CP&L
A Progress Energy Company

John S. Keenan
Vice President
Brunswick Nuclear Plant

DEC 2 0 2001

SERIAL: BSEP 01-0165
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 13, 2001, the NRC provided an electronic version of a Request For Additional Information (RAI) associated with CP&L's proposed exception to one of the large transient tests, which requires an automatic scram from high power (i.e., main steam isolation valve closure), specified in Section 5.11.9 and Appendix L, Section L.2 of General Electric (GE) Company's Licensing Topical Report for Extended Power Uprate NEDC-32424P-A (ELTR-1), February 1999. The response to this RAI is enclosed.

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

Sincerely,

John S. Keenan for

P.O. Box 10429
Southport, NC 28461

T > 910.457.2496
F > 910.457.2803

A001

MAT/mat

Enclosure:
Response to Request For Additional Information (RAI) 12

Jeffrey J. Lyash, 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.

Dean L. Mason
Notary (Seal)

My commission expires: 8/29/04

cc:

U. S. Nuclear Regulatory Commission, Region II
ATTN: Dr. Bruce S. Mallett, Regional Administrator
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, GA 30303-8931

U. S. Nuclear Regulatory Commission
ATTN: Mr. Theodore A. Easlick, NRC Senior Resident Inspector
8470 River Road
Southport, NC 28461-8869

U. S. Nuclear Regulatory Commission
ATTN: Mr. Allen G. Hansen (Mail Stop OWFN 8G9)
11555 Rockville Pike
Rockville, MD 20852-2738

U. S. Nuclear Regulatory Commission
ATTN: Mr. Mohammed Shuaibi (Mail Stop OWFN 8H4A)
11555 Rockville Pike
Rockville, MD 20852-2738

Ms. Jo A. Sanford
Chair - North Carolina Utilities Commission
P.O. Box 29510
Raleigh, NC 27626-0510

Mr. Mel Fry
Director - Division of Radiation Protection
North Carolina Department of Environment and Natural Resources
3825 Barrett Drive
Raleigh, NC 27609-7221

ENCLOSURE

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)

Response to Request For Additional Information (RAI) 12

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 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 13, 2001, the NRC provided an electronic version of a Request For Additional Information (RAI) associated with CP&L's proposed exception to one of the large transient tests, which requires an automatic scram from high power (i.e., main steam isolation valve (MSIV) closure), specified in Section 5.11.9 and Appendix L, Section L.2 of General Electric (GE) Company's Licensing Topical Report for Extended Power Uprate NEDC-32424P-A (ELTR-1), February 1999. The responses to this RAI follow.

NRC Question 12-1

Provide justification for not performing the large transient tests. As part of this justification address the following:

a. Identify the plant systems and components challenged by the large transient tests under consideration (i.e., Load Rejection and Main Steam Isolation Valve Closure tests) and those systems'/component's parameters important for the tests (e.g., valve closure time).

b. Identify modifications made to these systems and components as a result of uprate.

c. Provide an evaluation of the effect of the power uprate for both steady state and transient response (e.g., increased power, steam flow, feed flow, etc.) on these systems and components.

d. Describe the testing and data collection that is being performed on these systems and components including any that is part of the power ascension test plan.

e. Discuss and evaluate related past experience regarding these types of transients at other uprated plants.

Response to Question 12-1

As discussed in Enclosure 6 of CP&L's extended power uprate (EPU) amendment request (Serial: BSEP 01-0086, dated August 9, 2001), the Generator Load Rejection test does not need to be performed for BSEP. Section L.2.4 (2) of ELTR-1 (NEDC-32424-P-A) specifies, "When the power uprate is within 10% and 15% power of previously recorded data, for MSIV closure and Generator Load Rejection events, respectively, no uprate specific tests are necessary. Previously recorded data may include unplanned as well as planned transients." Additionally, the response to a RAI, included in the NRC approved copy of ELTR-1, also indicates the acceptability of data available as a result of inadvertent events in lieu of data obtained from a special test in fulfilling the large transient testing requirements. BSEP Unit 2 experienced an unplanned Generator Load Rejection from approximately 2558 MWt that provides the data necessary to fulfill the requirements of Section L.2.4 of ELTR-1 up to and including power levels of 2923 MWt for the Generator Load Rejection test. The BSEP Generator Load Rejection event occurred on September 22, 2000, and was reported to the NRC in Licensee Event Report (LER) 2-00-002, dated October 20, 2000. No anomalies were seen in the plant's response to this event. This event satisfies the ELTR-1 requirement for previously recorded Generator Load Rejection transient data within 15% of the BSEP EPU licensed power level of 2923 MWt.

