 2 which remains below the containment design pressure of 62 psig for both Hatch units.

Technical specifications definitions, limiting conditions for operation, surveillance requirements, and bases relating to the limiting peak accident pressure, P_a, are revised to reflect the new analyses.

Based on the review of the licensee's submittals, the NRC staff concludes that the containment pressure response following a postulated LOCA will remain acceptable after power uprate.

3.7.2 Containment Dynamic Loads

3.7.2.1 LOCA Containment Dynamic Loads

NEDC-31897 requires that the power uprate applicant determine if the containment pressure, suppression pool temperature and vent flow conditions calculated with the M3CPT code for power uprate are bounded by the analytical or experimental conditions on which the previously analyzed LOCA dynamic loads were based. If the new conditions are within the range of conditions used to define the loads, then LOCA dynamic loads are not affected by power uprate and thus do not require further analysis.

The licensee indicated that the LOCA dynamic loads which are considered in the power uprate evaluation include pool swell, condensation oscillation (CO), and chugging. For a Mark I plant, such as Hatch, the vent thrust loads are also evaluated. The short-term containment response conditions with power uprate are within the range of test conditions used to define the pool swell and condensation oscillation loads for the plant. The long-term response conditions with power uprate, in which chugging would occur, are within the conditions used to define the chugging loads. The vent thrust loads with power uprate are calculated to be less than plant-specific values calculated during the Mark I Containment Long-Term Program (LTP). Therefore, the LOCA dynamic loads for Hatch Units 1 and 2 are not impacted by power uprate.

Based on the review of the licensee's submittals, the NRC staff concludes that the LOCA containment dynamic loads will remain acceptable after power uprate.

3.7.2.2 Safety-Relief Valve Containment Dynamic Loads

The safety-relief valve (SRV) containment dynamic loads include discharge line loads (SRVDL), suppression pool boundary pressure loads, and drag loads on submerged structures. These loads are influenced by SRV opening setpoints pressure, SRV discharge line configuration and suppression pool configuration. Of these parameters only the SRV setpoint is affected by power uprate. NEDC-31897 states that if the SRV setpoints are increased, the power uprate applicant will attempt to show that the SRV design loads have sufficient margin to accommodate the higher setpoints.

The licensee indicated that the analytical limits for setpoints with power uprate are being increased by approximately 6 percent due to power uprate and to support conservative tolerance on the open setpoint pressure. The highest analytical limit for SRV setpoint is 1163.9 psig for Unit 1 and 1174.2 psig for Unit 2. Since the highest setpoint with power uprate remains lower than the setpoint of 1195 psig that was the basis for the current analyses of SRVDL and the SRV loads on the suppression pool boundary and submerged structures, power uprate does not impact the SRV definitions for the first actuations of SRVs.

Subsequent actuation loads may be affected by changes in the SRV discharge line water level in addition to the increase in loads due the pressure setpoint change. The licensee indicated that Hatch Units 1 and 2 have implemented low-low set with setpoints which are unchanged with power uprate. It has been demonstrated for Hatch Units 1 and 2 that with low-low set there will be sufficient time between SRV actuations to assure that subsequent actuations occur with the water level at the pre-actuation equilibrium level. Therefore, there will be no additional impact of power uprate on the subsequent actuation loads. The SRV containment dynamic loads will remain below their original design values after power uprate.

Based on the review of the licensee's submittals, the NRC staff concludes that the SRV containment dynamic loads will remain acceptable after power uprate.

3.7.2.3 Subcompartment Pressurization

The licensee indicated that due to operation at a higher pressure with power uprate, the actual asymmetrical loads on the vessel, attached piping, and biological shield wall from a postulated pipe break in the annulus between the reactor vessel and biological shield wall increase slightly. The biological shield wall and component designs remain adequate because the original analyzed loads were based on mass and energy releases that bound the uprated conditions. It is also noted that the NEDC-31897 methodology does not require subcompartment reanalysis. Based on the above, the NRC staff concludes that the subcompartment pressurization effects will remain acceptable after power uprate.

3.7.3 Containment Isolation

The NEDC-31897 methodology does not address a need for reanalysis of the isolation system. The system designs for containment isolation are not affected by power uprate. The capability of the actuation devices to perform with uprated pressure and flow will comply with the acceptability criteria of Generic Letter 89-10.

Based on the review of the licensee's submittals, the NRC staff concludes that the operation of the plant at uprated power level will not impact the containment isolation system.

3.7.4 Post-LOCA Combustible Gas Control

The control of combustible gas concentrations for Unit 1 is attained by containment atmosphere dilution (CAD) method. This method adds nitrogen to the containment to dilute the oxygen concentration below the flammability limit. The licensee indicated that sufficient capacity exists in the Unit 1 CAD system to account for the increase in oxygen generation due to power uprate. Unit 2 combustible gas control system is provided with hydrogen recombiners, which maintain a safe level of hydrogen inside the containment. The initiation of the recombiners is controlled procedurally to maintain gas concentration within 4% volume inside containment following a LOCA, and not by time. The impact of a power uprate might be that the Unit 2 recombiner would initiate slightly earlier. The licensee indicated that additional margin is available by designing to control hydrogen within 3.5% volume. Containment purge capability serves as a backup to the Unit 1 CAD system and Unit 2 recombiner system.

Based on its review, the NRC staff concludes that the post-LOCA combustible gas control will remain acceptable after uprated power.

