CP&L
A Progress Energy Company

John S. Keenan
Vice President
Brunswick Nuclear Plant

MAR 1 2 2002

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TSC-2001-09

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

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING REQUEST FOR LICENSE AMENDMENTS - EXTENDED POWER UPRATE (NRC TAC NOS. MB2700 AND MB2701)

Ladies and Gentlemen:

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt. Subsequently, on December 11, 2001, the NRC provided an electronic version of a request for additional information (RAI) associated with the Reactor Systems Branch's review of the extended power uprate amendment request. This RAI also includes questions resulting from the NRC's audit of General Electric (GE) Company, conducted December 3 through 7, 2001. The response to this RAI is provided in Enclosure 1.

Enclosure 1 contains information that GE considers to be proprietary. The portion of the text containing the proprietary information is identified with vertical sidebars in the right margin. GE requests that the proprietary information in this response be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4), 2.970(a)(4), and 2.790(d)(1). Affidavits supporting this request are provided in Enclosure 2. A non-proprietary (i.e., redacted) version of the response is provided in Enclosure 3.

On June 26, 2001, CP&L submitted a license amendment request for BSEP Units 1 and 2 (i.e., Serial: BSEP 01-0076, TAC Numbers MB2321 and MB2322) to revise the BSEP thermal-hydraulic stability long-term solution from the existing Boiling Water Reactor Owners' Group (BWROG) Enhanced Option I-A solution to the BWROG Option III

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A001

solution. NRC Questions 5-22, 5-23, and 5-24 are applicable to the June 26, 2001, amendment request.

Please refer any questions regarding this submittal to Mr. David C. DiCello, Manager - Regulatory Affairs, at (910) 457-2235.

Sincerely,

CJ Gannon for J.S. Keenan

John S. Keenan

MAT/mat

Enclosure:

1. Response to Request for Additional Information (RAI) 5 - **Proprietary**
2. General Electric Affidavit of Proprietary Information
3. Non-Proprietary Version of Response to Request for Additional Information (RAI) 5

C. J. Gannon, having been first duly sworn, did depose and say that the information contained herein is true and correct to the best of his information, knowledge and belief; and the sources of his information are officers, employees, and agents of Carolina Power & Light Company.

Kenneth M. Nicely
Notary (Seal)

My commission expires: MAY 18, 2003

cc: **(with Enclosures except as noted)**

U. S. Nuclear Regulatory Commission, Region II
ATTN: Mr. Luis A. Reyes, Regional Administrator
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
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U. S. Nuclear Regulatory Commission
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U. S. Nuclear Regulatory Commission **(Electronic Copy Only)**
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11555 Rockville Pike
Rockville, MD 20852-2738

U. S. Nuclear Regulatory Commission
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Ms. Jo A. Sanford **(w/o Enclosure 1)**
Chair - North Carolina Utilities Commission
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Mr. Mel Fry **(w/o Enclosure 1)**
Director - Division of Radiation Protection
North Carolina Department of Environment and Natural Resources
3825 Barrett Drive
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ENCLOSURE 2

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING
REQUEST FOR LICENSE AMENDMENTS - EXTENDED POWER UPRATE
(NRC TAC NOS. MB2700 AND MB2701)

General Electric Affidavit of Proprietary Information

General Electric Company

AFFIDAVIT

I, **George B. Stramback,** being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 2 to letter GE-KB0-AEP-325P, *Response to NRC Request for Additional Information (RAI) –RAIs 5-1, 5-3, 5-7, 5-9, and 5-17*, dated December 21, 2001. The proprietary information in Attachment 2 (*GE-KB0-AEP-326P, GE Responses to NRC RAIs 5-1, 5-3, 5-7, 5-9, and 5-17a,* (GE Company Proprietary)), is identified by bars marked in the margin adjacent to the specific material.

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-33039P, *Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated August 2001, which contains detailed results of analytical models, methods and processes,

including computer codes, which GE has developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 20th day of December 2001.

George B. Stramback
General Electric Company

Subscribed and sworn before me this 20th day of DECEMBER 2001.

Notary Public, State of California

ANNA HANLIN
Commission # 1184507
Notary Public - California
Santa Clara County
My Comm. Expires Jun 19, 2002

General Electric Company

AFFIDAVIT

I, **David J. Robare,** being duly sworn, depose and state as follows:

(1) I am Technical Projects Manager, Technical Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GE letter GE-KBO-AEP-332P, Carl Hinds (GE) to Bob Kitchen (Brunswick Unit 1 and Unit 2) , *Response to NRC Request for Additional Information (RAI) -5-3, 5-10(a), 5-11, 5-20, 5-25(b), 5-26, 5-27 and 11-4*, dated January 17, 2002. The proprietary information is delineated by a bar marked in the margin.

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

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(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains responses containing or based on detailed results of analytical models, methods and processes, including computer codes for BWRs.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

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STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

David J. Robare, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 17TH day of JANUARY 2002.

David J. Robare
General Electric Company

Subscribed and sworn before me this 17TH day of JANUARY 2002.

Notary Public, State of California

ANNA HANLIN
Commission # 1184507
Notary Public - California
Santa Clara County
My Comm. Expires Jun 19, 2002

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STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

David J. Robare, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 11TH day of JANUARY 2002.

David J. Robare
David J. Robare
General Electric Company

Subscribed and sworn before me this 11TH day of January 2002.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Terry J. Morgan
Notary Public, State of California

ENCLOSURE 3

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING
REQUEST FOR LICENSE AMENDMENTS - EXTENDED POWER UPRATE
(NRC TAC NOS. MB2700 AND MB2701)

Non-Proprietary Version of Response to Request for Additional Information (RAI) 5

Background

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications (TSs) for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt. Subsequently, on December 11, 2001, the NRC provided an electronic version of a RAI associated with the Reactor Systems Branch's review of the extended power uprate (EPU) amendment request. This RAI also includes questions resulting from the NRC's audit of General Electric Company, conducted December 3 through 7, 2001. The responses to this RAI follow.

LOCA Analysis

NRC Question 5-1

For the CPPU ECCS/LOCA approach, specify and explain; (i) the number of breaks analyzed for the large and small breaks, (ii) what power level are all of the resident fuel ECCS-LOCA analysis performed, and (iii) why does the limiting small break location change for the EPU.

Response to Question 5-1

(i) [REDACTED]

(ii) BSEP has two fuel types: GE13 and GE14. The GE13 was analyzed at a core power level of 2679 MWt (i.e., 110% of original licensed thermal power) in support of the previous 105% power uprate project. The GE14 was analyzed at a core power level of 2679 MWt for the new fuel introduction and at the CPPU core power level of 2923 MWt nominal; 2982 MWt for the Appendix K.

(iii) In the Emergency Core Cooling System (ECCS) / Loss-of-Coolant Accident (LOCA) analyses, the limiting single failure in the small break region is the failure that eliminates the high pressure ECCS. With no high pressure ECCS makeup, the vessel must be depressurized in order for the low pressure ECCS to inject and restore core cooling. For a given set of ECCS performance characteristics, the system response and fuel heatup for the small break spectrum is determined by a combination of steam generation, depressurization capacity, and break size. The worst small break is determined by the combination of these parameters that results in the longest core uncovery time. The break plays two parts in the system response. First, the break drains the liquid from the vessel and uncovers the core. Once the liquid level in the vessel drops below the elevation of the break, the break aids in the vessel depressurization and subsequent core reflooding.

In order to depressurize the vessel, the steam generated by the decay heat in the core and the steam generated due to flashing during depressurization must be removed through the Automatic Depressurization System (ADS) and through the break. EPU increases the steam generated by the decay heat in the core. Since the ADS capacity is fixed, it takes longer for the vessel to depressurize through the ADS valves at EPU for a given size break. However, since the vessel pressure stays higher for a longer period of time, the liquid flow out the break is higher. The core may uncover earlier, which may lead to a higher PCT, but the break also uncovers earlier, which leads to earlier ECCS injection and may result in a lower PCT. Because EPU increases the steam generated by the decay heat in the core, EPU alters the worst break combination steam generation and depressurization capacity, resulting in a shift in the limiting small break size.

NRC Question 5-2

To understand the basis for the ECCS-LOCA approach, explain what parameters affect the ECCS-LOCA fuel / system response for the blowdown and the reflood phase for the DBA and small break LOCA. Also, explain why the small break PCT is increasing for the EPU conditions.

Response to Question 5-2

The double-ended recirculation line break presents the most severe challenge to the reactor and ECCS and usually results in the highest PCTs. Immediately after the postulated double-ended recirculation line break, vessel pressure and core flow begin to decrease. The initial pressure response is governed by the closure of the turbine control valves in response to the drop in steamline flow and the relative values of energy added to the system by decay heat and energy removed from the system by the initial blowdown of fluid from the downcomer. The initial core flow decrease is rapid because the recirculation pump in the broken loop loses suction and ceases to pump almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds. When the jet pump inlets uncover, the flow connection between the downcomer and core region is broken and the core flow essentially stops. When the recirculation pump suction nozzle uncovers, the energy release rate from the break increases significantly and the vessel rapidly depressurizes. As a result of the increased rate of vessel pressure loss, the initially subcooled water in the lower plenum saturates and flashes up through the core, increasing the core flow. This lower plenum flashing continues at a reduced rate for the next several seconds.

Heat transfer rates on the fuel cladding during the early stages of the blowdown are governed primarily by the core flow response. The initial decrease in core flow may cause boiling transition to occur in the upper portion of the fuel bundle. Nucleate boiling continues at the high power plane until shortly after the jet pump uncovery.

Boiling transition follows shortly after the core flow loss that results from jet pump uncovery. Film boiling or transition boiling heat transfer rates then apply. The cladding temperature rapidly increases with the drop in heat transfer, driven by the stored energy in the fuel. This initial heatup forms the first peak in the cladding temperature response. The heat transfer rate increases during the lower plenum flashing period, then slowly decreases until the core uncovers. At that time, steam cooling provides convective heat transfer.