Given the above, a detailed basis for not performing the Generator Load Rejection test is not applicable. This response will focus on the MSIV Closure test.

Response to Question 12-1a

MSIV closure is an Anticipated Operational Occurrence (i.e., AOO or transient) as described in Chapter 15 of the BSEP Updated Final Safety Analysis Report (UFSAR). Without a concurrent failure of the MSIV position switches this transient is not considered significant enough to warrant routine re-evaluation. The MSIV closure transient, assuming the backup flux scram versus the valve position scram, is more significant. The UFSAR has been regularly updated for this case and it has been re-evaluated for EPU. The UFSAR indicates that the most significant aspect of this case is overpressure protection.

ELTR-1 indicates that large transient tests would be done similar to the original startup tests. The original MSIV closure test allowed the scram to be initiated by the MSIV position switches. As such, if the original MSIV closure test were re-performed, the results would be much less significant than the MSIV closure analysis performed by GE for EPU. The critical sequence of events and component challenges for a MSIV closure test would be as described below. Note that all values for vessel level are based on inches above normal instrument zero located 367 inches above vessel zero.

- When the MSIVs close to the 90% open position, valve limit switches would generate a scram signal.
- The scram signal would initiate control blade insertion. This is expected prior to MSIV closure causing significant reduction in main steamline (MSL) flow.
- As MSIVs closure starts to restrict steam flow there will be an increase of vessel pressure. However, there will be little or no flux increase as the negative reactivity of control blade insertion is larger than the reactivity increase due to pressure change.
- The MSIVs close in 3 to 5 seconds.
- After MSIV closure, vessel pressure will increase until an adequate number of Safety Relief Valves (SRVs) open. The pressure increase is expected to be from 1030 psig to at least 1130 psig (i.e., the low setpoint group nominal value), but not more than 1184 (i.e., the high setpoint group Technical Specification allowable value).
- All SRVs re-close when vessel pressure drops to approximately 1060 psig.
- Vessel pressure would then cycle between approximately 1060 psig and 1130 psig until operators take manual actions to control pressure.
- With closure of the MSIVs causing a reduction in steam flow, the feedwater control system will respond to avoid excessive vessel level increase. If level increases from the normal value of 187 inches to 206 inches, with 209.5 inches being the analytical limit, all operating turbines are expected to trip.
- After the MSIVs close, the steam supply for the feedwater pump turbines will be lost. Once feedwater is lost, vessel level will drop until High Pressure Coolant Injection (HPCI) and/or Reactor Core Isolation Cooling (RCIC) automatically start at 105 inches, with 92 inches being the analytical limit.
- Unless operators take action to control HPCI and/or RCIC injection flow rate, vessel level will increase to a level of 206 inches at which point the HPCI and RCIC turbines will trip.
- Unless operators take actions to control level, the vessel level will cycle from 105 inches indicated to 206 inches as HPCI and/or RCIC automatic operation continues.

Since the test would be modeled after the original MSIV closure test, the important parameters (i.e., acceptance criteria) to be verified would be:

1. Increase in heat flux shall be minimal (i.e., 0% desired, up to 2% with evaluation). No thermal limits are to be exceeded.

2. Reactor pressure rise shall be close to prediction (i.e., 120 psi desired, higher with evaluation).

3. MSIV closure time must be between 3 and 5 seconds.

4. The SRVs must close properly without leakage.

5. Feedwater controls must automatically prevent flooding of the main steam lines.

6. The Reactor Core Isolation Cooling (RCIC) system should start automatically and operate without isolating.

Response to Question 12-1b

For the affected systems and components, the only critical modifications for EPU are associated with the feedwater system (i.e., turbines and pumps) and the feedwater control system (i.e., Digital Feedwater Control System software). As discussed below, feedwater system response after these modifications will be adequately demonstrated without the MSIV closure test. Enclosure 2 of CP&L's EPU amendment request (Serial: BSEP 01-0086, dated August 9, 2001) provides the list of planned modifications supporting the EPU.

