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April 3, 2003
NL-03-058

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

SUBJECT: Indian Point Nuclear Generating Unit No.2
Docket No. 50-247
Reply to Request for Additional Information
Regarding Proposed License Amendment for
1.4% Measurement Uncertainty Recapture Power Uprate

REFERENCES:

1. NRC letter to Entergy Nuclear Operations, Inc; "Request for Additional Information, TAC NO. MB6950," dated March 11, 2003.
2. Entergy letter to NRC, NL-02-155, "Proposed Changes to Technical Specifications: Measurement Uncertainty Recapture Power Uprate, Increase of Licensed Thermal Power (1.4%)", dated December 12, 2002.

Dear Sir:

This letter provides the additional information requested by the NRC in Reference 1 regarding the license amendment request submitted by Entergy Nuclear Operations, Inc (ENO) in Reference 2. The additional information is provided in Attachment I.

NRC questions 14 and 16 requested information pertaining to the testing of the Leading Edge Flow Meter (LEFM) flow elements and the development of calibration factors for those elements. Accordingly, ENO is enclosing the following documents:

1) Caldon, Inc. report ER-290, "Bounding Uncertainty Analysis for Thermal Power Determination at Indian Point Unit 2 Nuclear Power Station using the LEFM-Check System".

2) MPR Associates, Inc. report MPR-1614, "Feedwater Flow Measurement with LEFM Chordal Systems at Indian Point Unit 2 – Configuration and Uncertainty Analysis", October 1995.

3) Responses to Questions 13, 14, and 16 of the NRC Request for Additional Information.

4) Alden Research Laboratory report ARL 106-79 / C91, "Calibration – Indian Point ; Two 18" Ultrasonic Flowmeters", May, June 1979.

Items 1, 2, and 3 contain information that is proprietary to Caldon, Inc. Two copies each, of the proprietary and non-proprietary versions of these documents are enclosed. Also enclosed is Caldon, Inc authorization letter dated April 1, 2003 (CAW 03-02), with the accompanying affidavit. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses the considerations listed in paragraph (b)(4) of Section 2.790 of the Commission's regulations. ENO requests that the information that is proprietary to Caldon be withheld from public disclosure in accordance with 10 CFR 2.790.

Correspondence with respect to the application for withholding of proprietary informationshould reference CAW-02-04 and should be addressed to Calvin R. Hastings - President and CEO, Caldon, Inc., 1070 Banksville Avenue, Pittsburgh, Pennsylvania 15216.

The responses to the NRC questions do not change the conclusions of the no significant hazards evaluation or the proposed changes to the Technical Specifications previously provided in Reference 2. There are no new commitments identified in this letter. If you have any questions or require additional information, please contact Mr. Kevin Kingsley at 914-734-5581.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 4-3-03

Very truly yours,

Fred R. Dacimo
Vice President, Operations
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cc:

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ATTACHMENT I TO NL-03-058

RESPONSE TO NRC QUESTIONS REGARDING

PROPOSED LICENSE AMENDMENT REQUEST FOR

1.4% MEASUREMENT UNCERTAINTY RECAPTURE POWER UPRATE

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

<u>Question 1</u>:

Please provide a listing of the Indian Point Unit 2 (IP2) instrumentation uncertainty components used as inputs to the reactor power uncertainty calculation, including their associated measurement uncertainties and uncertainty values with respect to power. Discuss the methodology used and show that the mathematical combination of these uncertainties is less than the stated 0.6 percent (with Caldon Leading Edge Flow Meter (LEFM) Check Flow Elements installed) for IP2.

<u>Response 1:</u>

A detailed listing of the IP2 instrument uncertainty components used as inputs to the reactor power uncertainty calculation is contained in WCAP-15904, Rev.0, provided as an enclosure to the original license amendment request (ENO Letter NL-020155). The methodology and the mathematical combination of uncertainties are also contained in WCAP-15904, Rev. 0.

<u>Question 2</u>:

The Nuclear Steam Supply System Operating Point parameters for power uprate conditions were calculated for a core power uprate of 1.4 percent (3,114.4 MWt). Provide a listing of the Final Safety Analysis Report Chapter 14 transients and accidents analyses which incorporate these uprate operating point parameters. For those that do not, provide justification that the current values used in the analyses are bounding.

<u>Response 2:</u>

Section 8 of Attachment III of the license amendment request included Table 8-1 and associated text that delineate and explain how the various IP2 UFSAR Chapter 14 safety analyses events were classified. The basic classifications are "Affected" or "Unaffected" events according to the NRC guidance in RIS 2002-03. Based on RIS 2003-03, Unaffected events are existing analyses of record that bound plant operation at the 1.4% power level conditions. Therefore, new analyses were not necessary for Unaffected events (listed in Table 8-1)Additionally, the NSSS operating parameter data were not explicitly incorporated into the existing licensing basis analyses for Unaffected events.

There were six Affected non-LOCA events (explicitly listed in Table 8-1). The three Affected events required reanalysis to address the potential effects of the 1.4% power uprate are uncontrolled RCCA bank withdrawal at power, loss of external electrical load-DNB analysis, and excessive heat removal due to feedwater system malfunctions. These three events explicitly incorporate the 1.4% power uprate operating conditions and are discussed in detail in Section 8.3.3 (Affected Non-LOCA Events Re-analyzed) of Attachment III of the license amendment request.

The potential effects of the 1.4% power uprate on the other three Affected events (rod cluster control assembly drop, loss of reactor coolant flow-partial and complete loss of forced reactor coolant flow, and locked rotor accident – DNB analysis) were evaluated as described in Section 8.3.4 (Affected Non-LOCA Events Evaluated) of Attachment IIIof the license amendment request. These evaluations did not explicitly incorporate the 1.4% power uprate operating conditions into the existing safety analyses. However, as described in Section 8.3.4, the changes in the operating conditions were evaluated and the results show that the current analyses continue to be bounding for the 1.4% power uprate.

Question 3:

Please provide a quantitative discussion confirming that the Low Temperature Overpressure Protection Relief valves have adequate relief capacity to remove the additional decay heat generated by the 1.4 percent power uprate such that there is no increase in peak pressure for this transient. Include a discussion of the NRC-approved methodology used to perform this analysis.

Response 3:

Overpressure Protection System (OPS) events could potentially occur during cold shutdown operation (RCS temperature less than about 350°F). The 1.4% power uprating is not changing any plant condition for which OPS is affected. For these events, the plant is in a shut down condition, so the uprating does not affect the plant response for these events.

The OPS at IP2 is designed to respond to mass and heat injection events when the RCS is below the arming temperature (currently 320 °F). This is well below the zero power Tavg of 547 °F. The mass injection event would be the result of inadvertent charging or safety injection, neither of which is related to decay heat rate. The heat injection event presumes the addition of latent secondary heat from the Steam Generator to the RCS subsequent to pump start; it is bounded by an allowable primary-to-secondary temperature difference (TS 3.1.A.4) and is not related to decay heat.

