FENOC

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December 2, 2005
L-05-177

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

Subject: **Beaver Valley Power Station, Unit Nos. 1 and 2**
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Responses to a Request for Additional Information (RAI dated November 1, 2005) in Support of License Amendment Request Nos. 302 and 173

On October 4, 2004, FirstEnergy Nuclear Operating Company (FENOC) submitted License Amendment Request (LAR) Nos. 302 and 173 by letter L-04-125 (Reference 1). This submittal requested an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 and is known as the EPU LAR.

On April 13, 2005, FENOC submitted LAR No. 320 for BVPS Unit No. 1 by letter L-05-069 (Reference 2). This submittal requested the Technical Specification changes necessary for operation of BVPS Unit No. 1 with the replacement steam generators and is known as the RSG LAR.

By letter dated November 1, 2005, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) pertaining to LAR Nos. 302 and 173 (Reference 1). It is noted that the November 1, 2005 RAI questions are applicable to both the RSG and EPU LARs.

Enclosure 1 contains the FENOC responses to the November 1, 2005 RAI questions, including the information proprietary to Westinghouse Electric Company LLC. The proprietary information in Enclosure 1 is identified with brackets.

Enclosure 2 contains the Non-Proprietary FENOC responses to the November 1, 2005 RAI questions. The proprietary information deleted from Enclosure 2 is identified with brackets.

Enclosure 3 contains an affidavit signed by Westinghouse, the owner of the proprietary information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the

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considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's regulations.

Enclosures 4 and 5 contain supplemental information requested during the November 7-9, 2005 EPU Calculation Audit and information requested during the November 16, 2005 telephone conference regarding Boron Dilution.

The responses and supplemental information provided by this transmittal have no impact on either the proposed Technical Specification changes or the no significant hazards consideration, transmitted by References 1 or 2.

Enclosure 6 discusses the commitments made in this transmittal. If you have questions or require additional information, please contact Mr. Gregory A. Dunn, Manager - Licensing, at 330-315-7243.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 2, 2005.

Sincerely,

James H. Lash

Enclosures:

1. Proprietary Responses to RAI dated November 1, 2005
2. Non-Proprietary Responses to RAI dated November 1, 2005
3. Westinghouse Affidavit CAW-05-2075
4. Boron Dilution Supplemental Information
5. Supplemental Information for Change to Technical Specification 3.4.1.3
6. List of Commitments

References:

1. FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.
2. FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Senior Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

Enclosure 2 of L-05-177

Non-Proprietary Responses to RAI dated November 1, 2005

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)

RELATED TO FIRSTENERGY NUCLEAR OPERATING COMPANY (FENOC)

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2)

EXTENDED POWER UPRATE (EPU)

DOCKET NOS. 50-334 AND 50-412

By letter dated October 4, 2004, as supplemented February 23, May 26, June 14, July 8, September 6, and October 7, 2005, Agencywide Documents Access and Management System, Accession Nos. ML051160426, ML042920300, ML051530376, ML051670270, ML051940575, ML052550373, and ML052850145, FENOC (the licensee) submitted a license amendment request for BVPS-1 and 2 to change the operating licenses to increase the maximum authorized power level from 2689 megawatts thermal (MWt) to 2900 MWt which represents an increase of approximately 8 percent above the current maximum authorized power level. The Nuclear Regulatory Commission (NRC) staff has reviewed the licensee's application against the guidelines in the EPU review standard (RS-001) and determined that it will need the additional information identified below to complete its review. These questions reference licensee's responses from the licensee's May 26, and July 8, 2005, RAI responses.

May 26, 2005, Second Round RAI Questions

1. Question

In response to the NRC staff's RAI Question No. N1, you indicated that the main steamline breaks and feedwater line breaks were not considered in the EPU analysis because the loss-of-coolant accident (LOCA) loads due to these breaks have no significant impact on the reactor vessel (RV) and internals. Confirm whether these LOCA loads at the EPU conditions are bounded by the original design-basis forcing functions. If not, justify not applying these loads to the dynamic model and evaluate the impact on the stresses and cumulative usage factor (CUF) calculations, especially for the steam generator internals, shell and supports.

Response:

In the response to RAI question N.1, the term "LOCA" is used to refer to pipe breaks in the primary reactor coolant system (RCS) piping, such as reactor coolant loop and pressurizer surge line breaks. The hydraulic forces associated with LOCA (i.e., time forcing functions) are prepared for these breaks in RCS piping. Pipe breaks in the main steam and feedwater lines are secondary side pipe breaks and are not included in the "LOCA" category of pipe breaks. LOCA hydraulic forces are not prepared for secondary side pipe breaks. Thus, "LOCA" pipe breaks and secondary side pipe breaks are addressed separately.

The structural analyses for the reactor vessel and internals include consideration of the applicable LOCA hydraulic forces and LOCA loads. The reactor vessel and internals structural analyses do not include consideration of secondary side pipe breaks since they are not limiting.

With respect to "LOCA" pipe breaks, the response to RAI question No. N.1 confirms that the current BVPS licensing basis is based on the application of Leak-Before-Break (LBB) technology, which excludes breaks in the reactor coolant loop and pressurizer surge line for BVPS-1 and breaks in the reactor coolant loop, pressurizer surge line, and reactor coolant loop branch lines down to and including the 6-inch safety injection lines for BVPS-2. The response describes the new LOCA hydraulic forces that were developed for the next most limiting RCS lines, which are the 12-inch accumulator line (cold leg) and 14-inch residual heat removal line (hot leg) for BVPS-1 and the 4-inch pressurizer spray line (cold leg) and 3-inch pressurizer PORV line (hot leg) for BVPS-2. The new LOCA hydraulic forces for BVPS-1 considered both the EPU and the RSG whereas the new LOCA hydraulic forces for BVPS-2 considered the EPU only. For BVPS-1, new LOCA hydraulic forces were developed for use in the structural analyses for the reactor coolant loop, the reactor vessel and internals, and the replacement steam generators. For BVPS-2, new LOCA hydraulic forces were developed for use in the structural evaluations for the reactor coolant loop and the structural analyses for the reactor vessel and internals. New LOCA hydraulic forces were not developed for the BVPS-2 steam generators. For the BVPS-2 steam generators, an evaluation was performed to show that the LOCA hydraulic forces for large reactor coolant loop and branch line breaks currently used in BVPS-2 steam generator analyses remain bounding for the small 4-inch spray line and 3-inch PORV line breaks at EPU conditions.

Question 2.

In your response to RAI Question No. N4, you described the dynamic model, method, and analysis in support of the EPU and replacement steam generators (RSGs) at BVPS-1. You also indicated that the results from the NUPIPE-SWPC analyses for the primary reactor coolant loop piping include loads on the major components, nozzles, and supports for the normal operating conditions, upset conditions, and the faulted LOCA conditions. These loads were used in the evaluations of the major components, nozzles, and supports (including the RSGs, reactor coolant pumps, and RV) and have been shown to be acceptable. You also indicated that the stresses and CUFs provided for BVPS-1 piping, components and supports, including the RV and internals, at the EPU conditions include the dynamic effect of the RSGs. However, in response to RAI Question No. N5, you indicated that:

> **"...the evaluation provided in Section 4.7.1 of the EPU Licensing Report is qualitative since, as stated in the introduction to this section, the licensing acceptability of replacing the Model 51 original SG components with Model 54F replacement SG components is being evaluated under the provisions of 10 CFR 50.59. [Title 10 of the Code of Federal Regulations (10 CFR), Part 50, Section 59]... The stress information requested is being generated as part of the design process for the BV-1 replacement steam generators. The information will be included in the Design Stress report. When completed, it will be available on-site for NRC review and inspection."**

Please explain the apparent discrepancy. The information that was requested in Question No. N5 for BVPS-1 is needed for the NRC staff to complete its evaluation. The

information requested is similar to that provided to support the BVPS-2 original SGs operating at the EPU conditions.

Response:

For BVPS-1, the Extended Power Uprate (EPU) License Amendment Request (LAR) No. 302 and the Replacement Steam Generator (RSG) LAR No. 320 report the results of the structural analyses performed for the reactor coolant loop and loop components (i.e., reactor vessel and internals, reactor coolant pumps, loop stop isolation valves), except for the replacement steam generators. The analyses reported in these LARs incorporate EPU conditions with the Model 54F steam generators. However, the structural analyses for the RSG components were not included in the EPU and RSG LARs since these analyses were still in process when the subject LARs were prepared and submitted to the NRC. The structural analyses for the RSG components were still in process when the subject RAI questions (including questions N.4 and N.5) were issued by the NRC on March 11, 2005 and when responses were provided by FENOC letter L-05-078, dated May 26, 2005. As noted in the response to RAI question N.5 (L-05-078, dated May 26, 2005), it was planned that the licensing acceptability of replacing the Model 51 original steam generators (OSGs) with Model 54F steam generators would be evaluated under the provisions of 10 CFR 50.59.

The information requested in RAI question N.5 (i.e., calculated stresses and CUFs for critical RSG components and flow-induced vibration evaluation results) is now available since the structural analyses for the RSG components have been completed. This information is provided herein.