Response to Question 12-1c

- The MSIV limit switches that provide the scram signal are highly reliable devices that are suitable for all aspects of this application including environmental requirements. There is no direct effect by any EPU changes on these switches. There may be an indirect impact caused by slightly higher ambient temperatures, but the increased temperatures will still be well below the qualification temperature. These switches are expected to be equally reliable before and after EPU.

- The Reactor Protection System (RPS) and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any EPU changes. Minor changes in pressure drops across vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. Technical Specification (TS) requirements for these components will continue to be met.

- MSIV closure time is an important parameter. Because steam flow assists MSIV closure, acceptance criteria 3 (i.e., in Response to Question 12-1a) was established to verify that the steam flow from the reactor was not shut off faster than the assumed 3 seconds. Faster than desired closure could affect acceptance criteria 1, which monitored fuel thermal performance.

  For this event, the closure of the MSIVs causes a vessel pressure increase and an increase in reactivity. Once the MSIV disc has traveled far enough to begin restricting steam flow, the increased steam flow and core thermal power due to EPU would tend to increase the rate at which pressure increases. However, the negative reactivity of the scram from MSIV position switches is expected to start before the start of the positive reactivity from

the pressure increase. As a result, a minimal increase in heat flux for both the current and post-EPU configuration is expected.

Actual MSIV closure speed is controlled by adjustments to the actuator and is considered very reliable. MSIV closure speed verification is also a key parameter that is checked during actual events. Industry experience, including BSEP, has shown that there are no significant generic problems with this design. Confidence is very high that steam line closure would not be less than assumed by the analysis.

- Due to the minimal nature of the flux transient, the total expected reactor pressure rise (i.e., acceptance criteria 2), is largely dependent on SRV setpoint performance. There has been an industry issue with SRV setpoint performance. However, BSEP has implemented design changes and maintenance improvements that have greatly reduced concerns about SRV setpoint upward drift. Since these improvements were implemented, no surveillance results have had more than two SRVs out of specification high and the last two sets of tests results had no SRVs out of specification high. Note that this is bounded by the BSEP design analysis for peak vessel pressure which assumes two of the eleven SRVs do not open at all. Given the improved performance of the BSEP SRVs along with the design margins, performance of an actual MSIV closure test would provide little benefit, for demonstrating vessel overpressure protection, that is not already accomplished by the component level testing that is routinely performed in accordance with the BSEP TSs.

  Since rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after an SRV lift. Because SRV leakage performance is considered acceptable at the current conditions, which match EPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance will continue to be acceptable at EPU conditions. An MSIV closure test would provide no significant additional confirmation of the acceptance criteria 4 than the routine component testing performed every cycle, in accordance with the BSEP TSs.

- The feedwater response acceptance criteria was to avoid overfilling of the vessel at above 260 inches. Since the feedwater turbines, the HPCI turbine, and the RCIC turbine all receive trip signals prior to level reaching 208 inches, a substantial margin exists. BSEP operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. EPU will result in only a minor change in expected overshoot. As long as the above turbine trips work as designed, there is adequate confidence that the vessel level will remain well below the main steam lines under EPU conditions. These trip functions are routinely verified as required by TSs and are considered very reliable.

- RCIC has been successfully used for vessel level control a number of times at BSEP. The most recent examples were a brief injection during a September 20, 1995 Unit 1 scram, numerous injections during a July 13, 1995 Unit 1 scram and an injection during the July 27, 1996 planned Unit 2 maintenance shutdown. Reactor steam dome pressure and SRV setpoints were increased as part of the 105% uprate. Since that time, RCIC has been routinely tested to assure that it can deliver rated flow and pressure. The above examples are adequate to show that RCIC can reliably deliver rated flow. The original testing did not take any action to prevent HPCI operation. Since HPCI starts at the same vessel level as RCIC, the test would result in operation of both systems unless operators were to intervene. Therefore, verification that RCIC alone would maintain level was not part of the test scope.