The intent of OPS is to prevent violation of the reactor vessel Appendix G pressuretemperature limits. The Appendix G limit is not changing due to the 1.4% power uprating. Therefore, there is no effect on OPS due to the 1.4% power uprating.

Also, the calculation upon which the OPS setpoint is based (IP2-FIX-00056-01) explains in quantitative detail the derivation of the setpoint and all other low-temperature RCS limits. This calculation was previously submitted to the NRC to support IP2 Technical Specification Amendment No. 224.

Therefore, there is no aspect of the IP2 OPS or setpoints that is challenged in any way by a 1.4% increase in decay heat load.

Question 4:

With respect to the impacts of the proposed power uprate on the nuclear, thermal-hydraulic and fuel rod design analyses, please provide a listing of the NRC-approved codes and methodologies used for the design analyses discussed in Section 7.10 of the Attachment III of the submittal and confirm that all parameters and assumptions to be used for analyses described in Sections 7.10 of the Attachment III remain within any code limitations or restrictions.

Response 4:

The codes and methods used for the 1.4% power uprate design analyses discussed in Section 7.10 of the Attachment III of the license amendment request are the same as those used for the following Westinghouse reload methodologies, previously approved by the NRC.

Reload Methodology:

- Davidson, S. L., et al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9272- P-A (proprietary) and WCAP-9272-NP-A (non-proprietary), July 1985.

Nuclear Design:

- Nguyen, T. Q., et al., "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A, June 1988.
- Liu, Y. S., et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A, September 1986.

Fuel Rod Design:

- Slagle, W. H. (Editor), et al., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1 (Proprietary) and WCAP-15064-NP-A, Revision 1 (Non-Proprietary), July 2000.

Thermal and Hydraulic Design:

- Sung, Y. et al, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A/WCAP-15306-NP-A, October 1999.

Confirmation of parameters and assumptions used for the fuel-related analyses described in Section 7.10 is performed in two phases:

Phase I consisted of the analyses performed for the non-LOCA statepoints that changed as a result of the 1.4% power uprate conditions. For the statepoints that did change, an analysis was performed to show that the new statepoints meet the current design basis for a mid-cycle uprate of IP2 Cycle 16. Standard Westinghouse core reload methodologies described in Reference 1 (above) are used for these analyses.

Phase II addresses the non-LOCA statepoints that do not change, but still need to be addressed for the change in core power conditions. As with the Phase I calculations, these statepoints are analyzed and addressed using standard Westinghouse core reload methods and codes. In order to minimize uncertainties with respect to fuel exposure, these analyses are typically performed approximately two months prior to the actual implementation date of the 1.4% power uprate. The results and conclusions are summarized in a revised version of the cycle specific Reload Safety Evaluation (RSE) document. Revision 1 of the IP2 Cycle 16 RSE presentsthe results and conclusions for the 1.4% uprate analysis and will be finalized prior to implementation of the 1.4% power uprate. These calculations will be subsequently repeated for all future cycles.

This process also confirms that all parameters and assumptions used for analyses described in Section 7.10 of Attachment III of the license amendment request remain within code limitations and restrictions.

Question 5:

Provide a more detailed anticipated transient without scram (ATWS) evaluation that is applicable to IP2 at power uprate conditions to demonstrate that the peak primary system pressure will not exceed the ASME Stress Level C limits of 3200 psig. Justify that the assumptions for the analyses are adequate as they relate to input parameters such as the initial power level, current fuel enrichment, moderator temperature coefficient (MTC), pressurizer safety and relief valves capacity, reactor coolant system volume, steam generator pressure, auxiliary feedwater (AFW) flow rate and its actuation delay time, and the setpoint for the ATWS Mitigation System Actuation Circuitry (AMSAC) system to actuate the AFW and trip the turbine. The submittal should include a discussion and applicable values of the unfavorable exposure time for the MTC assumed in the analyses. Explain why the Technical Specification value of MTC less than zero would assure the assumed MTC value in the ATWS analysis.

Response 5:

A detailed evaluation concerning anticipated transients without scram (ATWS) is presented in Section 8.3.6.8 of Attachment III of the license amendment request. The level of detail included in Section 8.3.6.8 by Westinghouse is consistent with the level of detail provided in a response to a similar RAI that was generated by the NRC regarding theIndian Point Unit 3 1.4% power uprate project. Section 8.3.6.8 also includes a thorough discussion concerning the ATWS analysis assumptions for power level, moderator temperature coefficient (MTC), pressurizer relief and safety valve capacities, and the auxiliary feedwater (AFW) flow rate (including unfavorable exposure time). From the discussion in Section 8.3.6.8, a 1.4% increase in power would not challenge the ASME stress level C limits of 3200 psia.

The following discussion explains why the TS value of MTC less than zero would assure the assumed MTC value in the ATWS analysis. In defining the 95%/99% MTC values for plants limited to a negative MTC at full power conditions (e.g., IP2, with the < 0 pcm/°F at all powers), the ATWS generic analyses (documented in NS-TMA-2182) assumed conservative assumptions when determining the fraction of the time the coefficient would be more positive than specified. These assumptions include the expectation that continuous load follow will exist throughout core life, slow plant start-up rates, monthly short and long shutdown periods, the effect power change has on fuel average temperature (during start-up), and the impact equilibrium xenon has on boron concentration, all of which will generate a least negative coefficient. With these assumptions, the calculations supporting the ATWS generic analyses show that the coefficient will be more negative than -8 pcm/ °F for 95% of the time, and more negative than -7 pcm / °F for 99% of the time that the core power is greater then 80% of nominal.

Question 6:

Westinghouse recently issued three Nuclear Service Advisory Letters (NSALs), NSAL 02-3 and revision 1, NSAL 02-4 and NSAL 02-5, to document the problems with the Westinghouse designed steam generator (SG) water level setpoint uncertainties. NSAL 02-3 and its revision, issued on February 15, 2002, and April 8, 2002, respectively, deal with the uncertainties caused by the mid-deck plate located between the upper and lower taps used for SG measurements and affect the low-low level trip setpoint (used in the analyses for events such as the feedwater line break, ATWS and steam line break). NSAL 02-4, issued on February 19, 2002, deals with the uncertainties created because the void content of the two-phase mixture above the mid-deck plate was not reflected in the calculation and affect the high-high level trip setpoint. NSAL 02-5, issued on February 19, 2002, deals with the initial conditions assumed in the SG water level related safety analyses. The analyses may not be bounding because of velocity head effects or mid-deck plate differential pressures which have resulted in significant increases in the control system uncertainties. Discuss how IP2 accounted for these uncertainties documented in these advisory letters in determining the SG water level setpoints. Also, discuss the effects of the water level uncertainties on the analyses of record for the loss-of-coolant accident (LOCA) and non-LOCA transients and the ATWS event, and verify that with consideration of all the water level uncertainties, the current analyses are still limiting.