The water level inside the shroud remains high during the early stages of the blowdown due to flashing of the water inside the core. When the flashing subsides, the level inside the shroud decreases to uncover the core. At the end of the blowdown period, the vessel is essentially empty, with only a few feet of water remaining in the lower plenum. The ECCS, initiated at the beginning of the event by high drywell pressure and/or low reactor water level trips, begin injecting at the end of the blowdown. Flow from the ECCS fills the lower plenum. Once the lower plenum is filled, the core is rapidly recovered.

The cladding temperature at the high power plane decreases initially because the nucleate boiling is maintained, the heat input decreases and the sink temperature decreases. A rapid, short duration cladding heatup follows the boiling transition and the cladding temperature approaches that of the fuel. When the core uncovers, the subsequent cladding heatup is slower, being governed by decay heat and steam cooling. Finally, the heatup is terminated when the core is recovered by the accumulation of ECCS water.

As evidenced by the small reported PCT impacts, EPU has very little effect on the fuel and system response to a large break LOCA. The local fuel conditions are not significantly changed with CPPU because the hot bundle operation is still constrained by the same operating thermal limits (i.e., Minimum Critical Power Ratio (MCPR), Linear Heat Generation Rate (LHGR), and Maximum Average Planar Linear Heat Generation Rate (MAPLHGR)). The power in the average channel increases in proportion to the core power increase. As the average channel power increases with power uprate, the fraction of the flow passing through the hot channel increases. The increased flow keeps the cladding temperature from increasing with CPPU. During the reflooding phase, the additional steam generated by the higher core decay power is easily vented through the break. Therefore, EPU does not affect the reflooding phase of the event or the determination of the limiting single failure.

The response to small breaks is less severe than the full sized recirculation line break. The vessel pressure remains high and stabilizes at the turbine inlet pressure setpoint or in the Safety Relief Valve (SRV) range, depending on whether or not the Main Steam Isolation Valves (MSIVs) have closed. The water level in the vessel slowly falls as inventory is lost out through the break. If the break is small enough, the high pressure ECCS can replace the lost inventory and maintain the vessel level. If the high pressure ECCS is unavailable or cannot maintain the level, the ADS is initiated on low reactor water level. The ADS opens selected SRVs to rapidly depressurize the vessel, allowing the low pressure ECCS to inject and reflood the core.

The cladding temperature response for the small break is less severe than for the full-sized recirculation line break. The core flow coastdown is gradual and nucleate boiling is maintained until the core uncovers. This allows all the stored energy to be removed from the fuel and there is no first peak heatup. Once the core uncovers, decay heat and steam cooling govern the heatup. The heatup is terminated when the core is recovered by the accumulation of ECCS water.

The small break PCT increases for EPU conditions because the EPU increases the steam generated by the decay heat in the core. Since the ADS capacity is fixed, it takes longer for the vessel to depressurize through the ADS valves and break. This longer depressurization time results in a longer period of core uncovery and higher core heatup.

NRC Question 5-3

The Brunswick Units 1 and 2 ECCS-LOCA performance evaluations are based on the CPPU approach. Therefore, the limiting fuel type for the ECCS-LOCA analysis is determined by comparing the PCTs for all of the resident fuel at the current rated thermal power. The ECCS-

LOCA analysis is performed only for the limiting fuel at the extended power uprate levels. For the Brunswick Units 1 and 2 resident fuel (GE13 and GE14), the PCTs calculated at the CRTP are close. Explain if experience with other EPU evaluations indicate that the ECCS-LOCA response of the GE13 and GE14 fuel are similar or close? For Brunswick, justify why it is not necessary to analyze the GE13 fuel at the EPU power level. Discuss what criteria, if any, is used, in terms of ΔPCT, in establishing the limiting fuel. What is the basis of this criteria.

PCT Description	GE13 at CRTP	GE14 at CRTP
Nominal	1043	1052
Appendix K	1497	1537
Licensing Basis PCT	1520	1560
Estimated Upper Bound PCT (95% Prob PCT)	1460	1490

Response to Question 5-3

[REDACTED]

The BSEP upper bound and licensing basis PCTs for both GE13 and GE14, at current rated thermal power (CRTP), were calculated using the SAFER/GESTR-LOCA methodology. Detailed calculations were performed for each fuel type in order to determine the plant variable uncertainty adder terms used in the upper bound and licensing basis PCTs. [REDACTED]

Based on the results from the GE14 and updated GE13 calculations at CRTP, GE14 was selected as the limiting fuel type to be analyzed for EPU. [REDACTED]

NRC Question 5-4

The ECCS-LOCA analysis is based on Unit 2, and the EPU core design and transient analysis are based on Unit 1. Explain why the Unit 2 ECCS/LOCA analysis bounds Unit 1.

Response to Question 5-4

The BSEP Unit 2 ECCS-LOCA analysis bounds BSEP Unit 1 because of the relevant plant systems, including the ADS systems, are extremely similar except for the difference in the side entry orifice sizes for the two units. This effect is independent of the extended power uprate. There is less steady-state flow to the hot channel for BSEP Unit 2 due to the tighter orifice size. The lower initial flow predicted for the BSEP Unit 2 hot bundle causes this bundle to be in an initial state that is closer to boiling transition. This is because boiling transition is a function of power, flow, and fluid conditions. Given that both bundles have the same power and roughly the same fluid conditions (i.e., thermodynamic properties), the bundle with the lowest flow will be closer to boiling transition. The BSEP Unit 2 hot bundle will experience an earlier boiling transition that potentially will penetrate deeper into the bundle. Less stored energy is removed from the fuel due to the earlier boiling transition. This results in a higher first peak PCT. The second peak PCT can also be increased by the earlier boiling transition because the fuel heatup following uncovery begins at a higher temperature. This effect was quantified with the initial SAFER/GESTR-LOCA analysis of record for BSEP. The Licensing Basis PCT was seen to be 4 degrees F lower for Unit 1, and the Upper Bound PCT was 37 degrees F lower for Unit 1, compared to Unit 2.

The EPU equilibrium reload core design uses only GE14 fuel, which is replacing the GE13 fuel currently used in both BSEP units. GE14 fuel was first introduced in Unit 2 in the last reload. The ECCS-LOCA analysis to support introduction of the GE14 fuel was performed for Unit 2 to support the current power rating of 2558 MWt. This new fuel introduction analysis bounds the introduction of GE14 into Unit 1 in the upcoming Cycle 14 under the existing 2558 MWt power rating, as explained above.

To support extended power uprate, additional analyses were performed for the 2923 MWt power level for Unit 2 based on the GE14 equilibrium core. These analyses likewise are bounding for the mid-cycle Unit 1 and BOC16 Unit 2 partial uprates, and as well as for the full EPU equilibrium condition.

NRC Question 5-5

Since Brunswick Units 1 and 2 are also licensed for 1 ADS OOS and the ECCS-LOCA analysis does not assume HPCI, confirm that the reported GE13 and GE14 PCTs are based on 2 ADS failures (1 ADS OOS and 1 ADS single failure).

Response to Question 5-5

The BSEP ECCS-LOCA analyses used five of the seven total ADS valves.

NRC Question 5-6

The SRLR reports an error of +10°F for the GE 13 fuel. Was this value incorporated into the reported PCT for the GE13?

Response to Question 5-6

The licensing basis PCT reported in the Supplemental Reload Licensing Report (SRLR) for GE13 is 1710°F. The +10°F error must be added to this value. The most recent 10 CFR 50.46 report for BSEP was submitted to the NRC on July 11, 2001 (i.e., Serial: BSEP 01-0083).

The +10°F error is not applicable to the GE13 reanalysis that was performed to demonstrate that GE14 is the limiting fuel type.

Transient Analysis

NRC Question 5-7

Are the Unit 1, Cycle 14 transient analyses based on the EPU conditions? If so, explain why the ΔCPR is lower for the EPU conditions analyzed in Cycle 14 in comparison with Cycle 13.

Response to Question 5-7

[REDACTED]

NRC Question 5-8

The ELTR1/2 and supplement require that MSIVF and TTw/oBP be analyzed for the ASME overpressure transient. However, for Brunswick only the MSIVF was analyzed. Confirm that

this is a deviation from the requirements in ELTRs and justify why only the MSIVF needs to be analyzed.

Response to Question 5-8

Section 5.5.1.4 of ELTR1 states that the worst transient event with failure of the first scram signal is evaluated for EPU, which is usually the MSIV closure with position switch scram failure. Turbine Trip, Bypass Failure, with Scram on High Flux - Failure of Direct Scram (TTNBPF) was included in ELTR1 Table E-1 to reconfirm that the MSIV Closure with Scram on High Flux - Failure of Direct Scram (MSIVF) event remains the worst case under EPU conditions.

Subsequent to ELTR1, the NRC, in its letter dated September 14, 1998, approved NEDC-32523P, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," commonly referred to as ELTR2. Section 3.8 of the accompanying Safety Evaluation (SE) for ELTR2 states that the closure of all MSIVs is more severe than the turbine/generator trip with coincident failure of the turbine steam bypass system valves at EPU conditions when credit is taken for the first backup scram. The SE further acknowledges that the closure of all MSIVs event is used as the American Society of Mechanical Engineers (ASME) overpressure protection basis event. The analysis of closure of all MSIVs event is discussed in Section 3.2 of the BSEP Power Uprate Safety Analysis Report (PUSAR).

Consequently, the analysis of the TTNBPF event is not required for the BSEP EPU.

NRC Question 5-9

How is it verified that previous non-limiting transients would not become a limiting transient due to the more challenging EPU reload core designs.

Response to Question 5-9

[REDACTED]

EPU Core Design

NRC Question 5-10

a. Describe the core design changes required to achieve the EPU power level. Include in your discussion, (1) if the GE 14 bundle enrichment would increase, (2) whether the core radial

power distribution and bundle radial power distribution would change relative to the current core design, and (3) if the number of high powered bundles would increase relative to the current core design.

b. What would be the planned implementation of the EPU for both units. Would Unit 1 achieve the EPU power levels for Cycle 14?