3.8 Standby Gas Treatment System

The standby gas treatment system (SGTS) is designed to achieve and maintain a slightly negative pressure (with respect to the outside atmosphere) in the secondary containment (SC) following a LOCA to prevent unfiltered release of radioactive material from the SC to the environment. As a result of plant operation at the proposed uprated power level, heat loads from piping in the SC will increase slightly. This increase in piping heat loads, in turn, may cause a slight increase in the pressure drawdown time in the SC. The licensee stated that the capability of the SGTS to achieve a slightly negative pressure in the SC is not impacted by the power uprate. The licensee also stated that the total post-LOCA iodine loading on the filters of the SGTS will increase slightly, but it will remain well below the original design capacity of the filters.

Based on the review of the licensee's submittals and experience gained from the review of previous power uprate applications for similar BWR plants, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the SGTS.

3.9 Main Control Room Atmosphere Control System

The control room atmosphere control system (CRACS) containing an emergency filtration system is designed to maintain the control room envelope at a slightly positive pressure relative to the outside atmosphere and thus minimize unfiltered inleakage of contaminated outside air into the control room following a LOCA. Since plant operation at the proposed uprated power level does not change the design and operational aspects of the CRACS, the licensee stated that the proposed uprated power level will not have a significant impact on the CRACS.

Based on the review of the licensee's submittals and experience gained from the review of previous power uprate applications for similar BWR plants, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the CRACS.

3.10 Spent Fuel Pool Cooling System

The spent fuel pool cooling system (SFPCS) is designed to remove the decay heat released from the stored spent fuel assemblies and maintain the pool water temperature at or below design temperature under normal operating conditions. Supplemental fuel pool cooling is provided by the residual heat removal (RHR) system in the event of full core off-load.

As a result of plant operation at the proposed uprated power level, the spent fuel pool heat load will increase slightly. The licensee performed an evaluation and concluded that the power uprate will not have any negative effect on the capability of the fuel pool cooling system and the RHR system in the fuel pool cooling assist mode to maintain adequate fuel pool cooling during normal and maximum (full core off-load) conditions.

Based on the review of the licensee's submittals and experience gained from the review of previous power uprate applications for similar BWR plants, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the design aspects and operation of the SFPCS and the RHR system in the fuel pool cooling assist mode.

An issue associated with spent fuel pool cooling adequacy was identified in NRC Information Notice 93-83, "Potential Loss of Spent Fuel Pool Cooling Following a Loss-of-Coolant Accident (LOCA)," October 7, 1993, and in a 10 CFR Part 21 notification, dated November 27, 1992. The staff is evaluating this issue, as well as broader issues associated with spent fuel storage safety, as part of the NRC generic issue evaluation process. If the generic review concludes that additional requirements in the area of spent fuel pool safety are warranted, the NRC staff will address those requirements to the licensee independent of this review.

3.11 Water Systems

The licensee evaluated the impact of power uprate on the following plant water systems: service water systems; residual heat removal system; main condenser; circulating water system; cooling tower system; reactor building closed cooling water system; and the ultimate heat sink.

3.11.1 Plant Service Water System

The plant service water system (PSWS) is designed to provide cooling water to various systems (both safety-related and non safety-related), and to provide makeup to the plant circulating water system. The licensee, having performed evaluations, stated that the heat loads for components affected by plant operation at the proposed uprated power level are not significant and are within the existing design heat loads. Therefore, the design of PSWS is adequate for power uprate conditions.

Based on the review of the licensee's submittals, the NRC staff concludes that plant operation at the proposed uprated power level does not change the design aspects and operation of the PSWS.

Therefore, the NRC staff agrees with the licensee that plant operation at the proposed uprated power level will not have a significant impact on the PSWS.

3.11.2 Residual Heat Removal Service Water System

The residual heat removal service water system (RHRSWS) provides safety-related cooling water to the residual heat removal (RHR) system under normal or post-accident conditions. The licensee stated that in the revised analysis for containment pressure and temperature response to demonstrate the containment system capability to operate with uprated power, the RHR cooling capacity during post-LOCA was assumed not to increase for power uprated conditions. Therefore, power uprate will not change the cooling requirements on RHR and its associated service water system for post-LOCA conditions. During shutdown cooling with the RHR, heat loads on the RHRSW system will increase proportionally to the increase in reactor operating power level. The licensee, based on evaluations performed, stated that the existing design cooling capacity of the RHRSWS is adequate for the proposed uprated power operation.

Based on the review of the licensee's submittals, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the RHRSWS.

3.11.3 Main Condenser, Circulating Water, and Cooling Tower Systems

The circulating and cooling tower water systems are designed to provide the main condenser with a continuous supply of cooling water for removing heat rejected to the condenser by turbine exhaust, turbine bypass steam, and other exhausts over the full range of operating loads thereby maintaining low condenser pressure. The licensee stated that the performance of the main condenser, circulating water, and cooling tower systems was evaluated and found adequate for plant operation at the proposed uprated power level.

Since the main condenser, circulating water, and cooling tower systems do not perform any safety related function, the NRC staff has not reviewed the impact of the proposed uprated power operation on the design and performance of these systems.

3.11.4 Reactor Building Closed Cooling Water System

The reactor building closed cooling water system (RBCCWS) is designed to remove heat from various auxiliary plant equipment housed in the reactor building. The licensee, based on evaluations performed, stated that the increase in heat loads to this system due to uprated power operation is not significant and is within the existing design heat loads.