Response 6:

IP2 is operating with Westinghouse Model 44F steam generators. In comparison to other Westinghouse steam generator models, the Model 44F steam generator has a relatively large flow area through the mid-deck plate region of the steam generator and, as such, there is essentially no pressure drop across the mid-deck plate region of the Model 44F steam generators. This is shown for IP2 in the attachment to NSAL 02-3, Rev.1. Therefore, with respect to NSAL 02-3 and NSAL 02-5, IP2 is not affected and the current safety analyses remain limiting. With respect to NSAL-02-4, the IP2 safety analysis limits bound the values addressed in the NSAL. Therefore, the concerns identified in the NSAL have been addressed for IP2.

There is no effect of the water level uncertainties on the analyses of record for the loss-of-coolant accident (LOCA) and non-LOCA transients and the ATWS event, and the current analyses remain limiting.

<u>Question 7</u>:

Upon reviewing LBLOCA models for power uprates, the NRC has recently found plants that require changes to their operating procedures because of inadequate hot leg switch-over times and boron precipitation modeling. Demonstrate that your LBLOCA model continues to comply with 10 CFR 50.46 during the switch-over from the refueling water storage tank to the Containment Sump. Also, discuss how your analyses account for boric acid buildup during long-term core cooling; and discuss how your predicted time to initiate hot leg injection corresponds to the times in your operating procedures.

<u>Response 7:</u>

The methodology used to confirm post-LOCA long-term core cooling capabilities for IP2 establishes a post-LOCA Hot Leg Switchover (HLSO) time to support realignment of the recirculation safety injection (SI) flow from the cold legs to the hot legs. This realignment is required to preclude boron precipitation in the reactor vessel following a large-break LOCA. For a cold-leg break where injected SI water would boil off due to decay heat, the potential would exist for the boric acid solution in the reactor vessel to reach the boron precipitation point and impede core cooling flow. The Westinghouse emergency core cooling system (ECCS) long-term core cooling model is used to confirm the existence of a coolable core geometry by establishing HLSO times which ensure that boron precipitation does not occur.

Once realigned to hot leg recirculation, boron precipitation is precluded and core cooling is assured by established minimum recirculation flow criteria for the hot legs, cold legs, or simultaneous hot and cold leg injection, such that all 10 CFR 50.46 criteria continue to be met.

Recirculation sump and hot leg switchover, and the methodology used to account for boric acid buildup during long-term core cooling are discussed below for the cold leg and hot leg recirculation.

<u>Cold Leg Recirculation - Hot Leg Break</u>
During sump recirculation for a hot leg break LOCA, all ECCS injection flow will feed the downcomer thus assuring that the cold leg break postulated by the LBLOCA analysis remains limiting. Cold leg injected flow provides forced flow through the core and out the hot leg break, thus assuring no increase in boron concentration in the core.

<u>Cold Leg Recirculation - Cold Leg Break</u>
During sump recirculation for a cold-leg break LOCA, ECCS injection flow in excess of that needed to keep the downcomer full will circulate around the top of the full downcomer and out of the broken cold leg. Core cooling is assured since the downcomer remains full and core peak clad temperature (PCT) continues to decrease as indicated in the LBLOCA analysis. Flow stagnation in the core together with core boiloff results in increased boron concentration in the core region. Boron precipitation is precluded by the realignment of ECCS injection to the hot legs prior to the boric acid solubility limit

<u>Hot Leg Recirculation (Simultaneous Hot Leg and Cold Leg Recirculation)</u>
At the IP2 EOP-designed hot leg switchover time, ECCS is aligned to provide simultaneous injection to both the cold legs and the hot legs. In the case of a cold leg break the hot leg injected flow provides forced flow through the core and out the cold leg break. In the case of a hot leg break, cold leg injected flow provides forced flow through the core and out the hot leg break. Forced flow through the core dilutes the highly borated core region for the cold leg break

case (where the boron concentration increases prior to hot leg switchover) and assures no further increase in core boron concentration for either a cold leg or hot leg break. In the simultaneous hot leg and cold leg alignment, both hot leg and cold leg flows are confirmed to exceed core boiloff so as to ensure core cooling and establish forced flow though the core.

Hot Leg Switchover Time
IP2 was licensed with a hot-leg switchover (HLSO) time supported by generic calculations that used common assumptions for 4-loop plants. With respect to core power, the generic calculations assumed a core power that conservatively bounds IP2 at the new power level including the new power uncertainty. On this basis, the HLSO licensing basis remains unchanged and the IP2 HLSO time is not impacted ('Unaffected', as listed in Table 8-1 of Attachment III of the license amendment request). The required HLSO time is reflected in the current IP2 operating procedure ES-1.4, Transfer to Hot Leg Recirculation.

Question 8:

For LOCA and non-LOCA transients and accidents that already assume 2 percent uncertainty in the current safety analysis, please provide discussion on the effects of the change of initial plant conditions for the power uprate to the results of these analyses.

Response 8:

The current UFSAR Chapter 14 safety analyses that bound the 1.4% power uprate already assume a 2% uncertainty on power. These events are delineated in Table 8-1 of Attachment III of the license amendment request. As discussed in Section 8 of Attachment III these transients did not require explicit re-analyses for the 1.4% uprate because the power level assumed in the current analyses is equivalent to the 1.4% uprated power of 3114.4 MWt plus 0.6% uncertainty. The other NSSS design parameters that changed are the vessel inlet (cold-leg) and outlet (hot-leg) temperatures and the steam pressure. However, the related changes to the hot-leg and cold-leg temperatures were an increase and decrease by about 0.5°F, respectively, and the steam pressure decreased by less than 10 psi. These condition changes were evaluated and determined to have an insignificant effect on the results of the current safety analyses. The current safety analysis basis was maintained for design parameters such as, reactor coolant system thermal design flow, Thot, Tcold and Steam Generator Tube Plugging. Therefore, the 1.4% power uprate has no effect on the results of the current IP2 safety analyses that already assume a 2% uncertainty on power.

Question 9:

Section 8.3.4.2 of the report indicated that loss of flow and locked rotor events were evaluated with respect to departure from nucleate boiling ratio (DNBR). Your evaluation concluded that the existing statepoints for these events remain valid with the exception of the nominal core heat flux, which increases due to the power uprate. Therefore, the higher nominal core heat fux must be applied to the power statepoints. The analyses with the revised statepoints showed that the DNB design basis remains satisfied. Please provide more details of these evaluations/ analyses including the calculated minimum DNBR for these events.

Response 9:

As described in Section 8.3.4.2 of Attachment III of the license amendment request, the minimum DNBR values for the complete loss of flow and reactor coolant pump (RCP) shaft seizure analyses were calculated as 1.762 and 1.536, respectively using the WRB-1 DNB correlation. The minimum DNBR of 1.762 for the complete loss of flow, for the 1.4% power uprate conditions, is still greater than the Safety Analysis Limit (SAL) DNBR of 1.58. However, the calculated minimum DNBR of 1.536 for RCP shaft seizure becomes slightly lower than before.