Response to Question 5-10a

EPU, as planned for BSEP, (i.e., without changing cycle length or load factors) requires the core to produce more energy during the cycle. In order to achieve this energy production, both bundle enrichment and the fresh batch size are increased. [REDACTED]

Due to the increased enrichment and redesign of gadolinia rod placement, the bundle radial power peaking (i.e., also known as rod peaking) is generally increased, especially near beginning-of-life. The effect of the core re-design on the core power distribution is complicated. Power distributions change dramatically throughout a cycle as control blades are moved and axial power shapes shift. This dynamic situation exists with or without EPU, so it is difficult to isolate the quantitative impact of the EPU. However, the average bundle power increases and the thermal limits remain the same. Consequently a flatter, less peaked radial power profile must be designed in order to maintain similar margin to thermal limits. This does not mean that the uprated core is always flatter than the current core. Because the amount of excess thermal margin varies throughout any reload cycle, there may be more margin at a given exposure for pre-EPU conditions and, therefore, a flatter power distribution. Due to the effect of gadolinia burnable poison, bundles reach their highest power levels during the latter part of their first cycle of operation. Increasing the batch size from approximately 212 to about 256 bundles, therefore, results in more high power bundles relative to the current core design.

Response to Question 5-10b

As discussed in the cover letter and Enclosure 2 of CP&L's extended power uprate (EPU) amendment request (Serial: BSEP 01-0086, dated August 9, 2001), CP&L is planning to implement EPU on each unit in two stages. To support the EPU, modifications will be implemented during the next two refueling outages on each unit (i.e., refueling outages beginning in March 2002 (B114R1) and March 2004 (B115R1) for Unit 1 and March 2003 (B216R1) and March 2005 (B217R1) for Unit 2). Modifications performed during the first refueling outage on each unit will support an increase in rated thermal power (RTP). Modifications performed during the second refueling outage should allow the units to achieve the full uprate to 2923 MWt.

Since modifications performed during the first refueling outage on each unit will support an increase in RTP, Unit 1 will be in the position to implement the first uprate at the completion of the March 2002, refueling outage. Therefore, Unit 1 would achieve EPU operation during Cycle 14, after NRC issuance of the proposed license amendment.

ATWS and SLC

NRC Question 5-11

The SLC cold shutdown boron concentration may need to be changed from 660 ppm to 720 ppm, however an amendment requesting increase in the SLC concentration has not been submitted. Explain the boron concentration requirement used in the Unit 1 Cycle 14 reload analysis. Specify the schedule for a license amendment to support the cold shutdown boron concentration change. Please explain why the cold shutdown boron concentration may need to change, but the hot shutdown boron concentration is unchanged.

Response to Question 5-11

The calculated Standby Liquid Control (SLC) system cold shutdown margin is documented to meet design requirements at the existing 660 ppm boron concentration in the B1C14 Supplemental Reload Licensing Report. [REDACTED]

The cold shutdown boron concentration (CSBC) requirements are driven less by the plant's rated power output than by the total reactivity requirements for the cycle (i.e., total energy produced), and the neutron energy spectrum at cold conditions. The cycle energy production is influenced even more by capacity factor, outage length, and cycle duration than by EPU, such that SLC system boron has been closely monitored for years independent of the EPU project. The use of more highly enriched GE14 fuel, in support of EPU, exacerbates the situation by hardening the neutron spectrum and reducing boron reactivity worth.

The overall effect is such that, with a single reload of GE14 fuel in conjunction with BSEP's planned EPU conditions, the 660 ppm CSBC limit remains effective; however, with the second reload of GE14, an increase in CSBC is required.

The first reload of GE14 fuel in BSEP Unit 1 occurs during the initial EPU uprate cycle in 2002. BSEP Unit 2 was loaded with one reload of GE14 in advance of EPU, therefore, the February 2003 reload will include the second batch of GE14. To support an associated need date of February 2003 for the CSBC limit, CP&L plans to submit a license amendment request in June 2002.

There is no change in the hot shutdown boron concentration (HSBC) because: (1) it is a generic value that has been conservatively calculated to satisfy Emergency Procedure Guidelines, and (2) the reload design process inherently tends to mitigate the impact on HSBC.

The reason for the conservative generic HSBC requirement is that the ATWS mitigation strategy is directly linked to the assumption used to determine the time required to inject the HSBC. If HSBC is increased, the reactor must wait longer at the flow-stagnation power; which may make the transient worse.

The margin resulting from this conservative HSBC requirement is sufficient to accommodate the impact of the reactivity and spectral effects described above for CSBC. Because the reload design process always includes shutdown margin limits associated with control blades, the reload design inherently must take into account the reactivity requirements to bring the reactor to hot shutdown from the peak reactivity condition at rated power operation. This shutdown requirement is satisfied using similar control blade worths, both before and after EPU. Therefore the reload design process inherently prevents major change in the HSBC requirement.

NRC Question 5-12

Has BNP reviewed Information Notice 2001-13 on SLC relief valve margin? If applicable, what actions are planned to address this issue?

Response to Question 5-12

The original, generic design basis of SLC system was to be able to inject, with one pump, at reactor vessel pressures up to the setpoint of the lowest group of SRVs. As noted in Information Notice (IN) 2001-13, the SLC design was updated, in accordance with 10 CFR 50.62, to address anticipated transient without scram (ATWS) concerns. For both the plant described in the IN 2001-13 (i.e., Susquehanna) and BSEP, this required the SLC design to be modified for simultaneous two pump operation. The increased injection line flow losses required that the system accommodate an increase in pump discharge pressures. The BSEP SLC design has also been updated to reflect higher vessel pressures associated with the 105% uprate.

IN 2001-13 notified licensees of a finding, during a design inspection, where a plant specific ATWS evaluation result in vessel pressures higher than those assumed in the SLC system evaluation. The pressures on the time history charts were close to the analytical limit of the setpoints for SRVs operating in a safety mode.

Pre-EPU BSEP SLC Design Basis

The SLC system design basis was revised during the 105% uprate due to an increase in the SRV setpoints. The assumed reactor vessel pressure of 1130 psig was based on the nominal trip setpoint of the lowest group of SRVs. The resultant SLC pump discharge relief valve margin was found to be adequate.

EPU ATWS Evaluation Background

CP&L has evaluated SLC discharge relief valve margin using the predicted vessel pressures from the ATWS cases that were evaluated as required by ELTR1 section 5.3.4 and Appendix L. As stated in ELTR1, the acceptance criteria for these evaluations were:

- Peak vessel bottom pressure less than ASME service level C limit of 1500 psig.
- Maximum containment pressure and temperature lower than the design pressure and temperature of the containment structure.
- Peak cladding temperature below the 2200 °F requirement of 10CFR50.46.
- Clad oxidation below the requirements of 10CFR50.46.

ELTR1 section L.3.4 provided input parameters guidance as follows:

> Inputs shall be selected consistent with those used in previous ATWS evaluations (Reference 24) except as noted here or justified in the evaluation. In general nominal operating and equipment parameters are utilized for the evaluation of this special situation. Safety/relief valve and recirculation pump trip pressure setpoints will reflect any new values chosen for uprated operation; for overpressure evaluation, current allowances for setpoint drift and uncertainty will be included.
>
> *Justification*
>
> This approach for the ATWS evaluation is consistent with the main body of the accepted basis for ATWS evaluation, as well as incorporating current values of the key parameters most related to power uprate.

The ATWS evaluation for EPU conditions was performed to meet the above acceptance criteria with inputs that were either consistent with or conservative to the above requirements. Note that the only acceptance criteria, with respect to vessel pressure, was associated with the peak pressure that occurs well before SLC initiation. The evaluations were not tailored to assess vessel conditions during the SLC injection phase of the events.

Proposed Methodology for Evaluation of SLC Relief Valve Margin During ATWS Events

The ELTR1 guidance on input assumption for ATWS evaluations clearly states that inputs are generally based on nominal operating and equipment parameters except that current allowances for setpoint drift and uncertainty will be included for the Safety/relief valve and recirculation pump trip pressure setpoints. The allowance for use of some nominal inputs is based on the extremely low probability of an ATWS event. For the evaluation of SLC relief valve discharge margin during an ATWS event, CP&L has determined that the injection line flow loss and pulsation margin should be based on nominal operating values as established by the data from the March 31, 2001 SLC injection into the Unit 2 reactor vessel. If CP&L were required to use

all analytical inputs for evaluation of this aspect of ATWS mitigation capability, this would be contrary to the accepted practices that were in use when NEDE-24222 (Assessment of BWR Mitigation of ATWS, December 1979, Reference 24 of ELTR1) was originally used as the basis for BSEP compliance with 10 CFR 50.62.

Inputs for Evaluation of SLC Relief Valve Margin During ATWS Events

The results of the ATWS evaluations were reviewed to determine the maximum predicted vessel steam dome pressure during postulated SLC injection. Consistent with the requirements of ELTR1 3.7.1.2, the EPU evaluations used an operator action response time of 120 seconds for SLC injection. BSEP has determined that the operator action response time is not expected to be less than 79 seconds. Using the more conservative 79 second operator response time, the peak predicted vessel pressure for SLC injection was determined as follows:

Event	SLC Initiation Symptom (sec)	SLC Start (sec)	Time of Maximum Pressure (sec)	Peak Predicted Pressure (psig)
MSIVC EOC	4	83	89	1194
MSIVC BOC	4	83	94	1191
LOOP EOC	1	80	166	1185
PRFO EOC	23	102	185	1185
PRFO BOC	24	103	225	1184

The MSIVC End of Cycle (EOC) closure case resulted in the highest vessel pressure response during SLC injection. At 29 seconds into this event, the results show total flow capacity of the SRVs (i.e., with 10 of 11 assumed to be operable) greater than the steam generation rate of the core. After this time, pressure will continue to drop until the number of SRV that reseat reduces the SRV capacity to less than the core steam generation rate. The pressure will then increase until SRV(s) reopen. Just prior to the pressure peaks shown above, the results show pressure increasing at a rate of less than 25 psig per second. With a SRVs response time of 0.4 seconds, a maximum pressure overshoot of 10 psig would be expected. With a Technical Specification setpoint limit of 1184.5 psig on the SRV setpoints and a maximum overshot of 10 psig, there is a high level of confidence that the 1194 psig predicted peak at 89 seconds into the MSIC EOC case is conservative and justifiable as the maximum expected vessel steam dome pressure during SLC injection for an ATWS response. Note that the results were not affected by loss of offsite power (LOOP) conditions since BSEP does not use transmitters to control SRV operation.