Calculated Stresses and CUFs

The calculated stresses and CUFs for the critical BVPS-1 replacement SG shell, nozzles, internals, and U-bend tubes are provided in the following tables:

Table 1	Calculated Stresses and CUFs for Center of Tubesheet & Junction of Tubesheet and Channel Head
Table 2	Calculated Stresses and CUFs for Junction of Tubesheet and Lower Secondary Shell & Primary Nozzle
Table 3	Calculated Stresses and CUFs for Primary Nozzle – Safe End & Primary Manway
Table 4	Calculated Stresses and CUFs for Primary Manway Stud & Secondary Shell – Limiting Stress Ratios
Table 5	Calculated Stresses and CUFs for Steam Outlet Nozzle & Steam Outlet Nozzle – Safe End
Table 6	Calculated Stresses and CUFs for Feedwater Nozzle & Feedwater Nozzle Thermal Sleeve and Feedwater Distribution Ring
Table 7	Calculated Stresses and CUFs for Secondary Manway & Secondary Manway Stud
Table 8	Calculated Stresses and CUFs for Tube at Tubesheet & Tube in U-bend
Table 9	Calculated Stresses and CUFs for Tube to Tubesheet Weld & Primary Chamber Divider Plate
Table 10	Calculated Stresses and CUFs for Handhole and Inspection Port in Secondary Shell & Handhole and Inspection Port Bolt
Table 11	Calculated Stresses and CUFs for Primary Moisture Separator Assembly & Secondary Moisture Separator Assembly
Table 12	Calculated Stresses and CUFs Ratios for Lower Internals (Tube Support System)

Flow Induced Vibration Evaluation

The possibility of tube degradation due to either mechanical or flow-induced excitation in combination with corrosion potential was considered in the design of the BVPS-1 Model 54F steam generators. Detailed analyses of the tube support system reference results from an extensive research program with tube vibration model tests. Consideration was given to potential sources of tube excitation including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the tubes. However, effects of primary fluid flow and mechanically induced vibration are considered to be negligible during normal operation based on prior evaluations and extensive operating experience with similar designs. The primary source of potential tube degradation due to vibration is the hydrodynamic excitation by the secondary fluid on the outside of the tubes, and this area has been emphasized in both analyses and tests.

Three potential tube vibration mechanisms due to hydrodynamic excitation by the secondary fluid on the outside of the tubes have been identified and evaluated. These are flow-induced vibrations resulting from vortex shedding, turbulence, and fluid-elastic vibration mechanisms.

Non-uniform, two-phase turbulent flow exists throughout most of the tube bundle. Therefore, vortex shedding is possible only for the outer few rows in the inlet region. Moderate tube response caused by vortex shedding is observed in some carefully controlled laboratory tests on idealized tube arrays, but no evidence of tube response caused by vortex shedding is observed in steam generator scale model tests simulating the inlet region. In order to assure conservatism, bounding calculations consistent with laboratory test parameters were performed to confirm that vibration amplitudes would be acceptably small.

Flow induced vibrations due to flow turbulence are also small, and these vibrations cause bending stresses that are well below fatigue limits for the tubing material. Therefore, neither unacceptable tube wear nor fatigue degradation is anticipated due to secondary flow turbulence.

Fluid-elastic tube vibration is potentially more severe than either vortex shedding or turbulence because it is a self-excited mechanism: relatively large tube amplitudes can feedback proportionally large tube driving forces if an instability threshold is exceeded. Tube support spacing incorporated into design of both the tube support plates and the anti-vibration bars in the U-bend region provides tube response frequencies such that the instability threshold is not exceeded for secondary fluid flow conditions for tubes that are effectively supported. This approach provides large margins against initiation of fluid-elastic vibration for tubes that are effectively supported by the tube support system.

Small clearances between the tubes and supporting structure are required for steam generator fabrication. These clearances introduce the potential that any given tube support location may not be totally effective in restraining tube motion if there is a finite gap around the tube at that location. Fluid-elastic tube response within available support clearances is therefore theoretically possible if secondary flow conditions exceed the instability threshold when no support is assumed at the location with a gap around the tube.

This potential has been investigated both with tests and analyses for the U-bend region where secondary flow conditions have the potential to exceed the instability threshold if a tube does not contact nearby supports as a result of fabrication tolerances. Tube degradation attributed to vibration and wear in some Model 51 steam generators with two sets of conventional anti-vibration bars was shown to result from this fluid-elastic rattling mechanism. Replacement steam generators for BVPS-1 have advanced configurations with three sets of anti-vibration bars and other enhanced features. These same tests and analyses have been used to show that tube wear potential has been reduced by more than an order of magnitude by changes incorporated in the advanced Model 54F configuration as compared to the conventional Model 51 design.

Tube vibration response is shown to have wear potential within available design margins even for limiting tube-to-support fit-up conditions that were chosen to bound those resulting from controlled fabrication procedures. Analyses and tests for limiting postulated fit-up conditions include simultaneous contributions from flow turbulence. Corresponding tube bending stresses are shown to be well below fatigue limits as a consequence of small vibration amplitudes that result from the small clearances in the advanced design. This is true even for postulated clamped conditions associated with corrosion mechanisms that are unlikely for the 405 stainless steel supports in the Model 54F steam generator.

Table 13 contains summary results of the flow-induced vibration evaluation. Limiting conditions for the tube bundle are referenced on the table. Fluid-elastic stability ratios are much less than the theoretical threshold (1.0) and also less than the specified limit (0.75). Displacements and bending stresses from turbulence are small. The maximum calculated tube wear depth after 40 years of operation is about [ ]^{a,c} inches. Margins against rapidly propagating fatigue are also demonstrated subject to postulated conservative material/fit-up conditions. Postulated clamped tube support conditions with reduced damping and conservative high-cycle fatigue were evaluated to demonstrate that BVPS-1 Model 54F steam generators have large margins against the rapidly propagating fatigue event.

Analyses and tests therefore demonstrate that unacceptable tube degradation resulting from tube vibration is not expected for the BVPS-1 Model 54F steam generators with advanced U-bend/anti-vibration bar (AVB) configurations. Operating experience with similar F-type straight-leg tube supports and with field modifications to conventional Model 51 steam generators substantiates this conclusion.

Table 1
Calculated Stresses and CUFs for
Center of Tubesheet & Junction of Tubesheet and Channel Head

Loading Condition	Stress Category	Center of Tubesheet Stress (ksi)	Center of Tubesheet Allow (ksi)	Center of Tubesheet Ratio	Junction of Tubesheet and Channel Head Stress (ksi)	Junction of Tubesheet and Channel Head Allow (ksi)	Junction of Tubesheet and Channel Head Ratio
Design	P_m	[ ]^{a,c}	30.0	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	45.0	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	45.0	[ ]$^{a,c\,(1)}$	[ ]^{a,c}	45.0	[ ]$^{a,c\,(1)}$
Normal and Upset	$P_L + P_b + Q$	[ ]^{a,c}	90.0	[ ]^{a,c}	[ ]^{a,c}	90.0	[ ]^{a,c}
	Fatigue Usage	[ ]^{a,c}	1.00	[ ]^{a,c}	[ ]^{a,c}	1.00	[ ]^{a,c}
Faulted	P_m	[ ]^{a,c}	63.0	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	94.5	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	94.5	[ ]^{a,c}	[ ]^{a,c}	94.5	[ ]^{a,c}
Test	P_m	[ ]^{a,c}	54.95	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	82.42	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	82.42	[ ]^{a,c}	[ ]^{a,c}	82.42	[ ]$^{a,c\,(1)}$
	$P_L + P_b + Q$	[ ]^{a,c}	122.1	[ ]^{a,c}	[ ]^{a,c}	122.1	[ ]^{a,c}

Note:

1. **Loading does not exceed 2/3 of the lower bound collapse load (NB-3228.1). Both design and test stress values are acceptable.**

Table 2
Calculated Stresses and CUFs for
Junction of Tubesheet and Lower Secondary Shell & Primary Nozzle

Loading Condition	Stress Category	Junction of Tubesheet and Lower Secondary Shell			Primary Nozzle		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	n/a	n/a	n/a	[ ]^{a,c}	26.70	[ ]^{a,c}
	P_L	[ ]^{a,c}	40.05	[ ]^{a,c}	[ ]^{a,c}	40.05	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	40.05	[ ]^{a,c}	[ ]^{a,c}	38.14	[ ]^{a,c}
Normal and Upset	P_m	n/a	n/a	n/a	[ ]^{a,c}	29.37	[ ]^{a,c}
	P_L	n/a	n/a	n/a	[ ]^{a,c}	44.06	[ ]^{a,c}
	$P_L + P_b$	n/a	n/a	n/a	[ ]^{a,c}	41.96	[ ]^{a,c}
	$P_L + P_b + Q$	[ ]^{a,c}	80.1	[ ]^{a,c}	[ ]^{a,c}	80.10	[ ]^{a,c}
	Fatigue Usage	[ ]^{a,c}	1.00	[ ]^{a,c}	[ ]$^{a,c\,(1)}$	1.00	[ ]$^{a,c\,(1)}$
Faulted	P_m	n/a	n/a	n/a	[ ]^{a,c}	64.08	[ ]^{a,c}
	P_L	[ ]^{a,c}	84.0	[ ]^{a,c}	[ ]^{a,c}	84.00	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	84.0	[ ]^{a,c}	[ ]^{a,c}	91.54	[ ]^{a,c}
Test	P_m	n/a	n/a	n/a	[ ]^{a,c}	41.58	[ ]^{a,c}
	P_L	[ ]^{a,c}	63.2	[ ]^{a,c}	[ ]^{a,c}	63.18	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	63.2	[ ]^{a,c}	[ ]^{a,c}	59.40	[ ]^{a,c}
	$P_L + P_b + Q$	[ ]^{a,c}	93.6	[ ]^{a,c}	n/a	n/a	n/a

Note:

1. This is the maximum fatigue usage factor away from the drain hole. The drain hole is qualified for fatigue by testing.

Table 3
Calculated Stresses and CUFs for Primary Nozzle – Safe End & Primary Manway

Loading Condition	Stress Category	Primary Nozzle – Safe End			Primary Manway[1]		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	[ ]^{a,c}	16.00	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	40.05	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	22.17	[ ]^{a,c}	[ ]^{a,c}	45.00	[ ]^{a,c}
Normal and Upset	P_m	[ ]^{a,c}	17.60	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	24.39	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b + Q$	[ ]^{a,c}	48.00	[ ]^{a,c}	[ ]^{a,c}	80.1	[ ]^{a,c}
	Fatigue Usage	[ ]^{a,c}	1.000	[ ]^{a,c}	n/a [2]	1.00	n/a [2]
Faulted	P_m	[ ]^{a,c}	38.40	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	84.00	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	53.21	[ ]^{a,c}	[ ]^{a,c}	94.50	[ ]^{a,c}
Test	P_m	[ ]^{a,c}	21.78	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	[ ]^{a,c}	63.18	[ ]^{a,c}
	$P_L + P_b$	[ ]^{a,c}	30.18	[ ]^{a,c}	[ ]^{a,c}	87.75	[ ]^{a,c}

Notes:

1. Stresses listed as P_L stresses are stresses in the channel head shell. Stresses listed as $P_L + P_b$ stresses are stresses in the cover.
2. The drain hole is qualified for fatigue by testing. Fatigue usage factors away from the drain hole are less than fatigue usage factors for the primary nozzle.