For the RCP shaft seizure event, Westinghouse used available DNBR margin between the SAL DNBR and the Design Limit DNBR (i.e., 1.26 typical cell and 1.25 thimble cell) to offset the small DNBR penalty of 0.044. As long as the Design Limit DNBR values (1.26 and 1.25) are not exceeded, there are no rods calculated to be in DNB for this event. The DNBR margin is tracked each cycle to ensure the design limit is met. The DNB design basis for the 1.4% power uprate was satisfied with sufficient DNBR margin between SAL DNBR and the Design Limit DNBR. The SAL DNBR of 1.58 remains unchanged in FSAR Chapter 14.

Question 10:

Section 8.3.6.5 of the report indicates that the Excessive Load Increase event was evaluated to demonstrate that the DNB design limit is met. Please provide details of this evaluation.

Response 10:

According to Westinghouse methodology, evaluations were performed for cases at Beginning-of-Life (BOL) and End-of-Life (EOL) conditions with and without automatic rod control. These evaluations were performed by applying conservative bounding deviations in plant parameters to initial conditions for core power, average coolant temperature, and RCS pressure in order to generate limiting statepoints for each of the cases examined. The bounding statepoints were then compared to the revised core thermal safety limits for the 1.4% power uprate to determine if the statepoints violated the safety limit conditions. From this comparison, it was determined that the core thermal limits were not violated. Therefore, the results of this evaluation concluded that the minimum DNBR safety analysis limit was not violated for the 1.4% power uprate for any of the cases examined.

Question 11:

Provide a quantified evaluation of the impacts of the 1.4 percent power uprate on the ability of IP2 to cope with a Station Blackout event.

Response 11:

The assessment of Station Blackout coping capability at the current power rating (3071.4 MWt) has been included in previous submittals to the NRC, as documented in the NRC's "Safety

Evaluation of the Indian Point Nuclear Generating Unit No. 2, Response to the Station Blackout Rule (TAC NO. M68556)," dated November 21, 1991. The following topics have been addressed.

1) Condensate inventory for decay heat removal
2) Class 1E battery capacity
3) Compressed air
4) Effects of loss of ventilation
5) Containment isolation

The following is a discussion of the impact of the 1.4% power uprate (3114.4 MWt) on the plant capabilities for coping with a station blackout event for each of these topics.

1. <u>Condensate Inventory for Decay Heat Removal</u>

For the current power rating (3071.4 MWt), the stated volume of water required for 8 hours of decay heat removal and primary system cooldown is 142, 850 gallons. For the 1.4% power uprate (3114.4 MWt), a small increase (less than one percent) in this volume has been determined to be required. Since the plant Technical Specifications require that a minimum of 360,000 gallons of water must be available in the Condensate Storage Tank (CST) during plant operation above 350°F, there continues to be a large margin between the minimum required volume of water in the CST and the volume of water required for coping with a station blackout event.

2. <u>Class 1E Battery Capacity</u>

For the current power rating it has been documented that, based on calculations, there is sufficient battery capacity for coping with a station blackout for one hour. An evaluation of the expected shutdown loads following a plant trip and loss of AC power at 1.4% power uprate conditions shows no increase in load on the station batteries. Accordingly, there is no change in the ability of IP2 to cope with a station blackout event under the 1.4% uprated conditions.

3. <u>Compressed Air</u>

The previous submittals have documented that the air operated valves needed to cope with an SBO event: (1) can be operated manually, (2) have sufficient backup sources independent of AC power for a one-hour coping duration, (3) have no air requirement (the normal and failed positions are the same as the desired SBO positions), or (4) fail in the desired SBO positions. The 1.4% power uprate will have no effect on air operated valve operation as described above during an SBO event.

4. <u>Effects of Loss of Ventilation</u>

The existing Station Blackout Analysis discussed in the above referenced SER identified only one dominant area of concern IAW the criteria of NUMARC 87-00 namely, the AFW pump room. The relevant inputs and assumptions used to analyze this space bounds the process conditions identified for the 1.4% power uprate. As a case in point, Main Steam temperatures are well within the margin of temperatures used in the AFW loss of ventilation scenario. The inputs and assumptions for the other spaces discussed in the loss of ventilation analysis are not impacted by the 1.4% power uprate.

5. Containment Isolation

It has been documented that containment isolation valves needed for containment isolation were reviewed to verify that valves which must be capable of being closed or that must be operated under SBO conditions can be positioned with indication independent of the preferred and Class 1E power supplies. Containment isolation valves needed to maintain containment integrity are closed and locked and/or sealed and covered administratively. The 1.4% power uprate will have no affect on this evaluation.

Question 12:

Describe the method used for determining the proposed maximum allowable power range neutron flux high setpoints for various number of inoperable main steam safety valves.

Response 12:

The maximum allowable power range neutron flux high setpoint is calculated to ensure that sufficient heat removal capability exists, based on the lowest total steam flow capacity available, when one or more main steam safety valves (MSSVs) are inoperable. An algorithm is used to calculate the high neutron flux setpoints based on the NSSS power rating of the plant, minimum total steam flow rate capability of the operable MSSVs (per steam generator times the number of loops), and the heat of vaporization at the highest MSSV opening pressure. The lowest steam flow available from the operable valves and the lowest heat of vaporization at the highest set pressure are used to provide the most conservative setpoint values. The high neutron flux setpoints calculated are then adjusted (9% lower) to account for instrument and channel uncertainties. As NSSS power rating is proposed to be increased for IP2, these setpoints have been updated.

The minimum total steam flow rate capability of the operable MSSVs is calculated based on the capacity of each MSSV (per steam generator) at the highest MSSV opening pressure, including tolerance and accumulation. Of the calculated capacity for each MSSV, the lowest steam flow rates from the lowest number of MSSVs operable are combined to determining the minimum total steam flow rate capable for steam relief per steam generator. For example, if the maximum number of inoperable MSSVs on any one steam generator is one (of 5 MSSVs), then the minimum total steam flow rate capability is the summation of the total capacity of all MSSVs at the highest operable MSSV operating pressure, excluding (less) the highest capacity MSSV.

Question 13:

In the first paragraph of Section 3.5, ENO stated that the LEFM Check System was originally installed in 1980 and the upgrade to the electronic unit, which meets the requirements of the approved Topical Report ER-80P, was installed in October 2002. The second paragraph of this section states that the Caldon LEFM Check System was installed in the fall of 2002. Please explain how the LEFM hardware (spool piece, etc) installation requirements of ER-80P was met in 1980 while ER-80P was approved in 1999. Also, please identify and explain if there was any failure of the LEFM system or its component since its original installation at IP2.

Response 13:

Response contains proprietary information, refer to separate Enclosure.

Question 14:

In Section 3.6, ENO stated that uncertainty calculations have been performed and determined a mass flow accuracy of better than 0.5 percent of rated flow for IP2. Please submit this calculation for staff review. Additionally, the instrument uncertainty of feedwater flow used in WCAP-15904-P is much lower (proprietary) than the calculated value determined to be better than 0.5 percent of rated flow. It is noted that the instrument uncertainty of feedwater flow used in power calorimetric uncertainty calculation for IP3 (WCAP-15824) was much higher (proprietary) than the calculated value (proprietary) provided in the ENO letter to the NRC, dated November 20, 2002. It is not clear why IP3 power calorimetric calculations used much higher than the calculated value of the LEFM measurement uncertainty while a similar calculation for IP2 used much lower than the calculated 0.5 percent, which makes it non-conservative. Please explain.