The SLC pump discharge relief valve is located just above the 83 feet elevation. The SLC injection line travels down, penetrates the vessel at an elevation of approximately 40 feet and then goes back up to an elevation of approximately 48 feet. Although the injection occurs along a section of the sparger below elevation 48 feet, use of this elevation is conservative. With an

injection line temperature of 110 °F and an injection solution specific gravity of 1.07, the elevation change reduces the required SLC discharge pressure by 16 psig.

SLC discharge relief valve margin is only a concern for events where the MSIVs close early the event. With MSIV closure, the turbine driven feedwater pumps are lost and a significant drop in vessel water level occurs. Water level will be assumed to be 2 feet below normal. This is very conservative as the actual water level for each case was predicted to be at least 12 feet below normal by the time the peak predicted pressure occurred. With an assumed water level at an elevation of 78 feet and a conservative temperature of approximately 528 °F, steam dome pressure will be 10 psig above the lower plenum pressure at the 48 foot elevation.

The combined head effect of the injection line and the water above the sparger in the vessel will be assumed to reduce the required SLC discharge pressure by 16 - 10 = 6 psig.

The existing analytical design basis two pump injection line flow loss is 201 psig for two pump injection based on a 1984 GE evaluation. A 1985 evaluation by CP&L indicated that the expected flow loss would be closer to 161 psig. Given the discrepancy, the following actual test data from a March 1, 2001, Unit 2 injection was evaluated.

Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)
3:11:20	145	3:11:42	197	3:12:04	156	3:12:26	177
3:11:21	142	3:11:43	181	3:12:05	162	3:12:27	166
3:11:22	160	3:11:44	166	3:12:06	168	3:12:28	155
3:11:23	178	3:11:45	150	3:12:07	173	3:12:29	144
3:11:24	195	3:11:46	153	3:12:08	179	3:12:30	147
3:11:25	213	3:11:47	155	3:12:09	185	3:12:31	150
3:11:26	212	3:11:48	158	3:12:10	176	3:12:32	153
3:11:27	211	3:11:49	160	3:12:11	167	3:12:33	156
3:11:28	210	3:11:50	163	3:12:12	158	3:12:34	159
3:11:29	209	3:11:51	165	3:12:13	150	3:12:36	165
3:11:30	193	3:11:52	172	3:12:14	153	3:12:37	168
3:11:31	177	3:11:53	179	3:12:15	156	3:12:38	172
3:11:32	161	3:11:54	186	3:12:16	159	3:12:39	176
3:11:33	145	3:11:55	193	3:12:17	162	3:12:40	180
3:11:34	152	3:11:56	188	3:12:18	165	3:12:41	184
3:11:35	160	3:11:57	182	3:12:19	168	3:12:42	178
3:11:36	168	3:11:58	177	3:12:20	172		
3:11:37	176	3:11:59	172	3:12:21	175	Average	182
3:11:38	185	3:12:00	166	3:12:22	178	Max	213
3:11:39	194	3:12:01	161	3:12:23	181	Min	142
3:11:40	203	3:12:02	156	3:12:24	184	Mean	178

Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)	Time	SLC PRESSURE (psig)
3:11:41	212	3:12:03	150	3:12:25	187	Deviation	35

The vessel head was off and the water level was at the 116 foot elevation during the test. With the pump discharge at the 82 foot elevation, 14.7 psig of the results was elevation head and not due to flow resistance.

Instrumentation uncertainty was evaluated:

Transmitter input range	1800	psig
Transmitter output range	40	mA
Max transmitter error from last calibration	0.08	mA
Transmitter uncertainty based on last calibration	3.6	psig
ERFIS max on-scale error from last calibration	2	psig
Total test data uncertainty	5.6	psig

Based on the above test data, the injection line flow loss should be no more than 178 - 14.7 + 5.6 = 169 psi.

The existing SLC system design basis requires that a 30 psig margin for pressure pulsations be available. The actual test data presented above shows a 35 psi deviation from the median value. Although actual ATWS injection would be expected to produce smaller pressure pulsations (a pulsation reducer with an 850 psig to 1000 psig pre-charge is installed on the pump discharge) than those noted during the low pressure test, use of 35 psig is conservative and consistent with the "nominal operating and equipment parameters" terminology of ELTR1.

SLC Discharge Relief Valve Margin Evaluation for ATWS

Given the above, the SLC discharge relief valve margin for ATWS injection is:

Assumed max vessel pressure for SLC injection	1194 psig
Elevation head allowance	-6 psig
Two pump injection line flow loss	169 psig
Resultant pump discharge pressure	1357 psig
SLC discharge relief valve nominal trip setpoint	1450 psig
Relief valve setting tolerance	50 psig
Lowest allowed setting	1400 psig

Available pulsation margin	43 psig
Required pulsation margin	35 psig

Since the pulsation margin is 8 psig more than the required margin, SLC can be considered adequate with respect to ATWS injection capability.

SLC Design Basis Discharge Relief Valve Margin Evaluation

The SLC design basis for non-ATWS events has also been considered. Since use of nominal operating parameters is not appropriate for design basis evaluations of Safety Related systems, the following inputs will be used.

Under non-ATWS conditions, only the low group of SRVs are expected to lift, and the rate of pressure increase just prior to a lift is expected to be very low. Based on the Technical Specification maximum allowed setpoint for this group of SRVs, 1164 psig will be used for vessel pressure.

The SLC pump discharge relief valve to lower plenum head allowance is unchanged at 16 psig.

For non-ATWS events, EOPs require that indicated vessel level be kept between 180 inches and 200 inches where normal indicated level is 187 inches. Water level will conservatively assumed to be 2 feet above normal while SLC is injecting. With an assumed water level at an elevation of 82 feet and a temperature of approximately 528 °F, steam dome pressure will be 11 psig above the lower plenum pressure at the 48 foot elevation.

The combined head effect of the injection line and the water above the sparger in the vessel reduces the required SLC discharge pressure by 16 - 11 = 5 psig.

The existing analytical design basis two pump injection line flow loss is 201 psig for two pump injection based on the 1984 GE evaluation.

The existing SLC system design basis requires that a 30 psig margin for pressure pulsations be available. Based on actual test data, a more conservative 35 psig will be used.

Given the above, the design basis SLC discharge relief valve margin is:

Assumed max vessel pressure for SLC injection	1164 psig
Elevation head allowance	-5 psig
Two pump injection line flow loss	201 psig
Resultant pump discharge pressure	1360 psig
SLC discharge relief valve nominal trip setpoint	1450 psig

Relief valve setting tolerance	50 psig
Lowest allowed setting	1400 psig
Available pulsation margin	40 psig
Required pulsation margin	35 psig

With a pulsation margin of 5 psig more than the required margin, SLC discharge relief valve design margin is positive but small.

Summary

Although the margin for both calculations is small, all of the above inputs have enough individual conservatisms to provide adequate assurance that SLC will perform as required.

NRC Question 5-13

What ATWS events were analyzed at EPU? Verify that for all limiting ATWS events, the SLCS will be able to inject at the analytically assumed time without lifting of the SLCS bypass relief valves, or if the valves lift, verify that they are capable of reseating. For example, will the SLCS be able to inject the required flow rate at the assumed time for the ATWS LOOP event without reaching the nominal SLCS relief valve setpoint?

Response to Question 5-13

As required by ELTR1, the following events are analyzed at EPU:

1. Main Steam Isolation Valve Closure (MSIVC)
2. Pressure Regulator Failure Open – Maximum Steam Demand (PRFO)
3. Loss-of-Offsite Power (LOOP)
4. Inadvertent Opening of a Relief Valve (IORV)

The first two events were analyzed at both Beginning-of-Cycle (BOC) and End-of-Cycle (EOC) conditions. For the first three events, the peak steam dome pressure is between 1450 psig and 1485 psig and it remains above 1200 psig for 20 to 27 seconds. After it falls below 1200 psig, the evaluation shows pressure cycling based on SRV setpoints and reseat values. As discussed in Question 5-12, the SLC pump discharge check valve is not expected to open during injection to the vessel while the vessel pressure cycles based on SRV operation. For these events, ELTR1 guidance required that SLC be assumed to start 120 seconds after the ATWS high pressure trip is received at a steam dome pressure of slightly less than 1200 psig. Since the SLC start is assumed after the pressure is reduced to an acceptable value, pump discharge relief valve operation is not expected for any of these events.

NRC Question 5-14

What is the limiting event for each of the five acceptance criteria in Section 9.3.1 of the PUSAR?

Response to Question 5-14

Parameter	Bounding Event/ Conditions
Peak vessel bottom pressure, psig	PRFO/BOC
Peak suppression pool temperature, °F	MSIVC/EOC
Peak containment pressure, psig	MSIVC/EOC
Peak cladding temperature, °F	PRFO/EOC
Clad oxidation, %	NA

Key:

MSIVC	Main Steamline Isolation Valve Closure
PRFO	Pressure Regulator Failure Open – Maximum Demand
BOC	Beginning-of-Cycle
EOC	End-of-Cycle

NRC Question 5-15

Confirm that the operator response to an ATWS event is not being modified from that described in Section L.3.2. of ELTR1. If the operator requests SLCS actuation before the time assumed in the analysis, will the relief valve lift. Would the relief valves be able to reseat in time before the SLCS injection is required.