Table 4
Calculated Stresses and CUFs for
Primary Manway Stud & Secondary Shell – Limiting Stress Ratios

Loading Condition	Stress Category	Primary Manway Stud			Secondary Shell – Limiting Stress Ratios		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	[ ]$^{a,c\ (1)}$	35.06$^{(2)}$	[ ]^{a,c}	[ ]^{a,c}	26.70	[ ]$^{a,c\ (4)}$
	P_L	n/a	n/a	n/a	[ ]^{a,c}	40.05	[ ]$^{a,c\ (5)}$
	$P_L + P_b$	n/a	n/a	n/a	[ ]^{a,c}	40.05	[ ]$^{a,c\ (5)}$
Normal and Upset	P_m	[ ]^{a,c}	55.2	[ ]^{a,c}	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	74.5	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b + Q$	n/a	n/a	n/a	[ ]^{a,c}	80.1	[ ]$^{a,c\ (6)}$
	Fatigue Usage	n/a $^{(3)}$	1.00	n/a $^{(3)}$	]^{a,c}	1.00	[ ]$^{a,c\ (5)}$
Faulted	P_m	[ ]^{a,c}	69.0	[ ]^{a,c}	[ ]^{a,c}	56.00	[ ]$^{a,c\ (4)}$
	P_L	n/a	n/a	n/a	[ ]^{a,c}	84.00	[ ]$^{a,c\ (5)}$
	$P_L + P_b$	[ ]^{a,c}	98.6	[ ]^{a,c}	[ ]^{a,c}	84.00	[ ]$^{a,c\ (5)}$
Test	P_m	[ ]^{a,c}	55.2	[ ]^{a,c}	[ ]^{a,c}	39.74	[ ]$^{a,c\ (4)}$
	P_L	n/a	n/a	n/a	[ ]^{a,c}	59.50	[ ]$^{a,c\ (5)}$
	$P_L + P_b$	[ ]^{a,c}	74.5	[ ]^{a,c}	[ ]^{a,c}	59.50	[ ]$^{a,c\ (5)}$

Notes:

1. Required total stud area in square inches.
2. Actual total stud area in square inches.
3. The primary manway stud is qualified for fatigue by testing.
4. Stress on lower secondary shell
5. Stress at junction of lower secondary shell and transition cone.
6. Stress at junction of transition cone and upper secondary shell

Table 5
Calculated Stresses and CUFs for
Steam Outlet Nozzle & Steam Outlet Nozzle – Safe End

Loading Condition	Stress Category	Steam Outlet Nozzle			Steam Outlet Nozzle – Safe End		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	[ ]a,c	26.70	[ ]a,c	[ ]a,c	16.50	[ ]a,c
	P_L	[ ]a,c	40.10	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	[ ]a,c	40.10	[ ]a,c	[ ]a,c	21.90	[ ]a,c
Normal and Upset	P_m	[ ]a,c	29.40	[ ]a,c	[ ]a,c	18.20	[ ]a,c
	P_L	[ ]a,c	44.10	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	[ ]a,c	44.10	[ ]a,c	[ ]a,c	24.10	[ ]a,c
	$P_L + P_b + Q$	[ ]a,c	80.10	[ ]a,c	[ ]a,c	49.50	[ ]a,c
	Fatigue Usage	[ ]a,c	1.00	[ ]a,c	n/a (1)	1.000	n/a (1)
Faulted	P_m	[ ]a,c	56.0	[ ]a,c	[ ]a,c	39.6	[ ]a,c
	P_L	[ ]a,c	84.0	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	[ ]a,c	74.3	[ ]a,c	[ ]a,c	52.5	[ ]a,c
Test	P_m	[ ]a,c	42.1	[ ]a,c	[ ]a,c	21.8	[ ]a,c
	P_L	[ ]a,c	63.2	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	[ ]a,c	63.2	[ ]a,c	[ ]a,c	28.9	[ ]a,c

Note:

1. *Fatigue usage is less than for Steam Outlet Nozzle.*

Table 6
Calculated Stresses and CUFs for
Feedwater Nozzle & Feedwater Nozzle Thermal Sleeve and Feedwater Distribution Ring

		Feedwater Nozzle			Feedwater Nozzle Thermal Sleeve and Feedwater Distribution Ring		
Loading Condition	**Stress Category**	**Stress (ksi)**	**Allow (ksi)**	**Ratio**	**Stress (ksi)**	**Allow (ksi)**	**Ratio**
Design	P_m	[ ]^{a,c}	30.00	[ ]^{a,c}	[ ]^{a,c}	23.30	[ ]^{a,c}
	P_L	[ ]^{a,c}	45.00	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	42.27	[ ]^{a,c}	[ ]^{a,c}	30.52	[ ]^{a,c}
Normal and Upset	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b + Q$	[ ]^{a,c}	90.00	[ ]^{a,c}	[ ]^{a,c}	69.90	[ ]^{a,c}
	Fatigue Usage	[ ]^{a,c}	1.000	[ ]^{a,c}	[ ]^{a,c}	1.000	[ ]^{a,c}
Faulted	P_m	[ ]^{a,c}	63.00	[ ]^{a,c}	[ ]^{a,c}	55.92	[ ]^{a,c}
	P_L	[ ]^{a,c}	94.50	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	85.05	[ ]^{a,c}	[ ]^{a,c}	73.26	[ ]^{a,c}
Test	P_m	[ ]^{a,c}	54.95	[ ]^{a,c}	[ ]^{a,c}	27.63	[ ]^{a,c}
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	82.42	[ ]^{a,c}	[ ]^{a,c}	41.45	[ ]^{a,c}

Table 7
Calculated Stresses and CUFs for
Secondary Manway & Secondary Manway Stud

Loading Condition	Stress Category	Secondary Manway(1)			Secondary Manway Stud		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	n/a	n/a	n/a	[ ]^{a,c} (2)	17.52(3)	[ ]^{a,c}
	P_L	[ ]^{a,c}	45.00	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	45.00	[ ]^{a,c}	n/a	n/a	n/a
Normal and Upset	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	[ ]^{a,c}	49.50	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	49.50	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b + Q$	[ ]^{a,c}	90.00	[ ]^{a,c}	[ ]^{a,c}	97.13	[ ]^{a,c}
	Fatigue Usage	[ ]^{a,c}	1.000	[ ]^{a,c}	[ ]^{a,c}	1.00	[ ]^{a,c}
Faulted	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	[ ]^{a,c}	94.50	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	94.50	[ ]^{a,c}	n/a	n/a	n/a
Test	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	[ ]^{a,c}	64.80	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	89.64	[ ]^{a,c}	n/a	n/a	n/a

Note:

1. Stresses listed as P_L stresses are stresses in the secondary shell at the manway opening. Stresses listed as $P_L + P_b$ stresses are stresses in the cover.
2. Required total stud area in square inches.
3. Actual total stud area in square inches.

Table 8
Calculated Stresses and CUFs for Tube at Tubesheet & Tube in U-bend

Loading Condition	Stress Category	Tube at Tubesheet Stress (ksi)	Tube at Tubesheet Allow (ksi)	Tube at Tubesheet Ratio	Tube in U-bend Stress (ksi)	Tube in U-bend Allow (ksi)	Tube in U-bend Ratio
Design	P_m	[ ]a,c	26.60	[ ]a,c	[ ]a,c	26.60	[ ]a,c
	P_L	n/a	n/a	n/a	[ ]a,c	39.90	[ ]a,c
	$P_L + P_b$	[ ]a,c	35.8	[ ]a,c	[ ]a,c	35.80	[ ]a,c
Normal and Upset	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b + Q$	[ ]a,c	79.8	[ ]a,c	[ ]a,c	79.8	[ ]a,c
	Fatigue Usage	[ ]a,c	1.000	[ ]a,c	[ ]a,c	1.000	[ ]a,c
Faulted	P_m	[ ]a,c	56.00	[ ]a,c	[ ]a,c	56.00	[ ]a,c
	P_L	n/a	n/a	n/a	[ ]a,c	84.00	[ ]a,c
	$P_L + P_b$	[ ]a,c	75.4	[ ]a,c	[ ]a,c	75.40	[ ]a,c
Test	P_m	[ ]a,c	34.00	[ ]a,c	[ ]a,c	34.00	[ ]a,c
	P_L	n/a	n/a	n/a	[ ]a,c	51.00	[ ]a,c
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a

Table 9
Calculated Stresses and CUFs for
Tube to Tubesheet Weld & Primary Chamber Divider Plate

		Tube to Tubesheet Weld			Primary Chamber Divider Plate		
Loading Condition	**Stress Category**	**Stress (ksi)**	**Allow (ksi)**	**Ratio**	**Stress (ksi)**	**Allow (ksi)**	**Ratio**
Design	P_m	[ ]a,c	25.80	[ ]a,c	n/a	n/a	n/a
	P_L	[ ]a,c	38.70	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	[ ]a,c	34.95	[ ]a,c
Normal and Upset	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	[ ]a,c	38.45	[ ]a,c
	$P_L + P_b + Q$	[ ]a,c (1)	77.40	[ ]a,c (1)	[ ]a,c	69.90	[ ]a,c
	Fatigue Usage	[ ]a,c	1.000	[ ]a,c	[ ]a,c	1.000	[ ]a,c
Faulted	P_m	[ ]a,c	35.20	[ ]a,c	[ ]a,c	55.92	[ ]a,c
	P_L	[ ]a,c	52.80	[ ]a,c	[ ]a,c	83.88	[ ]a,c
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a
Test	P_m	[ ]a,c	35.30	[ ]a,c	n/a	n/a	n/a
	P_L	[ ]a,c	52.90	[ ]a,c	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	[ ]a,c	37.40	[ ]a,c

Note:

1. P_L+P_b+Q stress intensity range exceeds the allowable limit of $3S_m$ at this location. The ASME Code Section III Subsection NB allows exceeding the limit of $3S_m$ provided the elastic-plastic analysis is performed per Paragraph NB-3228.5. An analysis more conservative than the requirements of NB-3228.5 was performed.