Response to Question 12-1d

TSs require testing for most of the critical performance items discussed above. A summary of testing is as follows:

- MSIV limit switches are verified to generate scram signals quarterly.
- Rod insertion times are verified for at least 10% of the core quarterly, with 100% of the population being tested during each refueling outage, prior to exceeding 40% power following the completion of the outage.
- MSIV closure time is verified at least once per operating cycle.
- SRV setpoints are verified once per cycle as per ASME requirements enforced by TSs.
- SRV leakage is not monitored for compliance with any TS. It is being monitored in accordance with a trending program for Maintenance Rule and commercial considerations.
- High vessel level trip instruments are functionally tested quarterly.
- RCIC system start capability and system capacity are verified quarterly.
- Digital Feedwater Control System/Reactor Feedpump Response Testing will be performed during the power ascension test program.
- Reactor Feedpump Runout data collection and evaluation will be performed during the power ascension test program.

Response to Question 12-1e

Industry Boiling Water Reactor (BWR) Power Uprate Experience

Southern Nuclear Operating Company's (SNOC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. BSEP Units 1 and 2 are similar in design, size and vintage as Hatch. Hatch is a BWR/4 with a Mark I containment of essentially the same design as BSEP, including the key balance of plant area of turbine-generator control logic (i.e., Electro-Hydraulic Control system). Consequently, the BSEP plant response to transients would be very similar to Hatch. Although Hatch was not required to perform large transient testing, Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98% of uprated power in the summer of 1999. As noted in SNOC's LER 1999-005, no anomalies were seen in the plant's response to this event. In addition, Hatch Unit 1 has experienced one turbine trip and one generator load reject event subsequent to its uprate (i.e., LERs 2000-004 and 2001-002). Again, the behavior of the primary safety systems was as expected. No new plant behaviors were observed that would indicate that the analytical models being used are not capable of modeling plant behavior at EPU conditions.

The Leibstadt (i.e., KKL) power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 3138 MWt (i.e., 104.2% of Original Licensed Thermal Power (OLTP)) to 3515 MWt (i.e., 116.7% OLTP). Uprate testing was performed at 3327 MWt (i.e., 110.5% OLTP) in 1998, 3420 MWt (i.e., 113.5% OLTP) in 1999 and 3515 MWt in 2000.

KKL testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The KKL turbine and generator trip testing demonstrated the performance of equipment that was modified in preparation for the higher power levels. Equipment that was not modified performed as before. The reactor vessel pressure was controlled at the same operating point for all of the uprated power conditions. No unexpected performance was observed except in the fine-tuning of the turbine bypass opening that was done as the series of tests progressed. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close matches observed with predicted response provide additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

From the power uprate experience discussed above, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. Since the BSEP uprate does not involve reactor pressure changes, this experience is applicable. Based on industry experience, GE has submitted a licensing topical report for NRC review that applies to EPUs accomplished without reactor pressure increases. This topical report does not include large transient testing as a requirement.

The safety analyses performed for BSEP used the NRC-approved ODYN transient modeling code. The NRC accepts this code for GE BWRs with a range of power levels and power

densities that bound the requested power uprate for BSEP. The ODYN code has been benchmarked against BWR test data and has incorporated industry experience gained from previous transient modeling codes. ODYN uses plant specific inputs and models all the essential physical phenomena for predicting integrated plant response to the analyzed transients. Thus, the ODYN code will accurately and/or conservatively predict the integrated plant response to these transients at EPU power levels and no new information about transient modeling is expected to be gained from performing these large transient tests. This is especially true for the MSIV closure test where the lack of MSIV position switch failures, as modeled in the transient analysis, would affect all aspects of the response and prevent realistic comparisons.

NRC Question 12-2

Identify any new systems or features being installed and justify the proposal to not perform an integrated plant test for purposes of demonstrating plant response with the new system/feature.

Response to Question 12-2

No new systems or features are being installed that would be expected to have a significant impact on the response to any large transient test. Planned modifications to the condensate and feedwater systems may include items that individually could be considered new features. However, these items will not adversely affect the overall performance of the feedwater system and the essential feature (i.e., high level trip) is unaffected.