Since plant operation at the proposed uprated power level do not change the design aspects and operation of the RBCCWS, the NRC staff is in agreement with the licensee that the impact of plant operation at the proposed uprated power level on the RBCCWS is not significant.

3.11.5 Ultimate Heat Sink

The ultimate heat sink (UHS) for Hatch Units 1 and 2 is the Altamaha River. The licensee stated that the temperature of the river is unaffected by uprate and will continue to provide a sufficient quantity of water at a temperature less than design temperature following a design basis accident. In addition, the licensee stated that an evaluation of plant operating parameters impacted by the power level uprate concludes that no significant environmental impact will result from operation of the Hatch units at the uprated power level.

Based on the review of the licensee's submittals, the NRC staff concludes that the UHS design is adequate for plant operation at the proposed uprated power level and no modification to the UHS system is required.

3.11.6 Heating, Ventilation, and Air Conditioning Systems

The heating, ventilation, and air conditioning (HVAC) systems consists mainly of cooling supply, exhaust and recirculation units in the reactor building, drywell, and turbine building. The licensee stated that the areas affected by power uprate consist of the drywell, steam tunnel, and feedwater heater and condenser areas in the turbine building. The licensee performed evaluations which indicated that the area design temperatures for all plant operating modes envelop the temperatures resulting from the anticipated increase in heat loads due to plant operation at the proposed uprated power level. Thus, the existing design of the HVAC systems for the above cited areas is acceptable for plant operation at the uprated power level.

Based on the review of the licensee's submittals, the NRC staff agrees with the licensee that plant operation at the proposed uprated power level does not have a significant impact on the HVAC systems for the above cited areas.

3.12 Fire Protection

The licensee stated that the Hatch 10 CFR Part 50 Appendix R Fire Hazard Analysis Report and the Safe Shutdown Analysis Report were reviewed and it was concluded that plant operation at the proposed uprated power level does not affect the ability of the Appendix R systems to perform their safe shutdown function.

Fire suppression or detection is not expected to be impacted due to plant operation at the proposed uprated power level since there are no physical plant configurations or combustible load changes resulting from the uprated power operation. The safe shutdown systems and equipment used to achieve and maintain cold shutdown conditions do not change and are acceptable for the uprated conditions, and the operator actions required to mitigate the consequences of a fire are not affected.

Based on the review of the licensee's submittals, the NRC staff agrees with the licensee that the fire suppression and detection systems are not power dependent and will not be affected by plant operation at the proposed uprated power level.

3.13 Power Conversion Systems

The steam and power conversion systems and their associated components (e.g., the turbine/generator, condenser and steam jet air ejector, turbine steam bypass, feedwater and condensate systems, etc.) were designed to utilize the energy available from the nuclear steam supply system. The original system and equipment sizing was based on 105% of steam flow rates. The licensee, having conducted evaluations, stated that the existing systems and equipment are acceptable for plant operation at the proposed uprated power level.

Based on the review of the licensee's submittals, the NRC staff agrees with the licensee that operation of the power conversion systems at the proposed uprated power level is acceptable.

3.13.1 Turbine-Generator

Evaluations were performed for turbine operation with respect to design acceptance criteria to verify the mechanical integrity under the conditions imposed by the power uprate. Results of the evaluations showed that there would be no increase in the probability of turbine overspeed nor associated turbine missile production due to plant operation at the proposed uprated power level. Therefore, the licensee concluded that the turbine could continue to be operated safely at the proposed uprated power levels.

Based on the review of the licensee's submittals, the NRC staff agrees with the licensee that operation of the turbine at the proposed uprated power level is acceptable.

3.14 Waste Management

3.14.1 Liquid Waste Management

The liquid radwaste system is designed to process the majority of the liquid wastes within the plant so that the liquids discharged from the plant satisfy the 10 CFR Part 20 and 10 CFR Part 50 Appendix I requirements. The activated corrosion products in liquid wastes are expected to increase proportionally to the power uprate. The single largest source of liquid waste is from the backwash of the condensate demineralizers. With power uprate, the average time between backwash/precoat will be reduced slightly. The reduction does not affect plant safety. Reactor coolant cleanup flows, leaks, laboratory drains, dry solid waste, and spent resin quantities will remain essentially the same after power uprate.

The licensee stated that the total volume of processed liquid waste is not expected to increase appreciably due to plant operation at the proposed uprated power level since the only significant increase in processed waste is due to the more frequent backwashes of condensate demineralizers. The licensee performed evaluations of plant operation and effluent reports, and concluded that the requirements of 10 CFR Part 20 and 10 CFR Part 50 Appendix I will continue to be satisfied.

Based on the review of the licensee's submittals, the NRC staff agrees with the licensee's conclusion and determined that the liquid radwaste system is acceptable.

3.14.2 Gaseous Waste Management

Gaseous wastes generated during normal and abnormal operation are collected, controlled, processed, stored, and disposed utilizing the gaseous waste processing treatment systems. These systems, which are designed to meet the requirements of 10 CFR Part 20 and 10 CFR Part 50 Appendix I, include the offgas system and standby gas treatment system, as well as other building ventilation systems. Various devices and processes, such as radiation monitors, filters, isolation dampers, and fans, are used to control airborne radioactive gases. Results of the licensee's analyses demonstrate that airborne effluent activity released through building vents will not increase significantly due to plant operation at the proposed uprated power level.