Response 14:

Response contains proprietary information, refer to separate Enclosure.

Question 15:

Section 3.3 provides justification for continued operation of IP2 at the power level of the proposed uprate power with an LEFM Check System out of service. In this section, it is stated that IP2 is operated based on alternate plant instrument, which is benchmarked to the LEFM's last good reading as soon as the LEFM Check System becomes unavailable. This alternate instrumentation has been subject to programmatic, extensive trending relative to LEFM flow and temperature outputs. This section also states that while the accuracy of the alternate instruments may degrade over time, it is considered likely that any degradation as a result of nozzle fouling, drift, and the like, would be imperceptible for the 7-day period as long as steady state conditions persist. Extrapolating from the programmatic trending data, or otherwise, please quantify the effects of the nozzle fouling and drift in terms of the percent uprate power during the proposed 7-day allowed outage time of an inoperable LEFM.

Response 15:

The data related to the relationship between the LEFM feedwater flow and the Venturi feedwater flow has been reviewed over a several month period. The average ratio, when examined over any particular seven day interval, typically varies by approximately 0.2% or less, and displays no discernable pattern or drift, but appears to vary randomly. Therefore, if the LEFM fails, we could be relatively certain that a calorimetric based on the Venturi feedwater flow would be accurate for a seven day period with an adjustment factor based on the preceding data. The Unit 2 Plant Computer software automatically performs the calculation based on the Venturi information, and recent LEFM-to-Venturi data.

When the Plant Computer executes the Heat Balance software, it determines if the LEFM inputs are reliable, based on the status flags transmitted from the LEFM to the Plant Computer via the dedicated datalink. If the LEFM feedwater flow data is reliable, then it is used to calculate the reactor power level, and also to calculate the LEFM/Venturi feedwater flow correction factors which are saved to be used in the event that unreliable LEFM inputs are encountered for the next periodic Heat Balance calculation. If the LEFM inputs are found to be unreliable, then the Heat Balance calculation is conducted with the corrected (with the previously calculated LEFM/Venturi feedwater flow correction factors) Venturi feedwater flow values.

Question 16:

In Section 3.7, ENO stated that loops 21 and 22 LEFM Check Systems were calibrated at Alden Research Laboratory while loops 23 and 24 calibration coefficients are based upon ARL testing of a population of 7 flow elements with similar inside diameters and dimensions. It is assumed that the ARL calibration of loops 21 and 22 LEFM was performed on the plant-specific piping configuration. Please confirm. Staff review of the ARL report of loops 21 and 22 LEFM calibration and loops 23 and 24 LEFM measurement uncertainty calculations, similar to the one submitted in your letter to the NRC dated November 20, 2002, for IP3, is needed to complete our evaluation of the proposed power uprate of IP2.

Response 16:

Response contains proprietary information, refer to separate Enclosure.

Question 17:

In Section 3.4, ENO stated that all other instrument components that provide fluid condition data for calculation of rated thermal power is controlled, calibrated, and performance monitored to the conditions represented in the overall calorimetric uncertainty evaluation done for the IP2 1.4 percent power uprate. Please confirm IP2 plant procedures for these actions that address all five items of section 1.1.F in RIS 2002-03.

Response 17:

In addition to the LEFM, which is the source for the Main Feedwater Mass Flows and Temperatures (4 individual monitored feedwater lines), the following additional instrumentation loops are employed for active input to the Power Calorimetric Algorithm:

1) Main Steam Pressures (3 instrument loops per line for a total of 12 inputs)
2) Calorimetric Main Feedwater Pressures (one instrument per line for a total of 4 inputs)
3) LEFM Main Feedwater Pressures (one instrument per line for a total of 4 inputs)
4) Steam Generator Blowdown Flows (one instrument per SG, total of 4 inputs)

All of the listed loops are hard-wired and deliver their respective values to the plant computer system for input to the calorimetric algorithm. The exceptions are the blowdown flows which are entered into the plant computer by the control room operators.

All of the listed instruments are calibrated in accordance with plant procedures, as elaborated above. Acceptance criteria is provided to trigger evaluation of test failures by way of the

Corrective Action process. These instruments will be added to the IPEC Performance Monitoring Program as part of the implementation of the Appendix K Power Uprate.

Changes to hardwired and software-based equipment at IP2 is accomplished under Engineering Change process procedures that are designed to conform to 10CFR50 Appendix B. The top tier procedure is DE-SQ-12.601. Additional controls on software are contained in Entergy's Software Quality Assurance Program (ENN-IT-104), which addresses development, testing, implementation, cataloging, modifying and retiring the plant's software based functions.

Equipment failures are documented by way of the Corrective Action process as defined in procedure ENN-LI-102 "Corrective Action Process". Failures are reviewed, appropriate corrective actions assigned, and corrective actions are tracked to completion.

Reportability of deficiencies is addressed through the Corrective Action Process (procedure ENN-LI-102). The requirements for reportability are contained in IP2 procedure SAO-125 "Station Written Report Requirements".

Manufacturer deficiency reports are received by the IPEC Operating Experience group, who then initiates the Corrective Action process to quickly determine applicability to IP2. Evaluation is then performed and appropriate corrective actions, as necessary, are assigned. The governing procedures are ENN-LI-102 and ENN-OE-100 "Operating Experience Program".

Question 18:

Provide in detail the effect of the power uprate on the environmental qualification of electrical equipment.

Response 18:

Environmental Qualification of electrical equipment was evaluated for the 1.4% power uprate. Equipment inside Containment was qualified to accident conditions for a Loss of Coolant Accident(LOCA) at a power level which bounds the 1.4% power uprate. Equipment outside containment was qualified to accident conditions resulting from High Energy Line Breaks (HELB's) in the following areas:

Steam and Feedline Penetration Area
Auxiliary Feed Pump Room
Primary Auxiliary Building (PAB)/Pipe Penetration Area (PPA)

The proposed 1.4% power uprate does not create any new high-energy lines. Lines in which 1.4% power uprate conditions are less severe then current operation (i.e., temperature and pressure decreases) are considered acceptable for the uprate. For systems that are considered "Unaffected" by the 1.4% power uprate, the current HELB analysis is also considered "Unaffected". The Steam and Feedline Penetration Area is subject to various HELB's of steam lines. These were performed at a power level which bounds the 1.4% uprate power and accounts for the effects of superheated steam. The HELB's in the Auxiliary Feed Pump Room and the PAB/PPA were performed assuming saturated steam at 1100 psia, which bounds the 1.4% power uprate conditions.

Question 19:

Provide details about the grid stability analysis including assumptions and results and conclusions for the power uprated condition.