Table 10
Calculated Stresses and CUFs for
Handhole and Inspection Port in Secondary Shell & Handhole and Inspection Port Bolt

Loading Condition	Stress Category	Handhole and Inspection Port in Secondary Shell[1]			Handhole and Inspection Port Bolt		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	[ ]^{a,c}	26.7	[ ]^{a,c}	[ ]^{a,c} [2]	4.48[3]	[ ]^{a,c}
	P_L	[ ]^{a,c}	40.0	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	45.0	[ ]^{a,c}	n/a	n/a	n/a
Normal and Upset	P_m	[ ]^{a,c}	29.4	[ ]^{a,c}	[ ]^{a,c}	56.8	[ ]^{a,c}
	P_L	[ ]^{a,c}	44.1	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	49.5	[ ]^{a,c}	[ ]^{a,c}	85.2	[ ]^{a,c}
	$P_L + P_b + Q$	[ ]^{a,c}	80.1	[ ]^{a,c}	n/a	n/a	n/a
	Fatigue Usage	[ ]^{a,c}	1.000	[ ]^{a,c}	[ ]^{a,c}	1.000	[ ]^{a,c}
Faulted	P_m	[ ]^{a,c}	56.0	[ ]^{a,c}	[ ]^{a,c}	71.0	[ ]^{a,c}
	P_L	[ ]^{a,c}	84.0	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	94.5	[ ]^{a,c}	[ ]^{a,c}	101.4	[ ]^{a,c}
Test	P_m	[ ]^{a,c}	43.2	[ ]^{a,c}	[ ]^{a,c}	58.0	[ ]^{a,c}
	P_L	[ ]^{a,c}	64.8	[ ]^{a,c}	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	89.6	[ ]^{a,c}	[ ]^{a,c}	87.0	[ ]^{a,c}

Notes:

1. Stresses listed as P_m or P_L stresses are stresses in the secondary shell at the handhole or inspection port opening. Stresses listed as $P_L + P_b$ stresses are stresses in the cover.
2. Required total bolt area in square inches.
3. Actual total bolt area in square inches.

Table 11
Calculated Stresses and CUFs for
Primary Moisture Separator Assembly & Secondary Moisture Separator Assembly

Loading Condition	Stress Category	Primary Moisture Separator Assembly(1)			Secondary Moisture Separator Assembly(1)		
		Stress (ksi)	Allow (ksi)	Ratio	Stress (ksi)	Allow (ksi)	Ratio
Design	P_m	[ ]^{a,c}	24.7	[ ]^{a,c} (2)	[ ]^{a,c}	10.3	[ ]^{a,c} (6)
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	18.7	[ ]^{a,c}	[ ]^{a,c} (6)	15.4	[ ]^{a,c} (6)
Normal and Upset	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b + Q$	[ ]^{a,c}	56.1	[ ]^{a,c} (3)	[ ]^{a,c}	56.1	[ ]^{a,c} (7)
	Fatigue Usage	[ ]^{a,c}	1.000	[ ]^{a,c} (4)	[ ]^{a,c}	1.000	[ ]^{a,c} (7)
Faulted	P_m	[ ]^{a,c}	27.0	[ ]^{a,c} (5)	[ ]^{a,c}	27.0	[ ]^{a,c} (8)
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	[ ]^{a,c}	40.4	[ ]^{a,c} (5)	[ ]^{a,c}	40.0	[ ]^{a,c} (8)
Test	P_m	n/a	n/a	n/a	n/a	n/a	n/a
	P_L	n/a	n/a	n/a	n/a	n/a	n/a
	$P_L + P_b$	n/a	n/a	n/a	n/a	n/a	n/a

Notes:

1. Both the primary moisture separator assembly and the secondary moisture separator assembly are geometrically complex and have many parts. This table only lists the parts with the limiting stress ratios. The notes list the location of the limiting stress ratio.
2. Lower deck plate jacking stud.
3. Intermediate deck plate.
4. Weld of primary separator riser to lower deck plate.
5. Weld of lower deck plate assembly to wrapper.
6. Weld of bottom channel to end channel.
7. Weld of shear panel to end channel.
8. Weld of top channel to upper deck plate.

Table 12
Calculated Stress and CUF Ratios for
Lower Internals (Tube Support System)

Lower Internals (Tube Support System) Location	Ratio of Maximum Stress to Allowable Stress					
	Design		Normal plus Upset		Faulted	
	P_m or P_L	$P_L + P_b$	$P_L + P_b + Q$	Fatigue Usage	P_m or P_L	$P_L + P_b$
Tube Support Plate – In Plane Loading	[ ]^{a,c}	n/a	n/a	n/a	[ ]^{a,c}	n/a
Tube Support Plate – Out of Plane Loading	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Stayrod	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Threads	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Shell Shear Lugs	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
Bearing	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Wrapper Position Block	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
Bearing	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Weld	n/a	n/a	n/a	n/a	[ ]^{a,c}	[ ]^{a,c}
Jacking Studs Thread Shear	[ ]^{a,c}	n/a	n/a	n/a	[ ]^{a,c}	n/a
Jacking Studs Bearing	[ ]^{a,c}	n/a	n/a	n/a	[ ]^{a,c}	n/a
Anti Rotation Key	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
Bearing	n/a	n/a	n/a	n/a	[ ]^{a,c}	n/a
Anti Rotation Key Block Weld	[ ]^{a,c}	n/a	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	n/a

Table 13
Flow Induced Vibration Evaluation
Summary of Calculated Results for Design Conditions

Location	Maximum Fluid-elastic Stability Ratio, FSR(1)	Frequency at Maximum FSR (Hz)	Maximum Turbulence Vibration Amplitude(2,3) (10^{-3} in)	Maximum Tube Bending Stress(2) (psi)	Maximum Tube Wear Depth at 40-year Objective(4) (10^{-3} in)
Straight-Leg Region					
Peripheral Tubes Subjected to High Cross-Flow Inlet Turbulence	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Tube Lane with Maximum Tube Lane Block Effect Subject to High Cross-Flow Turbulence	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Edge of FDB Cutout with Maximum Cross Flow at Tubes without FDB Support	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Inside FDB Cutout at Tubes with Maximum Cross Flow without Assured Support at TSP1	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
U-Bend Region					
Largest Radius Tubes with 3 Sets of AVB's and Longest Tube Spans (Row 25-47)	[ ]a,c **	[ ]a,c **	[ ]a,c	[ ]a,c	[ ]a,c
Intermediate Radius Tubes with 2 Sets of AVB's (Rows 14-24)	[ ]a,c **	[ ]a,c **	[ ]a,c	[ ]a,c	[ ]a,c
Small Radius Tubes with 1 Set of AVB's (Rows 8-13)	[ ]a,c **	[ ]a,c **	[ ]a,c	[ ]a,c	[ ]a,c
Smallest Radius Tubes without AVB Support (Rows 1-7)	[ ]a,c **	[ ]a,c **	[ ]a,c	[ ]a,c	[ ]a,c

Notes:

1. Based on design values for threshold instability constant of [ ]a,c in straight-leg and [ ]a,c in U-bend with damping at two percent of critical for each with all supports active.
2. Square root of the sum of squares of root mean square amplitudes for first 20 normal modes. Estimated peak stress in parentheses.
3. Based on higher turbulence force spectra with C_1 = [ ]a,c for tubes around bundle periphery and along tube lane, than for interior tubes with C_1 = [ ]a,c. S = 2.34 for each.
4. Numbers in parenthesis are provided where there is no potential for fluid-elastic rattling within fabrication clearances. They are based on turbulence-induced displacement calculations at potential wear sites and do not represent detailed wear calculations. Actual results are expected to be negligible. More refined calculations of turbulence wear potential is not merited based on more than 19 years of operating experience with no identifiable indications of tube wear at straight-leg supports. Potential for wear from fluid-elastic rattling within fabrication clearance is based on tube/AVB gaps of [ ]a,c inches adjacent to [ ]a,c inches taken from the overall fit-up distribution measured during fabrication of the limiting Model 54F steam generator. Beaver Valley results are enveloped by this assumption.

** From limiting analysis for Beaver Valley Unit 1. Remaining calculations scaled using factors and reference analyses.

Question 3.

In the first paragraph of its response to Question No. N9 in Enclosure 1 to its letter dated May 26, 2005, FENOC states that the worst-case scenarios that determine maximum differential pressure across each motor-operated valve (MOV) are unaffected by the EPU. In the second paragraph of that response, FENOC states that the EPU requires a change to the high head safety injection (HHSI) pump and that this change potentially increases the differential pressure across various valves. Discuss these two responses.

Response:

The intent of the first paragraph was to note that the design-basis event (e. g. LOCA) that forms the differential pressure basis for a given motor-operated valve (MOV) remains unchanged. The intent of the second paragraph was to note that the Unit 1 and Unit 2 replacement of the charging pump rotating assemblies can affect operating conditions for associated MOVs. As part of the EPU Project, the higher operating pressures associated with the replacement charging pumps have been accounted for in applicable MOV calculations.

Question 4.

In Item B of its response to Question No. N10, FENOC refers to its application of the ComEd pressure-locking thrust prediction methodology for MOVs-1SI-869A/B. Discuss the application of this method.

Response:

The subject MOVs-1SI-869A/B are Velan 3" 1500# Motor Operated Flexible Wedge Gate Valves. The ComEd pressure locking methodology is used for the subject valves, and is also valid for all flexible wedge gate valves.

During an industry effort to address the concerns of NRC Generic Letter 95-07, an analytical method to predict the increase in unseating thrust under a pressure locking scenario for Motor Operated Flexible Wedge Type Gate Valves was developed by Commonwealth Edison Company (ComEd). The Westinghouse Owner's Group created a MATHCAD program Preslok MUHP-6050 and accompanying user's manual to allow the uniform use of the Commonwealth Edison Company pressure locking analysis methodology throughout the industry.