Based on the review of the licensee's submittals, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the above systems.

3.15 High Energy Line Breaks Outside Containment

The slight increase in the reactor operating pressure and temperature resulting from the plant operation at the proposed uprated power level will cause a small increase in the mass and energy release rates following a high energy line break (HELB) outside the primary containment. This results in a small increase in the subcompartment pressure and temperature profiles. The licensee conducted evaluations for the HELB in the main steam, feedwater, high pressure coolant injection, reactor core isolation cooling, reactor water cleanup, and control rod drive piping systems. Based on these evaluations the licensee concluded that the existing HELB temperature and pressure analyses envelop those resulting from the proposed uprated power operation and that there is no change in postulated break locations due to plant operation at the proposed uprated power level.

Based on the review of the licensee's submittals, the NRC staff concludes that the existing analysis for HELB remains bounding and is acceptable for plant operation at the proposed uprated power level.

3.16 Equipment Qualification

The licensee evaluated the effects of plant operation at the proposed power level on qualified equipment including safety-related electrical equipment and mechanical components.

3.16.1 Inside Containment

With regard to the radiation levels used for safety-related equipment qualification (EQ), the licensee stated that the existing calculated radiation levels were assumed to increase 5%. The licensee performed a review of equipment qualification for power uprate conditions and identified some equipment located within the containment that may potentially be affected by the higher accident radiation levels. However, the qualification of this equipment was evaluated and was found acceptable for power uprate conditions.

With regard to the temperatures and pressures used for qualifying equipment inside containment, the licensee stated that the results of existing calculations remain bounding for those temperatures and pressures resulting from plant operation at the proposed power level.

Based on the review of the licensee's submittals, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the EQ of safety-related equipment including electrical equipment and mechanical components inside the containment and, therefore, is acceptable.

3.16.2 Outside Containment

With regard to the parameters (e.g., temperatures, pressures, radiation levels) used for qualifying equipment outside containment, the licensee stated that the results of existing calculations remain bounding for the conditions resulting from plant operation at the proposed power level.

Based on the review of the licensee's submittals, the NRC staff concludes that plant operation at the proposed uprated power level will not have a significant impact on the EQ of safety-related equipment including electrical equipment and mechanical components outside the containment and, therefore, is acceptable.

3.17 Mechanical Component Design Qualification

The NRC staff's review of the safety analysis report provided by the licensee, focused on the effects of power uprate on the structural and pressure boundary integrity of the piping systems and components, their supports, reactor vessel and internal components, the Control Rod Drive Mechanism (CRDM), and the balance-of-plant (BOP) piping systems.

The GE generic guidelines for BWR power uprate were based on a 5% higher steam flow, an operating temperature increase of 5°F and an operating pressure increase of 40 psi or less. For Hatch, the maximum reactor vessel dome pressure increases from 1005 psig to 1035 psig (30 psi increase), the dome temperature increases from 547°F to 551°F (4°F increase) and the steam flow rate increases from $10.0x10^6$ lb_m/hr to $10.6x10^6$ lb_m/hr for Unit 1 and from $10.5x10^6$ lb_m/hr to $11.1x10^6$ lb_m/hr for Unit 2. The maximum core flow rate remains unchanged for the Hatch power uprate conditions.

3.17.1 Reactor Pressure Vessel (RPV) and Internals

The licensee evaluated the reactor vessel and internal components by considering load combinations that include reactor internal pressure difference (RIPD), loss-of-coolant accident (LOCA), and seismic loads. The seismic loads are unaffected by the power uprate. The licensee recalculated RIPDs for the power uprate shown in Tables 3-2, 3-3 and 3-4 of Reference 5, for normal, upset, and faulted conditions respectively.

The stresses and cumulative fatigue usage factors (CUFs) for reactor vessel components were evaluated by the licensee in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1965 Edition with Winter 1966 Addenda for Unit 1, and 1968 Edition with Summer 1970 Addenda for Unit 2, to assure compliance with the Code of Record. The load combinations for normal, upset and faulted conditions were considered in the evaluation. The maximum stresses for critical components were summarized in Table 3-1 of Reference 5.

The CUFs for the uprated power level were calculated by using the power uprate scaling factor for limiting components such as feedwater nozzle, CRD nozzle, vessel shell and closure region bolts. The calculated CUFs were provided in Table 3-4 of Reference 2. In its April 5, 1995, response to the staff's request for additional information, the licensee indicated that the CUF for the Unit 2 feedwater nozzle was calculated to be 0.93 based on the actual plant operating data combined with the design basis CUF calculated for the power uprate. The staff finds that the actual operating cycle information has been used to compute the plant CUFs by other nuclear plant facilities, and the CUFs so calculated are realistic and acceptable.

In Reference 5, the licensee stated that the power uprate evaluation included the Unit 1 shroud modification. The future Unit 2 shroud repair design will be fully analyzed for the uprated power conditions. The current Unit 1 shroud modification was designed based on the Boiling Water Reactor Vessel Internal

Project's (BWRVIP's) criteria for no separation during normal operation. However, a design discrepancy, which could result in a gap in the shroud under certain postulated conditions, was recently identified. In a GPC letter to NRC dated February 20, 1995 (Reference 6), the licensee committed to comply with the shroud repair criteria established by the BWRVIP prior to the implementation of the power uprate.