Response 19:

The grid stability analysis is included in the vendor report (PowerGEM Report 10004.002-2), entitled "Study Report, Indian Point #2 Power Uprate: Transmission System Impact". The study concluded that system stability is not adversely affected by the uprate.

Stability data used in the study were provided by the NY-ISO and are from their 2001 Annual Transmission Reliability Assessment (ATRA) of the projected 2006 system. A 2006 summer peak case was used for the stability simulations to assess the effect of the proposed uprate of IP2 from 1020 MW to 1042 MW.

IP2 terminal voltage of 100%, relatively low local system voltages, and relatively high interface transfer levels provided a stressed system for the simulations. The Generator Step-up (GSU) transformers were loaded to 99.2% and 101.1% of the GSU transformer 542 MVA 55° C rating for pre-uprate and post-uprate conditions respectively.

Two contingencies were simulated for each case, to assess the effect of the incremental increase in IP2 generation from 1020 MW to 1042 MW.

Stability plots compared the response of several IP2 generator variables before and after the uprate, as well as selected 345 kV voltages.

The study concluded, "The system is shown to be stable for both contingencies, and the plots indicate a very similar response at IP2 before and after the uprate. The effect of the uprate on 345kV voltages is also negligible in both cases."

Question 20:

In Section 7.4.1, Fatigue evaluation has not been performed for RCL piping except the pressurizer surge line because then Code B31.1-1955 did not require such evaluation. Please explain why the evaluation is not applicable to the power uprated conditions given the fact the later ASME Section III Code requires such evaluation.

Response 20:

As stated in section 7.4.1 of Attachment III of the submittal, the code of record for the RCL piping analysis as documented in the latest analysis of record is USAS Code B31.1-1955. However, the Design Basis analysis was performed to the requirements of the 1973 edition of the B31.1 Code. Per the B31.1 Code, a detailed fatigue evaluation is not required for the RCL piping and therefore has not been performed. As discussed in Section 7.4.1, the uprate changes were evaluated for the RCL piping without impacting the design basis results. As such, there was no need to perform a reanalysis and no opportunity to upgrade code requirements. However, even if a RCL piping reanalysis were required, a fatigue evaluation would not typically be performed for IP2, since there is no NRC position requiring such an upgrade (i.e., to adhere to code requirements beyond those in the code of record) for RCL piping. This scenario differs from the situation for the pressurizer surge line.

The Pressurizer Surge line was evaluated to the ASME B&PV Section III, Subsection NB 1986 Code, and includes the effects of thermal stratification as stipulated in NRC Bulletin 88-11 and a detailed fatigue evaluation. This is due to NRC Bulletin 88-11, which states:

> "... licensees of plants in operation over 10 years (i.e., low power license prior to January 1, 1979) are requested to demonstrate that the pressurizer surge line meets the applicable design codes* and other FSAR and regulatory commitments for the licensed life of the plant, considering the phenomenon of thermal stratification and thermal striping in the fatigue and stress evaluations."
>
> "*Fatigue analysis should be performed in accordance with the latest ASME Section III requirements incorporating high cycle fatigue."

As a result of NRCB 88-11, the analysis code of record for the surge line only was required to be updated to incorporate detailed fatigue evaluations.

Question 21:

In reference to Section 7.4.2 of Attachment 3 to the amendment request, you stated that the 1.4 percent power uprate does not significantly affect any of the loads applied to the reactor coolant loop piping, steam generator and reactor coolant pump supports resulting from the Snubber Reduction Program. Therefore, you concluded that the design basis of the supports as reconciled for the IP2 Snubber Reduction Program remains applicable for the 1.4 percent power uprate. Provide a technical basis or quantitative evaluation for your conclusion. Also, confirm that the existing design basis analysis support loads has sufficient safety margin to accommodate the load increase due to the proposed 1.4 percent power uprate at IP2.

Response 21:

The RCL piping stress analysis results from IP2 Snubber Reduction Program shows that there is adequate amount of margin available for the piping stresses. This conclusion is based on a detailed review of all the key inputs to the RCL piping analysis. The key inputs to the RCL piping analysis include:

- RCL deadweight analysis,
- Seismic analysis,
- LOCA analysis,
- RCL thermal analysis,
- NSSS Design transients

There is no impact on the RCL deadweight analysis, seismic analysis, and LOCA analysis due to the 1.4% uprate. Further, there are no changes in the NSSS Design transients associated with the RCL (see Section 5.1.2 of Attachment III of the submittal). Finally, the impact on the

RCL thermal analysis due to the 1.4% uprate program conditions is insignificant, as demonstrated in the table below.

Comparison of Hot Leg, Cross-Over Leg and Cold Leg Temperatures for IP2 RCL

	Current Analysis Temperature (Snubber Reduction)	Uprate Conditions – Low Tavg Case	Uprate Conditions – High Tavg Case
TEMPERATURE, °F			
Hot Leg	611.7	583	611.7
Cross-Over Leg & Cold Leg	547.4	515.5	546.4
TEMPERATURE CHANGE, %			
Hot Leg	N/A	-5.3	0
Cross-Over Leg & Cold Leg	N/A	-6.68	-0.21

Thus, the parameters of the 1.4% uprating program have no significant effect on the analysis of the RCL piping system including the associated primary equipment nozzles and primary equipment supports.

Therefore, the RCL piping analysis, the primary equipment support analysis, and the primary equipment nozzle loads in the IP2 Snubber Reduction Program remain valid for the 1.4% power uprate program. Additionally, since there is no significant impact on the RCL analysis, there is no change to the LBB loads on the RCL.

Question 22:

In reference to Table 7-6, "IP2 1.4% Power Uprate Evaluation Summary; Primary-and-Secondary-Side Components," you indicated that for tube and tubesheet weld, the reference analysis used conservative high fatigue strength reduction factor with elastic stresses in the fatigue evaluation since primary stresses exceed 3Sm. Provide a summary describing the reference analysis and the high fatigue strength reduction factor that was used in the analysis. Also, provide the existing design basis stresses and the calculated stress at the uprated condition, that are not shown in the table, for the tube to tube-sheet weld, the divider plate and the tube-sheet/shell junction.

Response 22:

In the tube-to-tubesheet weld area, the primary plus secondary stress intensity range exceeded the 3Sm limit requiring consideration of plastic strain in the fatigue usage calculations. This would usually involve complex elastic-plastic analysis. In order to develop a simplified approach, Westinghouse had conducted some analytical experiments by comparing two separate approaches as indicated below:

The first approach considered an elastic analysis model with a stress concentration factor of 4.0 applied to the linearized in-plane stresses and a factor 1.215 applied to the tangential stresses. These stresses were then used in the calculation for fatigue usage.

The second approach considered a simplified elastic-plastic analysis model where the tangential strains were augmented by a factor of 1.215. The effective uniaxial strain at any location of interest was then obtained and modified Poisson's ratio was calculated. Stresses obtained from these were then used to calculate the fatigue usage.