Response to Question 5-15

The operator actions on confirmed ATWS symptoms, or during ATWS events described in Section L3.2 of ELTR1, are tripping of feedwater pumps, starting the SLC, maintaining vessel water level near the top of active fuel, and starting the Residual Heat Removal (RHR) system for pool cooling. These actions for EPU have not been modified and are consistent with those during the pre-EPU operation.

As required by ELTR1, plant specific ATWS events were analyzed for EPU. For all events involving the loss of steam flow to the main condenser, the analysis predicts a significant initial pressure increase. For these events, the peak steam dome pressure is between 1450 psig and 1485 psig and it remains above 1194 psig for 20 to 28 seconds. After it falls below 1194 psig, the evaluation shows pressure cycling based on SRV setpoints and reseat values. SLC injection

is not expected to result in discharge relief valve actuation unless steam dome pressure is above 1194 psig. For these events, ELTR1 guidance required that SLC be assumed to start 120 seconds after the ATWS high pressure trip is received at a steam dome pressure of 1147 psig. The results show that peak pressure drops below 1085 psig, prior to the assumed SLC injection.

For a postulated ATWS, plant procedures direct Operators to inject SLC in accordance with Emergency Operating Procedure (EOP) charts. An informal test in the plant simulator found that the required sequence is not expected to result in SLC initiation in less than 79 seconds. Since this is more than double the time required for pressure to return to 1194 psig, SLC pump discharge relief valve opening during an ATWS is not considered credible.

The original, generic design basis of SLC system was to be able to inject, with one pump, at reactor vessel pressures up to the nominal trip setpoint of the SRVs with the lowest trip setpoint. The original relief valve setpoint was selected with sufficient margin such that opening while injecting at the design pressure was not a concern. Therefore, no requirement for the discharge relief valve to reseat after lifting during an injection was established. No component specific design or test data could be found to quantify the actual expected reseat pressure. Generic industry documents for this style of device indicate that the blowdown would typically be between 7% and 20% of the trip setpoint. The SLC pump discharge relief valve must reseat with a blowdown of no more than 14% to close with a vessel steam dome pressure dip to 1085 psig.

Since vessel pressure is expected to return to an acceptable value prior to SLC injection, no changes to the system design or operating procedures are required. As an enhancement, CP&L is considering actions to provide additional confidence that a loss of SLC injection will not be caused by a manual start prior to vessel pressure dropping below 1194 psig. CP&L is attempting to obtain component specific relief valve reseat documentation and updating Operator training material to document SLC limitations is being considered.

SBO

NRC Question 5-16

Specify the amount of CST inventory available for the SBO event and the amount needed to maintain reactor core coolant system inventory. State if the HPC/RCIC could maintain adequate cooling and core coverage above the top of active fuel during the coping period.

Response to Question 5-16

Nominal design reserve Condensate Storage Tank (CST) inventory for High Pressure Coolant Injection (HPCI) operation is currently 100,000 gallons. Inventory usage for station blackout (SBO) after EPU was modeled to be approximately 86,000 gallons based on HPCI control of level between L2 and L8, which maintains adequate cooling and core coverage above the top of the active fuel during the coping period.

Shutdown Cooling Mode

NRC Question 5-17

a. The BNP UFSAR and PUSAR indicate that the RHR shutdown cooling operational criteria of reaching 125°F within 20 hours following shutdown is no longer satisfied but does not provide the EPU estimated time to reach 125°F. Please provide the time along with any other information that quantifies RHR Shutdown Cooling Acceptability.

b. In analyzing the shutdown cooling mode capability for the EPU conditions, please identify any changes made to the codes or the analytical methods used to model the thermal-hydraulic conditions of the core and the coolant system. If any changes to the modeling of the thermal-hydraulic conditions were made, describe what the changes were. Also discuss what quality controls and procedures were used to assure the accuracy of these changes.

Response to Question 5-17a

[REDACTED]

Many BSEP TSs have required actions similar to:

Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

These specifications allow at least 24 hours for the plant to be cooled down from normal operating temperatures to 212°F. Based on operational considerations, CP&L selected 12 hours as an acceptance criterion for the normal SDC analysis for the EPU evaluation. [REDACTED]

Response to Question 5-17b

The SDC capability calculation is performed to evaluate operational considerations related to plant availability and does not require the use of an NRC-approved computer code or a Level 2 computer program. Spreadsheet calculations were used in the BSEP evaluation.

[REDACTED]

Both original and new SDC analysis methods use two nodes of temperature, one for the core exit and the other for the core inlet. For conservatism, the core exit temperature was used as representing the SDC temperature, since it is usually several degrees higher than the core inlet temperature.

The results of the SDC evaluation were independently verified in accordance with the GE Quality Assurance program. The verification included an alternate calculation using a separate SDC spreadsheet.

RCIC

NRC Question 5-18

Is credit taken for RCIC in the "Rod Drop Accident" analysis? Is the reactor water level response bounded by the Loss of Feedwater analysis? Confirm whether or not credit is taken for HPCI in the RDA analysis. If RCIC is inoperable, please explain the scenario.

Response to Question 5-18

No credit is taken for the Reactor Core Isolation Cooling (RCIC) or HPCI systems in the mitigation of the radiological consequences of a Rod Drop Accident (RDA). After the reactor has been scrammed and isolated, inventory makeup to the vessel can be supplied by any of the available normal or safety high-pressure makeup systems, including RCIC or HPCI. The system response for the Loss of Feedwater (LOFW) analysis bounds the system response for the RDA because the reactor scram for the LOFW event is delayed until the level falls to the low-level scram setpoint. If RCIC is inoperable, HPCI has more than sufficient capacity to maintain the reactor vessel inventory. If no high-pressure makeup systems are available, the vessel can be depressurized using the ADS and core cooling will be provided by the low pressure ECCS (i.e., LPCI or Core Spray (CS)).

Updated Final Safety Analysis Report (UFSAR) Chapter 15.0.A, Event 33 and Chapter 15.4.6 discuss a postulated RDA. Chapter 15.4.6 provides a detailed evaluation of postulated cases that bound the expected fuel damage and resultant radiological consequences. Since the initial fuel damage and the source term transport are the only considerations that affect the radiological consequences, these aspects are the only areas where site-specific evaluations have been performed. The UFSAR 15.4.6 section does not describe any of requirements for protection of the reactor core after the scram. Section 15.0.A describes general sequences of plant level responses to postulated events. This section does not, however, reference any site-specific evaluation providing assumed single failures, flow rates, sequence timing, vessel level response or other similar information. This section is more of an explanation as to what equipment could be used than a description of the minimum required equipment for mitigation of accidents. For a RDA without a loss of off site power, it is likely that feedwater would remain available to provide inventory control as the plant is brought to cold shutdown. However, as an accident, it is more appropriate to evaluate the plant requirements assuming:

- a LOOP occurs,
- only safety related equipment is available, and
- an additional single active failure occurs.

Under these assumptions, no credit will be assumed for feedwater, Control Rod Drive (CRD), or RCIC. HPCI is the only remaining method available for providing high-pressure inventory control. With the requirement to assume a single active failure, it is therefore essential that core protection can be provided via depressurizing the vessel such that low-pressure safety systems

can be used. If normal vessel makeup is lost early in the event and if high-pressure makeup can not be achieved via HPCI, RCIC, or CRD, EOP guidance directs rapid depressurization of the vessel such that low-pressure systems can be used for injection. The most applicable site-specific accident evaluation for bounding this event is the main steam line break (MSLB) outside of containment evaluation. The MSLB outside of containment is considered the bounding event for all accidents that result in vessel isolation with no initial makeup because the large break size results in the loss of more inventory than any other postulated event. Since a RDA does not result in any uncontrolled inventory loss, it is fully bounded by the MSLB outside containment event. The BSEP MSLB analysis shows that there is minimal heating of the fuel during a manually initiated, rapid blow down of the vessel at 10 minutes into the MSLB event. If a RDA were to be followed by a manually initiated rapid blow down, the PCT would not be expected to exceed the 631°F estimated peak clad temperature for the MSLB outside containment. With a clad temperature of only 631°F, no further fuel damage would occur. The MSLB evaluation relied on only 5 of 11 SRVs where TSs require that 10 be operable. It also took no credit for HPCI injection and it assumed one LPCI pump and one CS loop failed to inject due to the single failure of one division of emergency power. After reactor vessel depressurization, one loop of RHR could be placed in suppression pool cooling while the remaining loop of CS could continue to provide vessel inventory control. This combination is acceptable for long-term cooling. With no additional fuel damage and with the vessel pressure reduced to less than 100 psig, the use of low-pressure systems would allow core cooling for an extended period with negligible additional activity transport out of the Reactor Building. Therefore, the minimum ECCS equipment needed for mitigation of MSLB outside of containment could also adequately mitigate a RDA. Since the assumptions for the MSLB were sufficient to satisfy the single failure criteria above and beyond having HPCI and RCIC out of service, no credit need be assumed for HPCI or RCIC in mitigation of RDAs.

NRC Question 5-19

Modifications described in GE SIL No. 377 are not incorporated in the RCIC system. Justify why this modification is not necessary at Brunswick. Explain whether the RCIC can inject at the assumed time without RCIC turbine overspeed for all events which require RCIC injection.

Response to Question 5-19

Based on a review and evaluation of RCIC system operating data, the recommended modifications of GE SIL No. 377, "RCIC Startup Transient Improvement With Steam Bypass," do not need to be implemented to support EPU at BSEP. When the reactor vessel pressure was increased as part of the BSEP 105% uprate, it was determined that, based on RCIC operating performance, SIL 377 did not need to be implemented. Although EPU does not increase reactor vessel pressure, this conclusion was re-validated as described below.