Based on the review and the licensee's commitments, the NRC staff concludes that the maximum stresses and fatigue usage factors as provided by the licensee are within the Code-allowable limits and that the reactor vessel and internal components will continue to maintain the structural integrity for the power uprate.

3.17.2 Control Rod Drive System

The licensee evaluated the adequacy of the CRDM in accordance with the Code of Record, the ASME Boiler and Pressure Vessel Code Section III, 1965 Edition and Addenda through Winter 1966 for Unit 1, and 1968 Edition and Addenda through Summer 1970 for Unit 2, and concluded that all stresses and fatigue usage factors will remain within the design basis allowables.

The increase in the reactor dome pressure and operating temperature as a result of the power uprate are bounded by the conditions assumed in the General Electric generic guidelines for the power uprate. The licensee evaluated the CRDM for the dome pressure of 1035 psig and an additional 40 psid for the vessel bottom head. The CRDM was designed for a dome pressure of 1250 psig which bounds the uprated power condition.

Based on the review of the licensee's submittals, the NRC staff concludes that the CRDM will continue to meet its design basis and performance requirements at uprated power conditions.

3.17.3 Reactor Coolant Piping and Components

The licensee evaluated the effects of the power uprate conditions, including higher flow rate, temperature and pressure for thermal expansion, fluid transients and vibration effects on the reactor coolant pressure boundary (RCPB) and the balance-of-plant (BOP) piping systems and components. The components evaluated included equipment nozzles, anchors, guides, penetrations, pumps, valves, flange connections, and pipe supports. The original Code of Record as specified in the Hatch FSARs, the Code allowables, and analytical techniques were used. No new assumptions were introduced that were not in the original analyses.

The RCPB piping systems evaluated include main steam piping, reactor recirculation piping, reactor vessel bottom head drain line, reactor water clean-up (RWCU), reactor vessel head vent line, reactor core isolation cooling (RCIC), condensate and feedwater system, high pressure coolant injection piping (HPCI), residual heat removal (RHR) and control rod drive piping (CRDS). The licensee's evaluation of the RCPB piping systems consisted of comparing the maximum increase in stress for the power uprate (due to increase in pressure and temperature) against the input parameters in the original design basis analyses. As summarized in a table of the piping evaluations in Reference 7, a majority of the RCPB systems were originally designed to maximum temperatures and pressures that bounded the increased operating temperature and pressure due to the power uprate, and are, therefore, acceptable.

For the those systems whose design temperature and pressure did not envelop the uprated power conditions, the licensee performed stress analyses in accordance with requirements of the Code and the Code addenda of Record under the power uprate conditions. The licensee concluded that the Code requirements are satisfied for the evaluated piping systems and that power uprate will not have an adverse effect on the reactor coolant piping system design.

The licensee evaluated the stress levels for BOP piping and supports in a manner similar to the evaluation of the RCPB piping and supports based on increases in temperature and pressure of the design basis analysis input. The adequacy of BOP systems was determined from the uprated reactor and BOP heat balances. These systems include lines that are affected by power uprate; but not evaluated in Section 3.5 of Reference 5, such as main steam bypass lines, the main steam relief valve discharge, and portions of main steam and feedwater systems outside the primary containment. The limiting stress ratios of maximum calculated stresses to the allowable, resulting from the BOP piping evaluations for the power uprate are shown in Table 16-1 of Reference 8 and Table 1 of Reference 7. The staff concludes that the stress ratios as provided by the licensee are within the Code-allowable limits and are therefore acceptable.

The licensee evaluated pipe supports including anchorages, equipment nozzles, and penetrations by comparing the increased piping interface loads on the system components due to the power uprate thermal expansion, with the margin in the original design basis calculation, and performing detailed analyses using exact load combinations at the uprated conditions. The effect of power uprate conditions on thermal and vibration displacement limits was also evaluated by the licensee for struts, springs and pipe snubbers, and found to be acceptable. The licensee reviewed the original postulated pipe break analysis and concluded that the existing pipe break locations were not affected by the power uprate, and no new pipe break locations were identified.

Based on the review of the licensee's submittals, the NRC staff concludes that the design of piping, components and their supports will be adequate to maintain the structural and pressure boundary integrity of the reactor coolant piping and supports in the power uprate conditions.

3.17.4 Equipment Seismic and Dynamic Qualification

Based on the review of the proposed power uprate amendment, the NRC staff concludes that the original seismic and dynamic qualification of the safety-related mechanical and electrical equipment is not affected by the power uprate conditions for the following reasons:

1. Seismic loads are unchanged for the power uprate; and

2. No new pipe break locations resulted from the uprated conditions.

3.18 Reactor Vessel Fracture Toughness

In the January 13, 1995, submittal, the licensee stated that operation with power uprate may result in a higher neutron flux, which may increase the integrated fluence over the period of plant life. The NRC staff reviewed the effects of increased neutron fluence on fracture toughness of reactor vessel materials in terms of (1) adjusted reference temperatures (ARTs) of reactor vessel materials based on Regulatory Guide 1.99, Revision 2; (2) the upper shelf energy based on Appendix G to 10 CFR 50, (3) pressure-temperature (P-T) limits based on Appendix G to 10 CFR 50; and (4) the withdrawal schedule of reactor vessel material surveillance capsules based on Appendix H to 10 CFR Part 50.