It was discovered that the first approach is conservative at the weld surface while the second approach is conservative for the weld root. However, fatigue at the weld root can also be conservatively calculated if the elastic analysis model was used with a stress concentration factor of 5.0 applied to the linearized in-plane stresses and a factor 1.519 applied to the tangential stresses.

The analysis results presented here used the elastic analysis approach using conservative stress concentration factors to account for plastic strain effects on fatigue usage calculation. The originally calculated maximum fatigue usage factor 0.072 occurring at the weld surface and presented in Table 7-6 included the plastic strain effects through the use of conservative stress concentration factors: 4.0 for linearized in-plane stresses and 1.215 for the tangential stresses.

For uprating evaluation, the above fatigue usage value was augmented toa value of 0.086 after accounting for increased stress ranges at various load combination states.

The requested design basis stresses and calculated uprate stresses are shown in thefollowing revised version of Table 7-6.

Table 7-6 (Rev 1)

Indian Point 2 1.4% Uprate Evaluation Summary

Primary and Secondary Side Components

Component	Load Condition	Stress Category	Stress (ksi)/ Fatigue - Baseline	Stress (ksi)/ Fatigue - Uprate	Allow (ksi/ Fatigue	Comments
Primary Side Components						
Divider Plate	Normal / Upset	Pm+Pb+Q [6]	73.48 [6]	73.48 [6]	69.90	Plastic analysis performed
		Fatigue	0.664	0.786	1.00	
Tubesheet & Shell Junction	Normal / Upset	Pm+Pb+Q	88.7 [7]	88.7 [7]	80.10	
		Fatigue	0.356	0.482	1.00	
Tube to Tubesheet weld [2]	Normal / Upset	Pm+Pb+Q [2]	148.5 [2]	167.66 [2]	79 8	Ref analysis used higher factors with elastic stresses
		Fatigue	0.072	0.086	1.00	
Tubes	Normal / Upset	Pm+Pb+Q	59.77	59.77 [8]	79.8	
		Fatigue	0.142	0.191	1.00	
Secondary Side Components[1]						
Main feed water nozzle	Normal/ Upset	Pm+Pb+Q	76.02	76.11	80 10	
		Fatigue	0.994	1.000	1.00	
Secondary manway stud	Normal/ Upset	Pm+Pb+Q	80.20	80.79	94.5 ($2.7S_m$)	
		Fatigue	0.665	0.710	1.00	
Steam Nozzle [3]	Normal/ Upset					
Sec A-A		Pm+Pb+Q [3]	57.96	58.14	80 10	
Insert section 2 [4]		P_m+P_b+Q [4]	62.97 [4]	63.346[4]	56 07	simplified Plastic analysis done
Support ring (Sec A-A) [5]		P_m+P_b+Q [5]	46.527 [5]	46.64 [5]	36 50	simplified Plastic analysis done
		Fatigue(A-A) inside	0 020	0 024	1.00	
		Nozzle insert	0 865	0.870	1.00	
		Support ring (Sec A-A) [3]	0 190	0.192	1.00	

Table 7-6 (Rev 1), continued

Indian Point 2 1.4% Uprate Evaluation Summary

Primary and Secondary Side Components

Note 1: Additional stress due to reduction of pressure is taken to calculate the increase in stress range for secondary side components

Note 2: Conservative stress concentration factors are used with elastic stresses in the fatigue evaluation since primary stresses exceed 3Sm.

Note 3: Steam Nozzle (Sec A-A)-Additional Pressure Stress-(10/1357)x24.87=0.183 ksi
Steam Nozzle(Insert)-Additional Pressure Stress- (10/1357)x 50.27=0.464 ksi
Steam Nozzle (Support Ring)Additional pressure stress : (10/1357)x15.706=0.115 ksi
[Table 6-13 Vol 10-WNEP 8733]

Note 4: Exceeds $3S_m$. Simplified plastic analysis was done in the reference analysis for fatigue evaluation.

Note 5: Exceeds $3S_m$. Simplified plastic analysis was done in the reference analysis for fatigue evaluation.

Note 6: Exceeds $3S_m$ Simplified plastic analysis was done in the reference analysis for fatigue evaluation.

Note 7: Exceeds 3Sm Simplified plastic analysis was done in the reference analysis for fatigue evaluation.

Note 8: Values not affected by Uprate.

<u>Question 23</u>:

In reference to Section 10.9, "Balance-of-Plant (BOP) Piping and Support Evaluation," you indicated that the changes in operating parameters such as temperature, pressure, and flow rate were determined to be insignificant and you concluded that they have a negligible effect on the existing piping system qualifications. No specific pipe stress re-analysis were required to document the acceptability of the 1.4 percent power uprate conditions. Provide a summary of your quantitative evaluation to demonstrate that there exist sufficient safety margins to accommodate the changes due to the proposed power uprate on the Balance-of-Plant piping and supports.

<u>Response 23</u>

The following provides a summary of the evaluations that were performed to document Balance of Plant (BOP) pipe stress and support acceptability for power uprate conditions.
Pre-uprate and uprate system operating data (operating temperature, pressure, and flow rate) were obtained, and "Change Factors" were determined to evaluate the changes in operating conditions. These change factors were determined for both Tavg = 559°F and 562°F conditions. The operating data and resulting change factors for these two conditions were essentially the same, and the data for the Tavg = 562°F condition is presented in this response. The thermal, pressure and flow rate "change factors" were based on the following ratios:

- The thermal "change factor" was based on the ratio of the power uprate to pre-uprate operating temperature. That is, thermal change factor is $(T_{uprate}\text{-}70°F) / (T_{pre\text{-}uprate}\text{-}70°F)$.
- The pressure "change factor" was determined by the ratio of $(P_{uprate} / P_{preuprate})$.
- The flow rate "change factor" was determined by the ratio of $(Flow_{uprate} / Flow_{pre\text{-}uprate})$.

These thermal, pressure and flow rate change factors were used in determining the acceptability of piping systems for power uprate conditions.

For thermal, pressure, and flow rate change factors less than or equal to 1.0 (that is, the pre-uprate condition envelops or equals the power uprate condition), the piping system was concluded to be acceptable for power uprate conditions.
For thermal, pressure, and flow rate change factors greater than 1.0 and less than or equal to 1.05 (that is, a greater than zero and less than or equal to five percent increase in thermal expansion, pressure, and/or flow rate effects), this minor increase was concluded to be acceptable based on the following rationale. Certain levels of deviation from design basis conditions can be concluded to be permissible if that level of change would not alter the piping system results to an appreciable degree. Relatively small temperature changes can be concluded to be acceptable as the increase in pipe stresses, pipe support loads, nozzle loads, and piping displacements are correspondingly small and generally predictable. These increases are somewhat offset by conservatism in analytical methods used to calculate thermal and/or fluid transient stresses and loads. Conservatism may include the enveloping of multiple thermal operating conditions, as well as not considering pipe support gaps in thermal analyses. For supports installed on safety related systems which are evaluated for seismic loading effects, a

potential five percent increase in a specific thermal loading condition will generally result in a less than 5 percent overall pipe support design load increase due to the existence of seismic earthquake loads.