The ComEd pressure locking methodology for calculating the thrust required to open the MOVs under pressure locking scenario utilized Roark' s Engineering Handbook equations (Roark, Raymond J., and Young, Warren C., Formulas for Stress and Strain, 5th Edition, McGraw-Hill Book Company, 1975) and MOV test data to evaluate acceptability of its methodology. The methodology determines the total force required to open the valve under a pressure-locking scenario by solving for the four components to this force. The four components of the force are the pressure locking component, the static unseating component, the piston effect component, and the "reverse piston effect".

In 1999, the above ComEd methodology was used in a BVPS engineering assessment for similar Velan 3" 1500# Motor Operated Flexible Wedge Type Gate Valves (Pressurizer Power Operated Relief Valve [PORV] Block Valves) in response to a second RAI (Request for Additional Information) from the NRC on Generic Letter GL 95-07. Subsequently, the NRC issued a letter to BVPS (dated November 3, 1999), which included an enclosed Safety Evaluation. The Safety Evaluation by the NRC agreed with the BVPS engineering assessment that the subject valves could open under pressure-locking conditions. The NRC considered the use of the ComEd methodology as an acceptable long-term corrective action provided that the appropriate margins, diagnostic equipment accuracy requirements, and methodology limitations are incorporated into the pressure-locking calculations.

FENOC has demonstrated through analysis that the subject valves could open under pressure-locking conditions for a transfer to simultaneous cold leg and hot leg recirculation. The following margins, along with diagnostic equipment accuracy requirements and methodology limitations defined in a letter from ComEd to the NRC dated May 29, 1998 are considered in the calculation.

- The ComEd criteria for a stiff body assembly is greater than 600# and forged body. The subject valves MOVs-1SI-869A/B are Velan 3" 1500# Motor Operated Flexible Wedge Type Gate Valves. The stiff valve body assembly verses flexible body assembly was determined. A stiff body assembly is used in the BVPS analysis based on the valve's pressure rating of 1500# and forged body.
- The ComEd methodology requires a 20% margin between actuator capability and the unseating load under a pressure-locking scenario for a stiff body assembly. This 20% ComEd margin is intended to address uncertainty in the model, random variations in static unseating load, and measurement uncertainty in determining static unseating load. The BVPS calculation results have demonstrated actuator capability exceeds the unseating thrust under a pressure locking scenario by more than 40%.
- A conservative stem friction factor is used in the BVPS analysis.
- A conservative seat to disk friction factor value is used in the BVPS analysis.
- The bonnet pressure does not exceed the pressure/temperature rating of the valve design.
- The pressure conditions for the Inlet, Outlet and Bonnet used in the BVPS analysis maximized the pressure locking force.

The following additional conservatism is used in the BVPS analysis:

- A conservative static unseating load is used in the analysis.
- A conservative packing load is used in the analysis.

The subject MOVs (MOVs-1SI-869A/B) are currently required to be opened to redirect HHSI to the RCS hot legs to support transfer to hot leg recirculation. While conducting a system review of the hot leg switchover requirements associated with the reduced EPU time to transfer, a single failure vulnerability was identified for BVPS-1. This single failure would prohibit obtaining the EPU required flow for hot leg recirculation. In order to achieve the required hot leg flow, FENOC has elected to credit an available alternate flow path to provide hot leg recirculation. This alternate path will use the Low Head Safety Injection (LHSI) flow path to the RCS hot legs. The alternate path will provide the required flow and meets single failure requirements. The flow path will utilize existing LHSI MOVs and these MOVs will be added to the BVPS Generic Letter 89-10/96-05 MOV Program. The LHSI MOVs required are listed below including applicability of pressure locking thermal binding (PLTB).

MOV	Safety Function	PLTB Applicability
1SI-864A/B	Normally open and remain open for cold leg recirculation, closed on transfer to hot leg recirculation	No, normally open and remote manually closed upon transfer to hot legs
1SI-890C	Normally open and remain open for cold leg recirculation, closed on transfer to hot leg recirculation	No, normally open and remote manually closed upon transfer to hot legs
1SI-890A/B	Normally closed and remain closed for cold leg recirculation, opened on transfer to hot leg recirculation	Yes, normally closed and remote manually opened upon transfer to hot legs. Pressure locking potential due to RCS backleakage. Valve bonnet is vented to the upstream side via a bypass line (low pressure side) to prevent pressure locking. These MOVs have parallel disks and thermal binding does not apply for parallel disk design

Question 5.

In the first bullet of Item C of its response to Question No. N10, FENOC states that the safety injection (SI) system valves were modified to eliminate the potential for "PLTB" by drilling a hole in one disc of each valve. Discuss how this modification eliminates the potential for thermal binding.

Response:

The statement "One disc of each valve was drilled to eliminate the possibility of PLTB" in the first bullet of Item C in response to Question N.10 needs to be clarified. The statement should read: "One disc of each valve was drilled to eliminate the possibility of hydraulic and thermally induced pressure locking (PL)." Drilling the disc allows the pressure between the discs and bonnet to relieve. The following discussion explains why the subject valves (2SIS-MOV863A/B, 2SIS-MOV8811A/B, and 2SISMOV-8890A/B) are not susceptible to wedge-effect thermal and stem-effect binding (TB):

During the Generic Letter 95-07 screening at BVPS, the subject valves were determined to be not susceptible to wedge-effect and stem-effect thermal binding based on the following:

- The valves are not required to open following a scenario in which the valves are closed during hot system conditions followed by a cooldown of >100°F.
- The valves are not required to open following a scenario in which they have been closed during hot system conditions while the system/valve is cooling down >100°F (i.e., subject valve terminates system cooling), and the valves have subsequently cooled down.
- The valves are not required to open in a scenario where a temperature gradient of >100°F develops across the valves after they are closed.
- The valve actuator has a compensating spring for stem growth

Question 6.

In Item 2 of its response to Question No. N11 on air-operated valves (AOVs), FENOC states that the feedwater regulating valves (FWRVs) FCV-1FW-478, 488, and 498, and 2FWS-FCV-478, 488, and 498 have increased flow requirements under EPU conditions. FENOC states that the Unit 1 FWRVs were modified and the Unit 2 FWRVs are being replaced. Discuss the qualification of these valves to perform their safety functions.

Response:

The Feedwater Regulating Valves (FWRVs) will have their valve trims modified to increase the valve flow coefficient (Cv) to accommodate the higher EPU flow rates and provide additional control margin for steam generator level control at the EPU conditions. The EPU analyses are based on the increased Cv and the analyses bounds the operation at the existing power level with the existing trim. The BVPS-1 FWRVs will have new trims installed into the existing valves. The installation is scheduled in the upcoming 1R17 refueling outage prior to the EPU implementation. The FWRVs at BVPS-2 are in the process of being replaced. One of the BVPS-2 FWRVs has been replaced with a new valve and the remaining two FWRVs will be replaced in support of the phased approach for power ascension of the EPU. These modifications have been identified as regulatory commitments in FENOC letter L-04-125.

The FWRVs qualification is as follows:

<u>BVPS-1 FCV-1FW-478, -488, -498 QUALIFICATIONS:</u>

1. The BVPS-1 valves are ANSI B31.1, non-seismic, and Non-EQ components. The existing valves are being used with only the trims being modified.

2. Replacement trims are purchased and qualified in accordance with the procurement specification. This specification includes the revised trim requirements based on the revised Cv and EPU operating conditions.

3. The new valve flow coefficient (Cv) was determined by the EPU hydraulic analysis. The valve trim is sized such that the FWRV position at the full uprated power will be less than 80% open providing adequate control range at the uprated power level. The maximum Cv at full open is limited to 1050 to limit maximum feedwater flow to that used in the safety analyses.

4. The BVPS-1 Licensing Requirements Manual requires feedwater isolation in 10 seconds or less. The EPU analysis or the trim modification does not impact the required closure time. The FWRV closure time is tested per 1OST-1.10 Cold Shutdown Valve Exercise Test, to be performed during 1R17 following installation of the revised trim.

5. The Engineering change package will perform functional testing to demonstrate the FWRV operation and final operating position verified following uprate.

BVPS-2 2FWS-FCV478, -488, -498 QUALIFICATIONS:

1. The BVPS-2 FWRVs are ASME Section III Class 3 components.

2. The valves are purchased in accordance with a new procurement specification. This specification endorsed design requirements from the original Westinghouse specifications.

3. The valves are seismically qualified by analysis to the specification requirements. The analysis used seismic accelerations from the design specification "faulted" conditions, i.e. the larger acceleration values.

4. The ASME design compliance is provided by the vendors Valve Design Report in compliance with the ASME Code and design specification.

5. Valve weight and associated forces due to increased uprate flow are evaluated for pipe stress.

6. The new valve flow coefficient of 1050 was determined by EPU hydraulic analysis. The valve trim is sized such that the FWRV position at the full uprated power will be less than 80% open providing adequate control range at the uprated power level. The maximum Cv at full open is limited to 1050 to limit maximum feedwater flow to that used in the safety analyses.

7. Limit switch changes with the new valves are captured in revised Environmental Qualification documentation packages.

8. The BVPS-2 Licensing Requirements Manual requires feedwater isolation in 7 seconds or less. To support this, the FW control valves have the requirement to close in 5 seconds or less. Closure is tested per 2OST-1.10 Cold Shutdown Valve Exercise Test; as was performed during 2R10 and 2R11 refueling outages.

9. The complete valve was hydro, leak and functional tested at the vendor's shop. The installation had radiography on the new butt welds.

Question 7.

In the first bullet in its response to Question No. N12 on the Inservice Testing (IST) Program, FENOC states that new fast-acting Feedwater Isolation Valves HYV-1FW- 100A, B, and C have been installed. Discuss the qualification of the capability of these valves to perform their safety functions.