In the April 5, 1995, submittal, as supplemented by a submittal dated June 20, 1995, the licensee provided adjusted reference temperatures (ART) of the reactor vessel materials based on the higher neutron fluence. For Unit 1, the limiting (e.g., maximum) ART at 32 EFPY was calculated to be 163.9°F for the lower and lower-intermediate shell girth weld I-313, heat 90099. For Unit 2, the limiting ART was calculated to be 71.9°F for longitudinal weld 101-842, heat 10137. The staff verified that the licensee's ART calculations followed Regulatory Guide 1.99, Revision 2, and the limiting ARTs satisfied 200°F required by Appendix G to 10 CFR Part 50.

The licensee stated that the upper shelf energy will maintain an acceptable margin based on Appendix G to 10 CFR Part 50. Appendix G requires that under neutron irradiation the upper shelf energy of reactor vessel materials at end-of-license be maintained above 50 ft-lb. As permitted by Appendix G, the licensee submitted an equivalent margin analysis as documented in General Electric Topical Report NEDO-32205, Revision 1. Based on its review, the NRC staff determined that an acceptable margin will be maintained.

For Unit 2, the NRC staff determined that lower intermediate shell plate G6601-4, heat C8579-2, was the limiting material in terms of upper shelf energy reduction. The staff estimated the upper shelf energy at end-of-license for the weld to be 62 ft-lb. With a 10% increase in neutron fluence, the staff estimated that the upper shelf energy of the weld will be maintained above 50 ft-lb.

The licensee stated that the pressure-temperature (P-T) limit curves in the TS remain bounding for both Hatch Units 1 and 2 and that prior to the P-T curves becoming non-bounding, the curves will be re-evaluated, including power uprate conditions, when the surveillance capsules are removed from the reactor vessel at 15 EFPY. For Unit 1, the current P-T limit curves are applicable for 16 EFPY, which was based on a limiting ART of 133°F. The licensee calculated a limiting ART for 17 EFPY P-T curves using a combination of neutron fluence at 16 EFPY at 100% power and 1 EFPY at 110% power. The resulting ART was 132°F

1 EFPY of operation at 110% power. After that 1 EPFY period, the P-T limits will be revised in spring 1997. This will coincide with the testing and the removal of the second surveillance capsule from Unit 1 beginning spring 1996. For Unit 2, the power uprate will not affect the P-T curves because the non-beltline curves are still limiting even when evaluating the ART to end of license at 110% power uprate. The staff concluded that the current P-T curves for both Hatch units will not be affected by the power uprate.

The licensee stated that, as a result of power uprate, the leakage test pressure is increased by 30 psi from 1005 psig to 1035 psig and the hydrostatic test pressure is increased by 33 psi from 1106 psig to 1139 psig. The NRC staff determined that these pressure increases will not cause significant impact to the vessel structural integrity.

The licensee stated that a review of ASTM E185-82 indicates that the power uprate will not have a significant impact on the current surveillance capsule withdrawal schedule because the change in ART for a 10% increase in neutron fluence is less than 5°F. The NRC staff is in agreement with the licensee's assessment.

3.19 Reactor Internals and Pressure Differentials

Core Shroud Modifications: The licensee stated that the Unit 1 core shroud repair was designed and analyzed for the uprated condition. However, the licensee identified a design discrepancy that could result in a small gap in the shroud during normal operation if a complete through-wall circumferential crack is assumed. In the April 5, 1995, letter, the licensee committed to criteria that do not allow for gaps during normal operation. In a letter dated February 20, 1995, the licensee stated that shroud repair criteria will consider the power uprate conditions and will be in place before startup from the Unit 1 outage in spring 1996. Unit 1 will not be operated above 100% power without (1) modifying the repair such that no separation occurs, (2) performing additional analysis showing that no separation occurs or, (3) making a separate submittal for review and approval should the criteria not be met. The NRC staff concludes that the licensee's commitments related to core shroud repair criteria are acceptable.

The licensee stated that the Unit 2 core shroud repair design will be fully analyzed for uprated conditions. The NRC staff concludes this commitment is acceptable.

3.20 Balance-of-Plant Piping

Power uprate at Hatch Units 1 and 2 will result in a change in the operating condition of the plant. As a result, certain operating variables may undergo change that will have some impact on flow accelerated corrosion (FAC) of plant components. More specifically, it is expected that the change in fluid velocity, temperature and moisture content of two phase fluid may make damage caused by FAC to carbon steel components more pronounced.

In order to prevent component failures by FAC, the NRC, in Generic Letter 89-08, requested all licensees to have a long-term monitoring program. Such a program was implemented at the Hatch plants. The program is based on EPRI's CHECWORKS computer code. It predicts potential damage to the carbon steel components caused by FAC and permits the licensee to identify and repair or replace defective components, before their failures occur. As a result of this program, the NRC staff concludes that any increase in FAC that may occur due to power upgrade will be adequately handled by the licensee and will not cause degradation of the plant safety.

3.21 <u>Instrumentation and Control</u>

Many of the TS changes proposed by the licensee for the power uprate involve the Reactor Protection System trip and interlock setpoints, and are intended to maintain the same margin between operating conditions and trip setpoints as existed before the proposed power uprate.