As described in Section 3.1 of NEDC-32523P-A (ELTR-2), February 2000, the RCIC design basis performance requirement is based on the Loss of Feedwater Flow (LOFW) transient event. When this event is assumed to occur with closure of the MSIVs, it maximizes the assumed vessel

pressure for RCIC operation. Consistent with ELTR2 Section 3.1.4, the EPU evaluation assumed that the scram and MSIV closure would be initiated at time zero. The resultant pressure response is essentially the same as that for the MSIV closure event where the MSIV limit switches initiate a reactor scram when the MSIVs close to the 90% open position. Based on plant testing and actual events, the peak reactor vessel pressure for this event is limited by actuation of the group of SRVs with the lowest setpoint (i.e., 1130 psig ± 3%, with a TS limit of 1163.9 psig). The peak vessel pressure from the EPU evaluation of this LOFW transient event was 1164 psig. The design basis maximum pressure for RCIC operation (i.e., 1164 psig) was assumed in calculating the maximum expected RCIC speed. No change to the design basis maximum pressure for RCIC operation was required because the low group SRVs still have adequate capacity to handle the steam generation rate associated with decay heat under EPU conditions (i.e., with 3 of the 4 low group SRVs open, capacity is approximately 18% of EPU rated steam flow).

Using data from 14 RCIC starts for vessel injection, it was determined that the initial speed peak for RCIC increases by 2.45 rpm/psig as steam dome pressure increases. Based on this, initial RCIC speed peaks of 4600 rpm, nominal (i.e., reactor vessel pressure at 960 psig), and 5100 rpm, maximum expected value accounting for data scatter and uncertainty with a reactor vessel pressure of 1164 psig, are predicted. With an overspeed trip allowable range of 5513 to 5737 rpm, adequate margin exists such that inadvertent overspeed actuation is not expected.

Fuel Design & Thermal Limits

NRC Question 5-20

Amendment 22 of NEDE-24011-P-A states that loss of fuel rod mechanical integrity will not occur due to excessive cladding pressure loading. Please confirm that the Brunswick EPU core designs conform to the criteria for GE13 and GE14 fuel. Also please provide the fuel rod maximum power LHGRs vs. peak pellet exposure for GE13 and GE14 for Brunswick EPU as compared to the original LHGRs of GE13 and GE14 that were developed according to Amendment 22 of NEDE-24011-P-A.

Response to Question 5-20

Thermal-mechanical analyses of each GE fuel design are performed to demonstrate compliance with the licensing criteria defined in Amendment 22 of "General Electric Standard Application for Reactor Fuel," Licensing Topical Report, NEDE-24011-P-A-14, June 2000 (i.e. GESTAR II). For GE13 and GE14, fuel rod thermal-mechanical compliance is documented in Section 2.2 of "GE13 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDE-32198P, December 1993 and "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDC-32868P Revision 1, September 2000, respectively.

[REDACTED - Two Paragraphs and Two Figures]

NRC Question 5-21

For EPU operation, the fuel rods in a bundle tend to have higher power radially and axially that can result in more oxidation and crud deposition. More crud deposition in bundles can affect the fuel performance during normal operations, and the spent fuel pool cooling and cleaning capability when the fuel discharges. Please explain how the licensee will address this problem.

Response to Question 5-21

The EPU Reactor Water Cleanup (RWCU) Evaluation Task 311 determined that the RWCU system has a removal efficiency of 90%. Since the feedwater flow increases by about 20% for the EPU, it could be expected that the crud in the Reactor Coolant System (RCS) would increase by less than 2%. This could result in a corresponding maximum increase of 2% in the spent fuel pool (SFP), assuming that all residual crud is transported to the SFP.

There is no current operational data from plants that have implemented a 120% EPU which would permit an assessment of the impact of increased crud loading on performance of the Fuel Pool Cooling and Cleanup (FPCC) system. However, because core flow is unchanged, the character and thickness of the equilibrium crud layer on the fuel surface is not expected to change significantly. Thus, the release of crud to the SFP also would not be expected to change significantly. Minor changes in released crud can be accommodated by the Fuel Pool Cleanup system.

Alarms, differential pressure indicators, and flow indicators monitor the condition of the filter-demineralizers, and provide indications of when they need to be backwashed. The ion-exchanger resin is replaced when the pressure drop is excessive or the capacity of the resin is depleted. The potential increase in crud from the EPU may result in slightly more frequent backwashes or replacement of the resins.

The SFP EPU evaluation demonstrated that the FPCC system could adequately handle the increased heat loads and maintains the pool temperature within the design limits. The crud would not affect the heat loads. Since the FPCC system maintains water quality, the heat removal performance of the FPCC system would not be degraded (i.e., no increase in heat exchanger fouling).

It can be concluded that an increase in crud loading on fuel resulting from EPU will have a negligible effect on SFP cooling and clean-up capability. The system will be able to maintain SFP water quality and there will be no effect on the heat removal function. The only effect the crud will have on the system is that there may be an increase in the frequency the filter-demineralizers are backwashed and an increase in the frequency the resins are replaced.

Stability (June 26, 2001 submittal, TAC #s MB2321, MB2322, ML011840415)

NRC Question 5-22

In COLR TS 5.6.5.b.1, the supporting approved methodology for Option III PBDA Setpoint for Function 2.f, OPRM Upscale for TS 3.3.1.1 is NEDE-24011-P-A, which includes NEDO-32465A for DIVOM curve. Please provide the position to be taken after the OPRM system is armed, since there is a Part 21 issue on the DIVOM curve used in NEDO-32465A.

Response to Question 5-22

CP&L's Oscillation Power Range Monitor (OPRM) trip function will be fully operational during the first start-up following installation of the new PRNM system, with related Technical Specifications in place. The PRNM system with OPRM trip function will be installed on Unit 1 during the March 2002, refueling outage. The figure of merit calculation described in GE Nuclear Energy's letters to the NRC dated June 29, 2001, and August 31, 2001, will be performed, during the upcoming refueling outage, to determine if the existing generic regional mode DIVOM curve is applicable for BSEP Unit 1. If the results conclude that the existing DIVOM curve is applicable, then there is assurance that the Option III stability trip system setpoints will provide MCPR Safety Limit protection and CP&L will start-up Unit 1 with the OPRM trip function operable and enabled.

However, if the results of the figure of merit calculation conclude that the existing DIVOM curve is not applicable for BSEP Unit 1, CP&L will start-up with the OPRM trip function enabled but declared inoperable. As a compensatory action, an alternate method to detect and suppress thermal hydraulic instability oscillations will be implemented, as described in proposed Technical Specification 3.3.1.1, Condition I. If the figure of merit calculation demonstrates that the generic regional mode DIVOM curve is applicable for certain parts of the operating cycle, then the OPRM function will be considered operable only during those times when the generic curve bounds BSEP operation. The OPRM trip function will remain enabled but declared inoperable at all times when BSEP operation is not bounded by the generic analysis. Historically, a decade of plant operation using the alternate method to detect and suppress thermal hydraulic instability oscillations has not resulted in any thermal hydraulic instability events. By maintaining the OPRM trip enabled even if the setpoints do not meet the licensing criteria for MCPR Safety Limit protection, additional protection of instability events is provided. The OPRM would scram the plant early in an instability event, such that even if the MCPR limit were exceeded, significant fuel damage would be unlikely. The periodic rewetting of the fuel should provide adequate heat transfer beyond the time when an OPRM scram is completed. By letter dated August 31, 2001, GE Nuclear Energy provided final information concerning the non-conservative reload licensing calculations for stability Option III detect and suppress trip systems. As defined in that letter, BSEP Units 1 and 2 are Category 2 plants, and CP&L's implementation strategy, as described above, is consistent with the third resolution option for Category 2 plants (i.e., implement the system with a non-conservative setpoint and immediately declare the system inoperable).

The BWROG has re-established the Detect & Suppress committee to lead development of an improved methodology for performing stability detect and suppress reload licensing calculations. The final recommended solution from this committee is expected in the fourth quarter of 2002. Until long-term resolution of this issue is finalized, CP&L will continue to operate BSEP Unit 1 with the OPRM trip function either operable, or enabled but declared inoperable, as described above.

Implementation of the new Unit 2 PRNM system with OPRM trip function in March 2003, is expected to incorporate the final long-term solution developed by the BWROG Detect & Suppress committee. However, if long-term resolution of this issue has not been finalized by the startup following installation of the Unit 2 modification, Unit 2 OPRM trip function operability will be assessed by performing the figure of merit calculation as described for Unit 1 above. OPRM trip function operability for both Units 1 and 2 will be assessed each cycle until long-term resolution of this issue is finalized.

NRC Question 5-23

Explain why it is desirable to change from EIA to Option III Long Term Stability Solution.

Response to Question 5-23

This change is desirable because it provides enhanced safety and supports improved plant operation at an affordable cost.

BSEP's EPU provides CP&L an opportunity not only to increase the plants' power output, but to improve the plants' material condition to support improved performance and an extended operating license. The Long-Term Stability Solution Option EIA was originally selected not on the basis of technical superiority, but on an evaluation of technical adequacy at a small fraction of the installation expense of Option III. The EPU upgrade to a new digital electronics PRNM system provides an opportunity to convert to Option III at a reasonable incremental cost. EIA's analytic Restricted Regions are not calculated on the basis of actual plant conditions, but must conservatively bound all operating conditions over the entire operating cycle. Consequently, operation in certain areas of the power/flow map is restricted more than is necessary for most conditions, which makes plant operation more challenging. Two frequently seen examples of how EIA restrictions can result in a plant trip from a normally recoverable condition are:

- EIA prohibits intentional entry into the Restricted Region unless the Fraction of Core Boiling Boundary (FCBB) is less than or equal to one. This precludes rapid deep power reductions that would be necessary on a loss of a feedwater pump, circulating water pump, fouled intake screens or fish run in the intake structure to avoid a plant trip.

- The restricted maneuvering room during recirculation pump restarts and startups results in a more complicated evolution than is otherwise required.

Such events have occurred at BSEP. If they result in a reactor scram, they not only represent a substantial operating cost, but also an avoidable safety risk.