Response:

The Feedwater Isolation Valves HYV-1FW-100A, B, and C are included in the BVPS-1 Equipment Qualification (EQ) Program. These valves are included in a final BVPS-1 EQ Package. The package documents that these valves have adequately demonstrated their capability to perform their safety function. The package includes documentation that demonstrates that the parent A-290 Test Actuator performs the required safety related function properly throughout its entire aging process and during all postulated Design Basis Events (DBEs). In addition, the parent actuator successfully completed functional tests to verify correct operation and reliability. The vendor test reports justify the BVPS candidate valve by a comparison analysis of the parent valve to the BVPS candidate valve. The results show that the BVPS Feedwater Isolation Valves are qualified to perform their intended safety related function. The actuator seismic qualification addressed both the Operational Basis Earthquake and the Design Basis Earthquake. The tests consisted of bi-axial random multi-frequency tests with superimposed sine beats. The basis of the Required Response Spectra (RRS) curves for the testing was obtained from the specification. Installed orientation was evaluated to be acceptable based upon testing/analysis performed. The valve stroke time was demonstrated both in the shop and field. The functional test data from the shop tests for each valve shows that the valves close with load within the specified closing time. The modification tests in the field for each valve indicates that the valves close within the specified closing time.

Question 8.

In the fourth bullet in its response to Question No. N12, FENOC states that the tolerance settings for the main steam safety valves (MSSVs) and pressurizer safety valves were increased for the EPU. FENOC states MSSVs with the lowest setting pressure will be limited to a lift-setting tolerance of +1/-3%. The lift-setting tolerance for the remaining MSSVs will be limited to a lift-setting tolerance of ±3%, which is a change from the current lift-setting tolerance of +1/-3%. The upper tolerance for the pressurizer code safety valves will be changed from +1% to +3% for BVPS-1, and from +1% to +1.6% for BVPS-2. The current lift-setting tolerance for the pressurizer code safety valves for both units is +1%/-3%. The lower tolerance for the pressurizer code safety valves for both units is unchanged at -3%. Discuss the impact of these changes on safety margins.

Response:

In addition to supporting the increase in rated thermal power for BVPS-1 and BVPS-2, the Extended Power Uprate (EPU) project included the objective of optimizing the allocation of margins between plant operation and safety analyses. The analysis input parameters for the safety analyses were selected to accomplish this objective. One area that was identified for an increase in plant operating margin was the area of safety valve lift-setting tolerance. For BVPS-1 and BVPS-2 at current power conditions, the lift-setting tolerance for both the main steam safety valves (MSSVs) and the pressurizer safety valves (PSVs) is +1/-3%. For both BVPS-1 and BVPS-2 at EPU conditions, the MSSV and PSV lift-setting tolerance was initially selected as +/-3%, subject to obtaining acceptable safety analysis results.

The safety analysis impact of increasing the MSSV and the PSV positive lift-setting tolerance from +1% to a higher number is to reduce the safety analysis margin relative to the safety analysis acceptance criteria. However, the limiting safety analyses continue to show acceptable analysis results and analysis margins relative to the analysis acceptance criteria. Although increasing the safety valve positive lift-setting tolerance may tend to reduce analysis margins, the analysis acceptance criteria are not impacted and the associated safety margins (i.e., the margin between the safety analysis acceptance criteria and the associated design failure point or limitation, as defined in NSAC-125, Guidelines for 10 CFR 50.59 Safety Evaluations, June 1989) are not impacted. Since the changes to MSSV and PSV lift-setting tolerances were included in the safety analyses along with the changes to other analysis input parameters for EPU, the results of the analyses reflect the synergistic effects of all analysis input parameter changes. Thus, the impact of the change to MSSV and PSV positive lift-setting tolerance on analysis margins cannot be separated from the impact of the other changes to analysis input parameters for EPU. The following provides additional information on the selection and justification of the MSSV and PSV lift-setting tolerances for EPU conditions.

For the MSSVs, the limiting non-LOCA safety analysis (i.e., Loss of External Electrical Load and/or Turbine Trip (LOL/TT) event) showed that acceptable analysis results and analysis margins to acceptance criteria could be obtained with lift-setting tolerances of +/-3% for both BVPS-1 and BVPS-2. The limiting LOCA analysis (i.e., Small Break LOCA event) showed that acceptable analysis results and analysis margins to acceptance criteria could be obtained with a lift-setting tolerance of +/-3% for the MSSVs except for the first MSSV (i.e., valve with the lowest setpoint), which needed to retain the current lift-setting tolerance of +1/-3% in order to provide sufficient analysis margin with respect to analysis acceptance criteria for the Small Break LOCA event.

For the PSVs, the limiting non-LOCA analysis (i.e., LOL/TT event) showed that acceptable analysis results and analysis margins to acceptance criteria could be obtained with lift-setting tolerances of +/-3% for BVPS-1 and +1.6/-3% for BVPS-2. Since the PSVs are not actuated for the Small Break LOCA event, the PSV lift-setting tolerance is not used as an input parameter to Small Break LOCA analysis and, therefore, the PSV lift-setting tolerance is not limited by Small Break LOCA analysis.

In summary, the limiting Non-LOCA and LOCA safety analyses support the following safety valve lift-setting tolerances by demonstrating acceptable analysis results, with acceptable analysis margins relative to analysis acceptance criteria:

1. For BVPS-1, lift-setting tolerances of +1/-3% for the first MSSV (i.e., valve with the lowest lift setpoint), +/-3% for the other four MSSVs (i.e., valves with higher lift setpoints), and +/-3% for the PSVs.

2. For BVPS-2, lift-setting tolerances of +1/-3% for the first MSSV (i.e., valve with the lowest lift setpoint), +/-3% for the other four MSSVs (i.e., valves with higher lift setpoints), and +1.6/-3% for the PSVs.

Descriptions of the limiting safety analyses are provided in EPU Licensing Report Section 5.3.6, Loss of External Electrical Load and/or Turbine Trip, and Section 5.2.2, Small Break LOCA.

Question 9.

Is FENOC relying on safety valves at BVPS-1 and 2 to operate with water flow for EPU conditions? If so, discuss the qualification of the valves for this condition.

Response:

The most serious consequence of a spurious safety injection (SI) event is the potential to fill the pressurizer prior to event termination (EPU Licensing Report Section 5.3.18, Spurious Operation of the Safety Injection System at Power). For the situation where the pressurizer power operated relief valves (PORVs) are not available, which is permitted by the Technical Specifications, filling of the pressurizer can result in the potential for water relief through the pressurizer safety valves (PSVs). Safety analyses were performed for BVPS-1 and BVPS-2 for the spurious SI event to determine if the pressurizer will fill prior to event termination. Since pressurizer filling was predicted, PSV relief data (i.e., number of lift cycles, flow rates, and fluid conditions) was developed for the spurious SI event. This data was used in PSV operability assessments to demonstrate that the valves are capable of operating acceptably for the fluid relief conditions defined by the safety analyses for the time period from when PSV fluid relief is initiated until the event is terminated by operator action at 10 minutes after event initiation.

The PSV operability assessments consist of analyses that compare the safety valve fluid relief conditions from the safety analyses to the EPRI safety valve test results for the Target Rock safety valves for BVPS-1 (EPRI NP-2770-LD, Volume 8, Interim Report, March 1983, EPRI/C-E PWR Safety Valve Test Report – Test Results for Target Rock Safety Valve) and for the Crosby safety valves for BVPS-2 (EPRI NP-2770-LD, Volume 9, Interim Report, March 1983, EPRI/C-E PWR Safety Valve Test Report – Test Results for Crosby/Framatome Safety Valve with Assisted Device). The PSV operability assessments use the methodology developed in WCAP-11677 (Pressurizer Safety Valve Relief Valve Operation for Water Discharge During a Feedwater Line Break, January 1988), modified to extend the results of the WCAP to cover water relief during a spurious SI event. The subject WCAP was developed by the Westinghouse Owners Group (WOG) and was designed to be referenced in plant-specific submittals addressing PSV operability for water discharge during a feedwater line break event, pursuant to the requirements of NUREG-0737, Section II.D.1.

The PSV operability assessments include evaluations to show that the valve will operate in a stable manner when subjected to the relief conditions (i.e., flow rates, pressures, and temperatures) and the number of lift cycles calculated in the safety analyses for the spurious SI event for the time period from when PSV fluid relief is initiated until the event is terminated by operator action at 10 minutes after event initiation. Based on these PSV operability assessments, it was concluded that the BVPS-1 and BVPS-2 PSVs will exhibit stable operation, function acceptably for the number of lift cycles, flow rates, and fluid conditions defined by the safety analyses for the spurious SI event, and will reseat properly following termination of the spurious SI event.

Question 10.

In its response to Question No. N13 on monitoring potential adverse flow effects during EPU startup, FENOC provides examples of its Level 2 Acceptance Limits. In the fifth bullet of those examples, the licensee states that visual observations will be made of increased pipe or component vibration. Discuss the adequacy of visual observations in lieu of the use of accelerometers.

Response:

Review of vibration failures and recent power uprate experience indicates that the areas most susceptible to vibration as a result of an Extended Power Uprate (EPU) are areas within the plant secondary systems, primarily in non-safety related piping outside containment. The proposed use of visual observation is considered adequate based on the scope of the planned monitoring program as discussed below.

The planned monitoring program is consistent with ASME OM-S/G-2003, "Standards and Guides for Operation and Maintenance of Nuclear Power Plants," Part 3, Vibration. (Response to question N.7 of FENOC letter L-05-078)

In support of the EPU, FENOC has performed baseline walkdowns to identify areas susceptible to potential vibration in the secondary side systems. The walkdowns were performed several times at various plant operating conditions, the results recorded and target areas for monitoring during power ascension have been identified. The areas targeted for vibration monitoring are located in the secondary side systems (feedwater, main steam, heater drains, extraction steam and condensate) outside containment which are the areas where increased flows will occur during power ascension.

The piping within the target areas are accessible during power ascension and, with the results of the baseline walkdown data, provide a solid foundation for which visual observation can be used to monitor for potential increased vibration conditions during the power ascension. Piping within the target areas that demonstrate a noticeable change in the vibration are measured by mechanical means and/or additional instrumentation (e.g., hand held monitors as required) to obtain the necessary data. Collected data exceeding established limits are then evaluated to determine the impact on the support design. In addition, general area walkdowns are performed during power ascension to identify other areas where abnormal vibration conditions may have developed as a result of system interactions.