The conservative design calculations for the initial licensing of Hatch 1 and 2 resulted in setpoints that provided excess reactor coolant flow capacity and corresponding margins in the power conversion system. For Hatch Units 1 and 2, these margins (e.g., 5% rated steam flow) result in the capability to increase the core operating power level by approximately 4.2%, whereas the licensee has requested to amend the Hatch licenses to operate at 105% of the current power level. This section of the safety evaluation addresses setpoint changes for the identified instrumentation and is predicated on the assumption that the analytical limits used by the licensee are based on application of approved design codes.

The following setpoint changes have been proposed by the licensee:

1. Reactor Pressure Vessel High Pressure Scram

   Change Allowable Value from ≤ 1054 psig to ≤ 1085 psig.
   Change Analytical Limit from ≤ 1071 psig to ≤ 1101 psig.

2. Main Steam High Flow

   The analytical limit for main steam high flow is based on 140% of the uprated steam flow condition.
   Change Allowable Value from ≤ 101 psid to ≤ 116 psid for Unit 1 and from ≤ 124 psid to ≤ 145 psid for Unit 2.

3. Turbine First-Stage Scram Bypass Pressure

   The turbine first stage pressure setpoint was changed to reflect the expected pressure at the new 30% power point.

4. ATWS Recirculation Pump Trip Reactor Vessel Pressure - High

   Change Allowable Value from ≤ 1095 psig to ≤ 1175 psig.
   Change Analytical Limit from ≤ 1150 psig (generic value) to ≤ 1180 psig.

The licensee's submittal dated January 13, 1995, did not provide information regarding the methodology used for the changes in instrument setpoint calculations. By letter dated March 10, 1995, the NRC staff requested additional information regarding the setpoint methodology. The licensee, by letter dated April 5, 1995, provided responses to the NRC staff's request and confirmed that a plant-specific methodology similar to that in GE Licensing Topical Report NEDC-31336, "General Electric Setpoint Methodology" was used. The licensee, in its letter, also confirmed that the methodology similar to the NEDC-31336 generic methodology has been used for instrument setpoint calculations at other BWR plants.

The proposed setpoint changes resulting from the power uprate are intended to maintain the existing margins between operating conditions and the reactor trip setpoints and do not significantly increase the likelihood of a false trip nor failure to trip upon demand. Therefore, the existing licensing basis is not affected by the setpoint changes to accommodate the power uprate.

Based on the review of the licensee's submittals, the NRC staff concludes that the setpoint methodology and the resulting setpoint changes incorporated into the TS for the power uprate are consistent with the Hatch Units 1 and 2 licensing basis and are, therefore, acceptable.

3.22 Radiation Levels

The licensee evaluated the effects of power uprate on the radiation levels in the plant during normal operation, anticipated operational occurrences, and accident conditions. The licensee concluded that radiation levels in the plant may increase slightly due to the increased reactor operating power level.

Normal plant operation and post-operational radiation levels are not expected to increase by more than the increase in licensed power (5%). Any such increase is bounded by the conservatism, or margin, in the original plant design and analysis. Also, individual exposures to plant workers will be maintained within regulatory limits and as low as reasonably achievable (ALARA) by the existing plant radiation protection program. Procedural controls can compensate for the nominal increase in radiation levels.
The offsite doses associated with normal operation and anticipated operational occurrences are not significantly affected by operation at the uprated power level. The technical specifications limiting the main condenser offgas gross gamma activity release rate will not be changed. In addition, no change is proposed to the radiological effluent technical specifications that insure radiation doses to the public are below the limits of 10 CFR Part 20 and Appendix I to 10 CFR Part 50.

On the basis of its review, the staff concludes that no significant adverse effect or increase in radiation levels will result onsite or offsite from the proposed power uprate.

3.23 Radiological Consequences - Design Basis Accidents

In an enclosure to its January 13, 1995, letter, the licensee provided an analysis of the impact on the radiological consequences of operating at the proposed uprated power for a spectrum of design basis accidents (DBA). The licensee stated that this analysis was performed for Unit 2 using the guidance in RG 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences for a Loss-of-Coolant Accident for Boiling Water Reactors," at 102% of the uprated power level (2609 MWt), consistent with RG 1.49. Unit 2 was used as the bounding case since it has the higher allowable Main Steam Isolation Valve (MSIV) leakage.

By letter dated March 17, 1994 (Reference 9), the Commission approved Amendment No. 132 to the Hatch Unit 2 operating license that increased the allowable Unit 2 MSIV leakage from 11.5 standard cubic feet per hour (scfh) for any one MSIV to 100 scfh for any one, with a total maximum leakage of 250 scfh for all MSIVs. A comparison of the DBA radiological consequences calculated by the licensee in Reference 1 to the consequences calculated by the NRC staff included in the Unit 2 MSIV approval indicates the licensee's results are significantly lower than the staff's. An investigation into this discrepancy indicated that it was caused by the differences in the methods used by the licensee and staff for calculating the atmospheric dispersion factors (X/Q) used in the dose calculations. The licensee used the method outlined in NUREG/CR-5055. The acceptability of the method outlined in this contractor report is still under review by the NRC staff. The staff's analysis used to approve the Unit 2 MSIV leakage used X/Q values from the original Hatch Final Safety Analysis Report (calculated by the Murphy-Campe method), which are part of the licensing basis of the facility.