Finally, Option III provides an intrinsically greater degree of protection for BSEP. Option EIA protection from THI is based on cycle-dependent calculated stability regions, with the attendant risk of calculational error, and relies on operator actions. Option III in contrast provides direct automatic scram of the plant based on redundant THI detection algorithms.

NRC Question 5-24

Justify that 120-day LCO 3.3.1.1 I.2 completion time is not needed.

Response to Question 5-24

Prior to the development of the Long-Term Stability Solutions, including Option III, prevention, detection, and suppression of THI was performed exclusively under operating procedures. These Operator stability-related functions are commonly referred to as interim corrective actions (ICAs) and are the same actions referenced in proposed TS 3.3.1.1 as alternate controls for the situation where the OPRM trip function is lost. These functions prevent operation in certain areas of the power/flow map to avoid THI, monitor stability through instrumentation whenever the plant is operating in a power/flow region associated with potential THI concerns, and prescribe specific actions in the event that THI is observed. The BWR plant fleet operated under ICAs as the standard controls successfully for over 10 years without incident. There is no basis for an arbitrary 120 day Limiting Condition for Operation (LCO) limit for restoring the OPRM system to operable provided the alternate ICA function is maintained in TSs, plant procedures, and Operator training. The risk of an instability event occurring at a particular plant while the OPRM trip function is inoperable is very small, and the ICA controls should be adequate to cope with the possibility. Even if the trip functions were inoperable, the monitoring capabilities of the system provide much earlier indication of THI than the original Local Power Range Monitor (LPRM)/Average Power Range Monitor (APRM) provided for use with the ICAs. The increased sensitivity of the new system improves the effectiveness of the ICA controls.

The 120 day LCO limit is an arbitrary length of time, which was chosen on recognition of the extended period which would be required to correct a design problem with the OPRM system. However, the first time such a design problem actually occurred (i.e., the generic DIVOM curve error described in the 10 CFR 21 notice) it was immediately recognized that it was not feasible to repair the problem in 120 days. Emergency licensing actions have been required to remove existing 120 day LCO restrictions. Emergency actions entail risk that is best avoided by prior planning to eliminate licensing actions for future design error notifications. The actual period of time required to repair a design flaw will be dependent on the nature of the flaw, and should be established at the time the error is discovered. The NRC is formally notified of significant design errors in accordance with 10 CFR 21 and has the authority to impose operating restrictions and/or schedule constrains as appropriate. For simple cases of equipment hardware failure, or loss of operability of the PRNM system apart from the OPRM trip function, the 8 hour

LCO requirement continues in force. The removal of a 120 day LCO does not affect the restrictions applicable to these situations.

Finally, prescribing a time limit (i.e., 120 day or otherwise) for the LCO suggests that this is the period of time acceptable for the system to be inoperable. In fact, the system is an enhancement relative to the ICAs, and while not essential, should always be maintained as operable when practical. The suggestion that some extended period of time like 120 days is a pre-approved duration for the system to be inoperable is not only arbitrary and impractical, but could encourage the licensee to allow the system to remain out of service longer than is appropriate. Removal of the 120 day limit instead emphasizes that each design flaw be addressed on a schedule appropriate to the nature of the error and the oversight of the NRC.

ATWS/Instability

NRC Question 5-25

The EPU submittal did not address whether operation at the EPU conditions might affect the potential for and impact of thermal-hydraulic instability. The ATWS/Instability for BWRs were generically dispositioned based on NRC review and acceptance of NEDO-32047-A, "ATWS Rule Issues Relative to BWR Core Thermal-hydraulic Stability," and NEDO-32164, "Mitigation of BWR Core Thermal-Hydraulic Instabilities in ATWS." In these topicals, the BWROG/GE analyzed the ATWS/ instability response of a BWR/5 and BWR/6, with and without ATWS mitigation actions. The following questions address the applicability of the generic ATWS/Instability evaluations for the Brunswick EPU conditions.

a. Table 5-1, "ATWS/Stability Transient Analysis Parameters," of NEDO-32047-A provides the initial conditions assumed in the ATWS instability evaluations. Confirm that the key parameters that affect thermal-hydraulic instability response (i.e core power density, axial power shapes, core radial power distribution, initial subcooling, and the instability response of the GE14/GE13 fuel) for the Brunswick EPU operation will not change the applicability of the generic ATWS/instability evaluation in NEDO-32047-A. If any of the key thermal-hydraulic instability parameters are not bounded, discuss the impact this may have on the evaluations of Brunswick Units 1 and 2 instability response (core-wide and regional).

b. NEDO-Section L.3.1, "Power Conditions for ATWS Evaluation," and L.3.2, "Operator Action," of the ELTR1 discusses some aspects of the ATWS instability and typical ATWS operator actions. For the EPU operation, confirm that the Brunswick Units 1 and 2 EOPs are consistent with the recommendations of ELTR1 and the NRC staff's positions in NEDO-32047-A safety evaluation report (SER). Explain why the ATWS/instability management strategics discussed in the NEDO-32164 would remain effective for Brunswick Units 1 and 2.

Response to Question 5-25a

- **Power Density/Core Flow:** The initial power/core flow ratio for the BSEP EPU operation is about 38.4 MW/Mlbm (i.e., 2923 MW and 76.2 Mlbm/hr). This is bounded by the values used in NEDO-32047A of 40.9 MW/Mlbm (i.e., 3323 MW and 10250 Kg/s or 81.3 Mlbm/hr).

- **Axial Power Shape:** A bottom-peak axial power shape is bounding for the ATWS stability evaluation in NEDO-32047A. The reported axial power shape is 1.34 at Node 4 (i.e., 1.34N4, out of 25 equal-length axial nodes, from bottom to top of active fuel length) during Middle-of-Cycle (MOC) exposure. The axial power shape for BSEP EPU at BOC is bottom peaked at 2.1N4 and the peak moves upward with extending exposure. At EOC, it becomes top-peaked (i.e., 1.29N9). Because the power shape varies with exposure, no single value is available to conclusively determine whether the NEDO-32047A or BSEP case is more bottom peaked. The axial power shape assumed in NEDO-32047A may not bound that in the BSEP EPU at MOC. However, there is sufficient margin in energy deposition (i.e., 78 cal/g versus 280 cal/g criterion) that slightly higher peak values in BSEP's axial power shape would yield an acceptable energy deposition value.

- **Radial Power Distribution:** Fuel bundle design limitations result in core designs with a flatter radial power distribution in order to implement power uprate. The power generation of the highest power bundle is essentially unchanged, because a similar design margin is maintained to LHGR design limits, which do not change for power uprate. The flatter power distribution means that more bundles will have power generation near to the highest power bundle in the core. Since higher power bundles have a greater pressure drop and corresponding lower channel flow, the flatter power profile means that there is also a flatter core flow profile. Therefore, the power uprate core designs increase the stability of the highest power (i.e., least stable) bundles by increasing their channel flow and therefore their single-phase to two-phase pressure drop. This flatter radial power distribution is beneficial for the ATWS instability mitigation strategies of lowering water level and injecting liquid boron since there is a more uniform flow distribution across the core. However, if there were no ATWS instability mitigation actions performed, the flatter power distribution means more fuel rods could experience extended dryout.

- **Initial Subcooling:** EPU impacts core inlet subcooling during the ATWS event via feedwater temperature; initially through the core inlet feedwater temperature, and later through the hotwell temperature, which controls the final feedwater temperature. The effect of EPU is that the feedwater temperature will increase slightly, from zero to at most 6°F, providing a negligible benefit with respect to THI. The BSEP EPU modification increases the full power initial feedwater temperature by 6°F, while the hotwell temperature change varies from 6°F higher in the summer to no change in the winter. Because the ATWS turbine trip analysis assumes loss of all feedwater heating, the feedwater temperature could theoretically eventually approach the hotwell temperature. Any changes in feedwater

temperature effects from EPU are negligible in comparison to the temperature difference between the 431°F initial feedwater and the 92°F hotwell. Furthermore, because of the inventory of water in the lower plenum, and the saturated water provided initially from recirculation pumps and during the ATWS from natural circulation, the core inlet temperature change from EPU is much less than the feedwater temperature change. Therefore the effect of initial subcooling from EPU is a negligible benefit with respect to THI.

For events with reduced initial feedwater temperature (i.e., final feedwater temperature reduction (FFWTR) and feedwater heater out-of-service (FWHOOS)), the EPU initial condition is no more limiting than the initial condition of the current full power operation. The allowable reduction in feedwater temperature for these modes of operation are not increased, and the initial subcooling is the same or less than the current initial condition, as explained above.

The initial full power feedwater temperature for the BSEP EPU operation is 431°F, or 11°F higher than the 420°F value used in NEDO-32047A. A higher initial value of feedwater temperature reduces the vulnerability to THI for BSEP, relative to the NEDO-32047A evaluation. Because the pre-EPU feedwater subcooling is presumably bounded by the NEDO-32047A assumptions, and the effect of EPU is to provide a negligible THI benefit due to changes in feedwater subcooling, the NEDO-32047A analysis remains bounding for BSEP after EPU.

- **GE13/GE14 Fuel:** The studies performed for NEDO-32047A and NEDO-32164 were performed for 8x8 GE fuel designs and limiting full power operating conditions. These conditions are limiting for many plant-specific power uprate conditions. However, they are not limiting for the BSEP EPU maximum extended load line limit analysis (MELLLA) initial condition. GE has recently performed sensitivity studies for GE14 fuel (i.e., 10x10 design) and for a more limiting full power operating condition than the BSEP EPU MELLLA initial condition. These studies show a fully coupled neutronic/THI power and flow response similar to the cases reported in NEDO-32047A and NEDO-32164. However, the GE14 fuel has a lower heat flux per rod than 8x8 fuel and is less susceptible to extended fuel rod dryout than the fuel previously reported in NEDO-32047A. The same conclusion is also applicable to the GE13 (i.e., 9x9 design) fuel. Therefore, the expected extent of fuel damage for an ATWS instability event without mitigation, from a condition more limiting than BSEP EPU MELLLA conditions, is bounded by the fuel damage calculation reported in NEDO-32047A.