Using the methodology and acceptance criteria described above, detailed piping system evaluations were performed. A summary of these evaluations follows:

Main Steam and Steam Dump
The operating temperature and pressure did not increase as a result of power uprate. The main steam flow rate did increase from 13.26M #/hr to a power uprate value of 13.48M #/hr. This results in a flow rate change factor of (13.48/13.26) or 1.02, which was less than the 1.05 acceptance limit.

Condensate and Feedwater
The condensate and feedwater operating temperature and flow rate increased slightly as a result of power uprate, while the operating pressures decreased. A summary of the operating temperature increases including thermal "change factors" are provided in the following Table.

System Boundary	Pre-Uprate Temperature (°F)	Power Uprate Temperature (°F)	Thermal Change Factor
Condensate Pump Discharge to No. 21 Heaters	93	93	1.00
No. 21 Heaters to No. 22 Heaters	164	164	1.00
No. 22 Heaters to No. 23 Heaters	198	198	1.00
No. 23 Heaters to No. 24 Heaters	250	251	1.01
No. 24 Heaters to No. 25 Heaters	301	302	1.00
No. 25 Heaters to Boiler Feed Pump	388	388	1.00
Boiler Feed Pump to No. 26 Heaters	390	391	1.00
No. 26 Heaters to Steam Generators	427	429	1.01

Since the maximum temperature increase for is only 2°F, and the maximum thermal change factor is 1.01 which is less than the 1.05 acceptance limit, the temperature increases summarized above were concluded to be acceptable.

The flow rate for the condensate and feedwater systems increased from 13.31M #/hr to 13.52M #/hr which results in a "change factor" of 1.02, which is less than the 1.05 acceptance limit.

Extraction Steam

The extraction steam system operating temperature, pressure and flow rate increased slightly as a result of power uprate. A summary of these data including applicable "change factors" is provided in the following Table.

System Boundary	Operating Parameter	Pre-uprate	Power Uprate	Change Factor
Extraction Steam at Inlet to No. 21 Feedwater Heaters	Temperature (°F)	169	169	1.00
	Pressure (psia)	5.8	5.8	1.00
	Flow Rate (#/hr)	746,700	756,400	1.01
Extraction Steam at Inlet to No. 22 Feedwater Heaters	Temperature (°F)	201	201	1.00
	Pressure (psia)	11.8	11.8	1.00
	Flow Rate (#/hr)	447,700	444,300	0.99
Extraction Steam at Inlet to No. 23 Feedwater Heaters	Temperature (°F)	254	254	1.00
	Pressure (psia)	32	32	1.00
	Flow Rate (#/hr)	592,400	589,800	1.00
Extraction Steam at Inlet to No. 24 Feedwater Heaters	Temperature (°F)	306	307	1.00
	Pressure (psia)	73	74	1.01
	Flow Rate (#/hr)	549,400	560,700	1.02
Extraction Steam at Inlet to No. 25 Feedwater Heaters	Temperature (°F)	394	395	1.00
	Pressure (psia)	219	222	1.01
	Flow Rate (#/hr)	1,132,000	1,123,000	0.99
Extraction Steam at Inlet to No. 26 Feedwater Heaters	Temperature (°F)	440	442	1.01
	Pressure (psia)	363	370	1.02
	Flow Rate (#/hr)	587,700	552,000	0.94

A review of the data reveals that the maximum temperature, pressure and/or flow rate change factor is 1.02, which is less than the 1.05 acceptance limit.

Feedwater Heater/Moisture Separator Reheater Drains

The feedwater heater/moisture separator reheater drain system existing operating temperatures, pressures and flow rates increased slightly as a result of power uprate.

A summary of the operating temperature increases including applicable "change factors" is provided in the following Table.

System Boundary	Pre-Uprate Temperature (°F)	Power Uprate Temperature (°F)	Thermal Change Factor
Drains from No. 21 Heaters to Condenser	103	103	1.00
Drains from No. 22 Heaters to No. 21 Heaters	174	174	1.00
Drains from No. 23 Heaters to No. 22 Heaters	208	208	1.00
Drains from No. 24 Heaters to No. 23 Heaters	260	260	1.00
Drains from No. 25 Heaters to Drain Tank	390	391	1.00
Drains from No. 26 Heaters to Drain Tank	400	401	1.00
MSR Drains to Drain Tank	391	392	1.01

Since the maximum temperature increase is only 1°F, and the maximum thermal change factor is 1.01 which is less than the 1.05 acceptance limit, the temperature increases summarized above were concluded to be acceptable.

The maximum operating pressure increase for the heater drain piping is less than 12 psi, which does not significantly impact the existing piping system stress levels.

The various heater drain lines experience slight flow rate increases were all below the 1.05 acceptance limit.

Question 24:

In reference to Section 12.2.5, "Safety-Related Motor Operated Valves," you evaluated the effect of the proposed power uprate on the motor-operated valves (MOVs) program at Indian Point 2 (IP2) for Generic Letter (GL) 89-10 and GL 95-07 regarding pressure locking and thermal binding or safety-related power-operated gate valves. Provide a summary evaluation of the effects of the proposed power uprate on your response to GL 96-06 regarding overpressurization of isolated piping segment.

Response 24:

In September 1996, the NRC issued Generic Letter 96-06 to address (among other concerns) the concerns that thermally induced over-pressurization of isolated water-filled piping sections in containment could:

- Jeopardize the ability of accident mitigating systems to perform their safety functions
- Lead to a breach of containment integrity via bypass leakage

The accident pressure/temperature values are still bounded by design. Current accident analyses (LOCA) are bounding for the 1.4% power uprate condition, and there are no changes to CFC cooling water flow requirements or CFC accident conditions associated with the uprate. There is no increase in the possibility of over-pressurization of isolated segments of safety related piping inside containment, including penetrations, as a result of the 1.4% power uprate. Therefore, the GL-96-06 program is not affected by the uprate.

ENCLOSURES TO NL-03-058

1) Caldon, Inc. report ER-290, "Bounding Uncertainty Analysis for Thermal Power Determination at Indian Point Unit 2 Nuclear Power Station using the LEFM-Check System".
   [2 copies each, proprietary and non-proprietary versions]

2) MPR Associates, Inc. report MPR-1614, "Feedwater Flow Measurement with LEFM Chordal Systems at Indian Point Unit 2 – Configuration and Uncertainty Analysis", October 1995.
   [2 copies each, proprietary and non-proprietary versions]

3) Responses to Questions 13, 14, and 16 of the NRC Request for Additional Information.
   [2 copies each, proprietary and non-proprietary versions]

4) Alden Research Laboratory report ARL 106-79 / C91, "Calibration – Indian Point ; Two 18" Ultrasonic Flowmeters", May, June 1979. (not proprietary)

5) Caldon, Inc Authorization letter CAW 03-02 dated April 1, 2003, requesting withholding from public disclosure (with accompanying affidavit) for items 1, 2, and 3

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-247