The staff independently evaluated the radiological consequences of the uprated power on the applicable design basis accidents, using methods and assumptions consistent with the staff's analysis in Reference 9. The events evaluated were the loss-of-coolant accident (LOCA), a control rod drop accident (CRDA), and the fuel handling accident (FHA). The whole body and thyroid dose were calculated for the exclusion area boundary (EAB), and the low population zone (LPZ). In addition, doses to operators in the main control room (MCR) during a LOCA were calculated. The doses resulting from the accidents analyzed are listed below with the applicable acceptance criteria.

DBA Radiological Consequences

	DOSE (rem)	Reference Acceptance Criteria
LOCA		
EAB:		
Whole Body	<2	25
Thyroid	62	300
LPZ:		
Whole Body	<2	25
Thyroid	274	300
MCR:		
Whole Body	<1	5
Thyroid	30	30
FHA		
EAB:		
Whole Body	<1	6
Thyroid	30	75
LPZ:		
Whole Body	<1	6
Thyroid	30	75
CRDA		
EAB:		
Whole Body	<1	6
Thyroid	1	75
LPZ:		
Whole Body	<1	6
Thyroid	3	75

The control room operator doses were estimated using the methodology given in the Standard Review Plan (SRP), Section 6.4. These computed offsite and control room operator doses are within the acceptance criteria given in SRP, Section 15.7.4 and General Design Criterion (GDC) 19, respectively.

Based on the review of the information submitted by the licensee, the NRC staff concludes that the offsite radiological consequences and control room operator doses at the uprated power level of 2558 MWt will continue to remain within the design criteria in 10 CFR Part 100 and 10 CFR Part 50, Appendix A, GDC 19. Therefore, the staff concludes that the radiological consequences associated with the licensee's request to uprate the authorized maximum reactor core power level by 5% to 2558 MWt from its current limit of 2436 MWt are acceptable.

3.24 Human Factors

The NRC staff reviewed the licensee's January 13, 1995, submittal regarding the proposed power uprate and determined that additional information was needed. By letter dated March 10, 1995, the staff requested additional information regarding changes to operator actions and action times, operator reliabilities, and emergency operating procedures.

By letter dated April 5, 1995, GPC, in response to the staff's request, stated that power uprate would not change the type, scope, and nature of operator actions needed for accident mitigation and that it would not require any new operator actions. The licensee stated that the power uprate would result in a slightly shorter response time for some operator actions. The licensee added that the change in response time is not significant, that the accident mitigation strategy of the emergency operating procedures would not change, and that the operating crew will still be able to successfully implement emergency operating actions. The licensee stated that changes to emergency and abnormal operating procedures required for the power uprate will only include revision to previously defined numerical values (e.g., setpoint values). The licensee compared the potential impact of the power uprate on operator actions modeled in the Individual Plant Examination with the General Electric generic analysis and concluded that the power uprate will not significantly impact operator reliability or performance.

On the basis of the review of the licensee's submittals, the NRC staff concludes that the comments associated with the proposed Hatch Units 1 and 2 power uprate have been satisfactorily addressed. The staff further concludes that the power uprate should not adversely affect operator actions or operator reliability.

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

Pursuant to 10 CFR 51.21, 51.32, and 51.35, an Environmental Assessment and Finding of No Significant Impact was published in the Federal Register on July 27, 1995 (60 FR 38593).

Accordingly, based on the Environmental Assessment, the Commission has determined that issuance of this amendment will not have a significant effect on the quality or the human environment.

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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REFERENCES

1. Letter, J. T. Beckham, Jr., Georgia Power Company, to USNRC, "Edwin I. Hatch Plant, Request for License Amendment: Power Uprate Operation," January 13, 1995; and Responses to Requests for Additional Information, dated April 5, 1995, and June 20, 1995.

2. GE Nuclear Energy, "Generic Guidelines For General Electric Boiling Water Reactor Power Uprate," Licensing Topical Report NEDO-31897, Class I (Non-Proprietary), February 1992; and NEDC-31897P-A, Class III (Proprietary), May 1992.

3. Letter, William T. Russell, NRC, to Patrick W. Marriott, GE, "Staff Position Concerning General Electric Boiling Water Reactor Power Uprate Program," September 30, 1991.

4. GE Nuclear Energy, "Generic Evaluations of General Electric Boiling Water Reactor Power Uprate," Licensing Topical Report NEDC-31984P, Class III (Proprietary), July 1991; NEDO-31984, Class I (Non - Proprietary), March 1992; and Supplements 1 and 2.

5. General Electric Company, NEDC-32405P, "Power Uprate Safety Analysis Report For Edwin I. Hatch Plant Units 1 & 2," Class III, December 1994 (Proprietary).

6. Georgia Power Company letter to NRC, HL-4781, "Edwin I. Hatch Nuclear Plant, Response to Second Request for Additional Information Regarding Core Shroud Modification," dated February 20, 1995.

7. Georgia Power Company letter to NRC, HL-4865, "Edwin I. Hatch Nuclear Plant, Response to Second Request for Additional Information - Power Uprate Submittal," dated June 20, 1995.

8. Georgia Power Company letter to NRC, HL-4812, "Edwin I. Hatch Nuclear Plant, Response to Request for Additional Information - Power Uprate Submittal," dated April 5, 1995.

9. Letter dated March 17, 1994, from Kahtan N. Jabbour, Hatch Project Manager, Office of Nuclear Reactor Regulation, NRC, to J. T. Beckham, Vice President - Plant Hatch, Georgia Company: Issuance of Amendment No. 132 to Facility Operating License NPF-5.