<u>Response to Question 5-25b</u>

The Emergency Operating Procedures (EOPs) for BSEP Unit 1 and 2 have been developed consistent with BWR Emergency Procedure Guidelines (i.e., BWROG NEDO-31331). The BSEP EOPs include the following Operator actions as part of its ATWS control strategy:

a. Terminate feedwater flow,

b. Initiate the SLC system,

c. Start RHR in the pool cooling mode,

d. Maintain reactor pressure vessel (RPV) water level above Minimum Steam Cooling Water Level and two feet below the feedwater spargers.

The ELTR and the Safety Evaluation Report Associated with NEDO-32164 describe maintaining water level near top of active fuel and NEDO-32047A describes maintaining water level approximately 1 meter below the feedwater spargers. However, a subsequent NRC Safety Evaluation Report, dated June 6, 1996, for the proposed modifications to the BWR Emergency Procedure Guidelines Revision 4, concluded that it is acceptable to control water level between Minimum Steam Cooling Water Level and two feet below the feedwater spargers. This mitigation strategy has been incorporated into the BSEP Unit 1 and 2 EOPs.

The limiting postulated large power oscillations for ATWS instability events are initiated by the turbine trip event with scram failure, which results in high reactor power at natural circulation and high inlet subcooling. This sequence of events includes a core flow coastdown from a recirculation pump trip and the reduction of feedwater temperature due to the loss of feedwater heating. The Response to Question 5-25a indicates that the key parameters for BSEP Units 1 and 2 are acceptable as compared to the generic ATWS instability analysis in NEDO-32047-A. The instability event for BSEP EPU is consistent with the evaluated conditions, since the BSEP response to the key driving parameters is similar, and plant operating conditions are similarly constrained (i.e., by the MELLLA high rod line boundary). Therefore, the mitigation actions, i.e., reducing of water level and injecting of boron, are also evaluated for conditions which are acceptable as compared to the generic ATWS instability mitigation analysis in NEDO-32164. Since the BSEP EPU plant response and initial operating limitations are consistent with NEDO-32047-A and NEDO-32164, the ATWS instability management strategies evaluated in NEDO-32164 remain effective for the BSEP EPU.

Codes

NRC Question 5-26

Table 1-3 shows the ISCOR is used in many of the safety and accident analyses and the code is approved for some applications. The table indicates the code may be implicitly approved through the approval of NEDE-24011-A. However, the code seems to be used beyond core heat balance purposes. For each application, describe what the code is used for and if the code is approved by the NRC for the specific application.

Response to Question 5-26

Table 1-3 identifies that the computer code, ISCOR, is used for six different evaluation subjects for EPU. The following table describes what ISCOR is used for and if the use of the code is separately, explicitly approved by the NRC for the evaluation subject. In all cases the ISCOR

code is used as a steady state model for calculation of steady state core and bundle heat balances, bundle flows, initial condition thermal limits, loss coefficients, bypass heating and flow fractions, direct moderator heating, pressure drop for the core and bundles, and/or detailed pressure drop within the fuel bundle. All applications of the ISCOR code are consistent with the basis described in NEDE-24011-A, but, in addition, there are other approved applications or documentation of the code uses as noted below. Based on these applications, additional specific approval of the method has not been deemed necessary for essentially the same uses in the various analyses.

Evaluation Subject	Description of Use	Approval
ATWS	ISCOR is used to update the PANACEA bypass flow, channel flows and loss coefficients.	There is no explicit approval by the NRC for this application of ISCOR but it is consistent with the model description of NEDE-24011-A. Further documentation of the application of the methodology is given in NEDE-32868P.
ECCS-LOCA and Appendix R	The ISCOR code is used in the LOCA and Appendix R analysis to determine the initial steady-state input values for the: • Reactor heat balance • Core pressure drop • Inlet mass flow to hot channel • Ratio of hot channel to average channel mass flow • Detailed core pressure drop inputs for hot channel and average channel • Core exit steam and liquid conditions Appendix R analysis uses ISCOR for the initial reactor heat balance and the bundle input hydraulic and pressure drop conditions for the analysis.	There is no explicit approval by the NRC for this application of ISCOR but it is consistent with the model description of NEDE-24011-A and further reference is made to NEDE-30130-P-A, which was reviewed and approved for steady state analysis by the NRC.

Evaluation Subject	Description of Use	Approval
Reactor Core and Fuel Performance Reactor Heat Balance	ISCOR is used to calculate reactor heat balance conditions, the core pressure drop, local pressure drops in the hot and average channels, flow split between hot and average channels, mass flow in hot channel, bypass flow parameters and heat deposition, and thermal limits.	This is the specific application identified in NEDE-24011-A and NEDE-30130-P-A and has NRC approval for application.
Reactor Internal Pressure Difference	ISCOR is used to calculate reactor heat balance conditions, the core pressure drop, local pressure drops in the hot and average channels, flow split between hot and average channels, mass flow in hot channel, bypass flow parameters, etc. Over 50 core coolant hydraulic parameter values taken from ISCOR are input to the simulation of Emergency and Faulted Conditions using LAMB. These parameter values are placed by ISCOR into a CEDAR file.	There is no explicit approval by the NRC for this application of ISCOR but it is consistent with the model description of NEDE-24011-A and NEDE-3-130-P-A.
Transients	For transient analyses, the reactor heat balance from ISCOR is used as the basis for the initial conditions. The transient analyses use the ISCOR thermal hydraulic pressure drop models described in GESTAR II Section 4.2.3 through 4.2.5 to initialize and adjust the hot channel flow in TASC CPR calculations.	There is no explicit approval by the NRC for this application of ISCOR but it is consistent with the model description of NEDE-24011-A, NEDE-30130-P-A and NEDC-32082P. This application is consistent with the basis of Reactor Core and Fuel Performance and Reactor Heat Balance application.

NRC Question 5-27

The Brunswick power/flow map shows changes in the maximum core flow, indicated in Figure 2-1 of the PUSAR as segments FG, GH, HI, and IJ. What increased core flow are BSEP Units 1 and 2 licensed for and explain the physical reasons for the reduction in the maximum core flow as shown in Figure 2-1.

Also, explain segment KJ of the power flow map, designated as "jet pump and Recirculation pump cavitation protection." This differs from the usual power/flow map cavitation interlock,

which is based on the feedwater flow. Are there specific reasons for changes in the jet pump losses for BSEP Units 1 and 2.

Table 1-2 of the PUSAR indicates almost identical operating conditions for BSEP Units 1 and 2. Are there any differences in the power/ flow map for Units 1 and 2?

Response to Question 5-27

BSEP Units 1 and 2 are currently licensed for the region indicated by the line segments GH, HI, IJ, and JK shown on Figure 2-1, which are shown in UFSAR Figure 4.4.1-1 as segments B'B, BE, EG and GF. As indicated in the following table, the only difference between the licensed values for these segments and EPU is for Point B (i.e., point G on Figure 2-1) that is 104.3% flow for Unit 1 and 104.5% for Unit 2. For EPU, the maximum core flow for this point was changed for Unit 1 to 104.5% flow so that the power flow maps for the two units would be the same. For EPU conditions, the maximum core flow of 104.5% was not changed as indicated by the line segment FG on Figure 2-1. The line segment JK of the flow map provides additional margin to prevent operation near cavitating conditions. Although not shown, the feedwater flow cavitation interlock is still active in this region to provide automatic protection.

The EPU power/flow maps for Units 1 and 2 are identical.

Comparison of Current Licensed Power / Flow Values to EPU Values			
Power/Flow Point		**Currently Licensed Values**	**EPU Values**
UFSAR	***Figure 2-1****	***(MWTh / % Flow)***	***(MWTh / % Flow)***
B'	G	Unit 1 : 2558/104.3	2558/104.5
		Unit 2 : 2558/104.5	2558/104.5
B	H	Unit 1 : 2436/105.0	2436/105.0
		Unit 2 : 2436/105.0	2436/105.0
E	I	Unit 1 : 1706/110.0	1706/110.0
		Unit 2 : 1706/110.0	1706/110.0
G	J	Unit 1 : 926/110.0	926/110.0
		Unit 2 : 926/110.0	926/110.0
F	K	Unit 1 : 585/99.0	585/99.0
		Unit 2 : 585/99.0	585/99.0

* Updated Final Safety Analysis Report Power/Flow Operating Map for Power Uprate Figure 4.4.1-1, Revision 15.

The power/flow map is a licensing region which defines boundaries, inside of which operation of the plant has been analyzed and demonstrated to meet all applicable fuel and system design criteria. The power/flow map does not necessarily reflect actual plant capabilities. However, the plant will not be intentionally operated outside of the boundaries of the power/flow map.

Expansion of the power/flow map would allow more flexibility in plant operation, but generally at the cost of imposing tighter fuel operating limits over the allowed regions. At current 2558 MWt conditions, Unit 1 could, under Increased Core Flow (ICF) conditions, operate above 104.5%. Since Unit 2 has greater pressure losses through its smaller size inlet orifices on the fuel support pieces, the Unit 2 recirculation pumps can generate a maximum of 104.1% flow at 2558 MWt. EPU licensing calculations support ICF up to 104.5% at 2923 MWt for both Units. EPU design calculations, assuming clean, as-built conditions, indicate that, after the full EPU, the recirculation pumps will deliver about 1.8% less flow. This corresponds to an expected maximum ICF for Unit 2 of 102.3%. Unit 1 should achieve 104.5%. This inability of Unit 2 to operate at the full licensed ICF flow has no adverse safety consequences. It merely has the economic consequence of reducing the effectiveness of fuel utilization slightly. Should CP&L decide it is economically advantageous, BSEP may perform improvements to the plant recirculation system (e.g., solid state variable speed drives or core orifice resizing) to permit increased Unit 2 ICF to the limit allowed by the power/flow map. However, no such improvements are currently being pursued by CP&L.