The main steam and feedwater piping inside containment is not readily accessible for performing vibration monitoring during power ascension. This piping inside containment is not considered to be a target area for the following reasons:

1. The main steam and feedwater piping is well supported and seismically designed.
2. The piping is large diameter, not overly flexible, with large diameter bends and few elbows.
3. There are no long cantilever branch lines or branch lines with heavy unsupported valves.
4. There is no history of vibration problems in these lines at BVPS.
5. Operating experience from another 3-loop Westinghouse-designed station, which operates at BVPS EPU licensed power levels and which has similar piping and support design, has had no identified history of vibration problems with these lines.
6. Review of operating experience at recent EPU stations has not identified any significant vibration in these systems inside containment which would have a safety or failure concern.

In summary, the use of visual observation for performing vibration monitoring during power ascension is considered reasonable based on the extensive baseline walkdown data collected to date, the identification of targeted areas and its accessibility, and the ability to collect vibration measurements on an as-needed basis.

Question 11.

In its response to Question No. N14, FENOC discusses its consideration of potential flow-induced vibration effects. Has FENOC addressed the capability of any feedwater or condensate sample probes to withstand increased flow under EPU conditions?

Response:

Neither BVPS-1 nor BVPS-2 have sample probes in either the condensate or feedwater systems which extend into the flow streams. Flow measuring devices in these systems include Leading Edge Flow Meters (feedwater only), orifice plates and flow nozzles. None of these devices have probes which extend into the flow stream. Annubar averaging pitot tube type flow elements are not used in these systems.

Themowells do extend into the flow stream and are used throughout the condensate and feedwater systems for temperature measurement. However, the design pipe flow velocity for these thermowells conservatively bounds the calculated EPU pipe flow velocities in these systems.

The following information pertains to the EPU application, as well as the RSG application:

July 8, 2005, Second-Round RAI Questions

Question 1. Overpressure Protection During Power Operation

The BVPS-1 and 2 EPU submittal does not address the analysis requirements of Standard Review Plan (SRP), Section 5.2.2, Section II.A, "Overpressure Protection."

The BVPS-1 EPU submittal, and L-05-112 Enclosure 2 (Response B.1) deals with overpressure protection during power operation, (i.e., safety valve sizing, by analyzing a Chapter 15 event). Chapter 15 event analyses do not address the overpressure protection requirements of the American Society of Mechanical Engineers, *Boiler and Pressure Vessel Code* (ASME Code), Section III, NB-7300 and NC-7300, and they are not consistent with the approach described in WCAP-7769, Rev 1, Overpressure Protection for Westinghouse Pressurized Water Reactors," June 1972.

Please provide analyses, per SRP 5.2.2, II.A, which show the continued adequacy of the BVPS-1 safety valve sizing, and consistency with the BVPS-1 licensing basis-design analysis approach of WCAP-7769, Rev 1, which credits the second safety-grade trip from the reactor protection system.

The same question applies to BVPS-2. Please provide analyses, per SRP 5.2.2, II.A, which show the continued adequacy of the BVPS-2 safety valve sizing, and consistency with the BVPS-2 licensing basis-design analysis approach of WCAP-7769, Rev 1, which credits the second safety-grade trip from the reactor protection system.

Response:

Analyses were performed for BVPS-1 and 2 delaying reactor trip until the second trip signal from the Reactor Protection System (RPS) was generated. This analysis is identical to that discussed in Section 5.3.6 of Enclosure 2 to letter L-04-125 except that the first trip generated by the RPS is not credited. For the analysis of a Loss of Load/Reactor Trip event without pressure control, which is the limiting event for maximum RCS pressure, the second trip generated by the RPS is an overtemperature delta T trip. This occurs approximately 6-10 seconds after the high pressurizer pressure trip setpoint is reached. The timing of the trip has very little impact on the peak primary pressure. The pressurizer safety valves are adequately sized such that the peak pressure occurs just after the pressurizer safety valves open. The pressure transient ends when the safety valves open. The results of this analysis demonstrated that the acceptance criteria of less than 110% of design is met and the pressurizer safety valves are adequately sized for EPU conditions.

Question 2.

If an inadvertent emergency core cooling system (ECCS) actuation event should occur, and the block valves are open, then the power-operated relief valves (PORVs) might open and possibly relieve water. If the PORVs are assumed to reseat properly, after having relieved water, please provide information that details how the circuitry that controls the closing signal will meet Class 1E requirements. This is necessary in order to justify the assumption that the PORVs can be relied upon to close when pressurizer pressure drops below the closing setpoint.

Response:

BVPS-1:

The PORVs can be relied upon to automatically close when pressurizer pressure drops below the closing setpoint because the installed plant equipment used for automatic initiation and closure of each PORV meets Class 1E requirements.

General Description of PORV circuitry:
(Reference BVPS-1 UFSAR Figure 7.2-1 Sheets 6 and 11)

The PORVs can be automatically controlled (modulated) by the pressurizer pressure controller module designated as P-444 or P-445. The control circuits are Class non-1E and are not relied upon for automatic PORV closure during a spurious Safety Injection (SI) actuation event. The PORV Class non-1E control signals are overridden and the PORVs will automatically close when pressurizer pressure reaches the P-11 setpoint. The permissive P-11 is a Class 1E signal initiated by the Solid State Protection System (SSPS) and is a subset of initiation signals comprising the Engineered Safety Features Actuation System (ESFAS) which meets IEEE criteria as set forth in IEEE Std. 279-1971.

Referring to BVPS-1 UFSAR Figure 7.2-1 Sheet 11, the PORV will automatically open provided the control board selector switch is in AUTO, the control circuit directs the PORV to open and the pressurizer pressure is above the P-11 setpoint. If pressurizer pressure is below P-11, the PORV will automatically close.

BVPS-1 UFSAR Figure 7.2-1 Sheet 6 shows how the redundant Class 1E pressurizer pressure protection signals (P-455, P-456, P-457) are logically combined within SSPS and P-11 is initiated. BVPS-1 Technical Specification Table 3.3-3 functional unit 8.b describes the required operating modes for P-11. Table 4.3-2 functional unit 8.b describes the surveillance requirements for P-11.

Additional Information: BVPS-1 UFSAR Section 7.3 provides the ESFAS description and adherence to the applicable General Design Criteria. The BVPS-1 UFSAR Section 7.2 discusses details for analog variables (pressurizer pressure) and adherence to GDC criteria. The electrical systems meet the requirements of IEEE Std. 308-l97l.

The PORV valves and valve operators are safety related and seismically qualified per IEEE-344. The PORV control board mounted control switch (mild environment) is safety related and seismically qualified per IEEE-344. The PORV solenoid valves are safety related, seismically qualified per IEEE-344 and environmentally qualified per IEEE-323.

BVPS-1 UFSAR Figure 7.2-1 Sheet 6 shows the applicable Class 1E 120 VAC Vital Bus power source for each pressurizer pressure instrument channel (designated I for Vital Bus I, II for Vital Bus II, III for Vital Bus III). BVPS-1 UFSAR Section 8 provides a comprehensive explanation of the Class 1E electrical system and applicable codes and standards.

BVPS-2:

The PORVs can be relied upon to automatically close when pressurizer pressure drops below the closing setpoint because the installed plant equipment used for automatic initiation and closure of each PORV meets Class 1E requirements.

General Description of PORV circuitry:
(Reference BVPS-2 UFSAR Figure 7.3-11, 7.3-16, and 7.3-22)

The PORVs can be automatically controlled (modulated) by the pressurizer pressure controller module designated as P-444 or P-445. The control circuits are Class non-1E and are not relied on for automatic PORV closure during a spurious Safety Injection (SI) actuation event. The PORV Class non-1E control signals are overridden and the PORVs will automatically close when pressurizer pressure reaches the Pressurizer Pressure Relief Interlock setpoint. The Pressurizer Pressure Relief Interlock signal is a Class 1E signal initiated by the Solid State Protection System (SSPS) and is a subset of initiation signals comprising the Engineered Safety Features Actuation System (ESFAS) which meets IEEE criteria as set forth in IEEE Std. 279-1971.

Referring to BVPS-2 UFSAR Figure 7.3-22, the PORV will automatically open provided the control board selector switch is in AUTO, the control circuit directs the PORV to open and pressurizer pressure is above the Pressurizer Pressure Relief Interlock setpoint. If pressurizer pressure falls below the Pressurizer Pressure Relief Interlock setpoint, the PORV will automatically close.

BVPS-2 UFSAR Figure 7.3-11 shows how the redundant Class 1E pressurizer pressure protection signals (P-455, P-456, P-457) are logically combined within SSPS and the Pressurizer Pressure Relief Interlock signal is initiated.

Additional Information: BVPS-2 UFSAR Section 7.3 provides the ESFAS description and adherence to the applicable General Design Criteria. The BVPS-2 UFSAR Section 7.3.1.1.2 discusses details for analog variables (pressurizer pressure) and adherence to GDC criteria. The electrical systems meet the requirements of IEEE Std. 308-l97l.

The PORV valves are safety related, seismically qualified per IEEE-344. The PORV valve operators are safety related, seismically qualified per IEEE-344, environmentally qualified per IEEE-323. The control board mounted control switch (mild environment) is safety related and seismically qualified per IEEE-344.

BVPS-2 UFSAR Figure 7.3-11shows the applicable Class 1E 120 VAC Vital Bus power source for each pressurizer pressure instrument channel (designated I for Vital Bus I, II for Vital Bus II, III for Vital Bus III). BVPS-1 UFSAR Section 8 provides a comprehensive explanation of the Class 1E electrical system and applicable codes and standards.

Question 3.

For the analysis case in which the block valves are assumed to be closed (i.e., the case that assumes the PORVs are not credited to mitigate an inadvertent ECCS actuation event), please explain how the pressurizer water temperature is calculated. Specifically, indicate whether the water in the pressurizer is assumed to be uniformly mixed with the insurge water, or stratified (i.e., simply pushed out of the safety valves in a piston fashion). Also please discuss the basis for assuming pressurizer heaters operate when the reactor coolant system (RCS) is pressurizing.

Response:

The LOFTRAN computer code treats the pressurizer as two homogeneous volumes - one steam and one water. The pressurizer water temperature is calculated based on uniform mixing of all water which may ingress to the liquid phase, (e.g., insurge, spray, condensation, etc.). In the time frame of the transient (i.e., 600 seconds), the total pressurizer insurge is approximately 300 ft^3. The initial pressurizer water volume is in excess of 700 ft^3. Thus, if stratification and no mixing were assumed, the colder insurge water would not be released through the safety valves prior to operator action to terminate the event because the initial volume of water in the pressurizer is well in excess of the amount of insurge. Since potential stratification would not lead to colder insurge water being discharged, the water temperature used for the PSV qualification is conservatively low because it is assumed that the colder insurge water is mixed with the remaining water in the pressurizer.

Two cases are run with and without operation of the pressurizer heaters to determine the limiting case in terms of minimum water temperature and the number of lift cycles experienced by the PSVs as stated in assumption 3 of Section 5.3.18 of Enclosure 2 to letter L-04-125. Operation of the pressurizer heaters potentially causes faster filling of the pressurizer due to expansion of the water volume. The case with pressurizer heaters only models operation of the heaters when the pressure control system would demand operation. The proportional heaters are on when the pressurizer pressure is less than 15 psi above the nominal pressure. The backup heaters actuate when the pressurizer water level increases 5% above the initial water level. For an inadvertent ECCS event, proportional heaters are on briefly at the beginning of the transient and the backup heaters actuate when the water level increases and remain on for the remainder of the transient.

Question 4.

Please provide copies of the following documents, all of which are cited in Enclosure 1, Attachment C:

a. **OE8903 (Potential for RCS to be outside the Design Basis during an Inadvertent ECC Actuation at Power) - Diablo Canyon Issue**

b. **CR 980894 (Evaluation of Diablo Canyon pressurizer safety (PSV) valve issue for BVPS)**

c. **NSAL 98-007, 8/11/98 - PSV Evaluations with modified pressurizer heater and spray models**

d. **EM 116856 (Evaluation of NSAL 98-007 for BVPS)**

e. **Letter NPDDBE;0069 - 5/11/98 - R. A. Hruby to K. L. Ostrowski (PSV issue not applicable to BVPS-1).**

f. **Westinghouse calculations CN-TA-98-031 and 032 which provide results of PSV operability studies for inadvertent ECCS and feedline break events (limiting events for pressurizer fill/PSV water relief).**

g. **Westinghouse letter DLC-98-736 (N.S. Kury to W.R. Kline, 6/4/98) which transmitted the Westinghouse calculations and confirmed acceptability of the calculation results**

Response:

The reference documents were assembled and provided for NRC review at the Westinghouse Rockville offices on October 27, 2005.

Question 5.

FENOC's Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.59, Evaluation No. 98-258 (L-05-112 Enclosure 1, Attachment C) applies to BVPS-2. Please provide either a corresponding evaluation for BVPS-1 or an explanation of why such an evaluation is not applicable (i.e., based upon Letter NPDDBE;0069 - 5/11/98).

Response:

The BVPS-2 UFSAR was updated in 1999 as a result of a 10 CFR 50.59 Evaluation (98-258) written in response to an Operational Experience issue regarding water discharge through pressurizer safety relief valves (SRVs) at Diablo Canyon. At the time, as documented in a BVPS Design Engineering assessment (contained in BVPS letter NPDDBE:0069), it was determined that the concern applied to BVPS-2, since it had the same model valves as Diablo Canyon. However, since BVPS-1 had a different model SRV, the concern was not judged to be applicable to BVPS-1. Recently, subsequent review by FENOC engineering staff has determined it would be more appropriate for the BVPS-1 UFSAR to contain a discussion of pressurizer SRV water relief. The relevant BVPS-1 UFSAR update will be incorporated into the next scheduled UFSAR update.

Question 6.

Section 5.3.18 of the license amendment request (LAR) states, "The third criterion is met if it can be demonstrated that the pressurizer does not become water-solid in the minimum allowable operator action time. However, if SI flow is not terminated before the pressurizer becomes water solid, it must be demonstrated that this Condition II event does not lead to a more serious plant condition. In this situation, a pressurizer safety valve (PSV) operability analysis must be performed to demonstrate that the PSVs would continue to function under water relief conditions for the period of time required for the operators to take action to prevent or terminate water relief through the safety valves.

The required operator action is to either terminate SI flow to avert a water-solid condition or to confirm that at least one PORV is unblocked and available for relief. Should water relief through the pressurizer PORVs occur, the PORV block valves would be available to isolate the RCS if a PORV fails to close."

a. **What are the procedures that direct the operator to, "either terminate SI flow to avert a water-solid condition or to confirm that at least one PORV is unblocked and available for relief"? How long would it take the operator, following procedures, to accomplish these actions?**

b. **If the PSVs are qualified for water relief, then why would the operator have to, "either terminate SI flow to avert a water-solid condition or confirm that at least one PORV is unblocked and available for relief"? If the PSVs are qualified for water relief, then it seems the operator would simply be required to terminate charging flow before pressurizer water temperature drops below the temperature shown to be acceptable in the Electric Power Research Institute's (EPRI's) valve tests. Where is the time limit and procedure for that?**

c. **How does the BVPS-1 and 2 application, and subsequent RAI responses, demonstrate that the Inadvertent ECCS Actuation, a Condition II event, does not lead to a more serious Condition III event?**

Response:

6.a The identified spurious safety injection (SI) scenario was conducted on the BVPS-1 simulator with a BVPS-1 Operating Crew during the BVPS-1 Emergency Operating Procedure revision validation process. The crew confirmed that at least one PORV was unblocked and available for relief. The crew then progressed through their procedures and terminated SI flow and established normal charging flow thereby controlling pressurizer level and preventing pressurizer overfill. Both actions were completed within the stated operator action time assumption of 10 minutes from initiation of the event, as stated in Section 5.3.18.2.7 of the EPU LAR.

6.b The procedure for qualifying the PSVs for water relief looks at both the temperature of the water discharge and the expected number of opening and closing cycles under these conditions during a spurious SI event. When it is stated that the PSVs are qualified for water relief, this does not mean they are qualified for an unlimited number of cycles. The analysis determines the expected number of PSV cycles and the water discharge temperature which may occur within the expected operator action time. Operator action within the time assumed in the analysis is confirmed by simulator exercises as part of the EOP validation process.

No analysis credit is given for PORV opening which would also mitigate PSV opening since the block valve could be closed or capable of being closed. The BVPS units typically operate with all block valves open unless PORV leakage requires closure. Although not required by Technical Specifications, maintaining block valves open is considered good practice to manage risk exposure to Automatic Transient Without Scram (ATWS) events.

Analyses were also performed to determine the fluid conditions for a PORV opening. For BVPS-1, which has air-operated PORVs, the maximum number of expected opening and closing cycles was determined to be 12. The BVPS-1 PORVs have a seismically qualified nitrogen backup system which automatically supplies the valves in the event that the air system is unavailable. This system is sized such that it is capable of stroking the valves more than 12 times. The BVPS-2 PORVs are solenoid actuated and do not require air to operate.

6.c Inadvertent ECCS Actuation could lead to a more serious Condition III or higher event if as a result, an unisolable path from the RCS were created. The safety analyses performed for BVPS have shown that it is expected that during an inadvertent ECCS actuation event, either the PORVs or the PSVs will open and following filling of the pressurizer, water will be discharged. Operator actions are credited within 10 minutes following event initiation to terminate SI or confirm that a PORV block valve is open and subsequently terminate SI. Terminating of SI will result in termination of water discharge provided that either the PORV or PSV re-closes following pressure reduction to the closing setpoint.

Based on the water temperature conditions and number of expected cycles for the PSVs within the operator action time, analyses have shown that the valves are capable of re-closing. If the PORVs open during the transient, no PSV opening will occur since the capacity of a PORV exceeds the capacity of the charging pumps. The PORVs are capable of passing water and will automatically re-close on a qualified low pressure signal via a Class 1E control system. Preliminary analyses have shown that the discharge piping for both the PSVs and PORVs is capable of withstanding the potential water discharges with no adverse effects. These analyses will be completed prior to implementation of the license amendments (commitment previously identified in FENOC letter L-05-112 EPU RAI Response dated July 8, 2005, Commitment List - Enclosure 3). Therefore, the inadvertent ECCS actuation event will not result in an unisolable path from the RCS and no Condition III or higher event will be created.

Question 7.

BVPS-1 and 2 current Technical Specification (CTS) 3.9.8.1, "Residual Heat Removal and Coolant Circulation," Action C states, "The residual heat removal loop may be removed from operation for up to 4 hours per 8 hour period during the performance of Ultrasonic In-service Inspection inside the reactor vessel nozzles provided there is at least 23 feet of water above the top of the reactor vessel flange." This residual heat removal (RHR) out of service allowance is four times longer than the standard technical specification (STS) allowance. In order for the NRC staff to continue their review of FENOC's EPU request for BVPS-1 and 2, provide the analysis that demonstrates that the 4-hour RHR out-of-service allowance is acceptable. Include inputs, assumptions, methodologies, and limitations on the analysis. In addition, please identify any and all limitations and restrictions on the use of the 4-hour RHR out-of-service allowance.

Additionally, CTS 3.9.8.1 Action C, BVPS-1 and 2 CTS 3.9.8.1, "Residual Heat Removal and Coolant Circulation," includes Action B which states, "The residual heat removal loop may be removed from operation for up to 1 hour per 8 hour period during the performance of CORE ALTERATIONS in the vicinity of the reactor pressure vessel (hot) legs." In order for the NRC staff to continue their review of FENOC's EPU request for BVPS, provide the following:

a. **Describe the BVPS-1 and 2 controls that prevent the 3.9.8.1 Action B exception that allows the required RHR loop to be removed from operation for ≤ 1 hour per 8-hour period, and the 3.9.8.1 Action C exception that allows the required RHR loop to be removed from operation for ≤ 4 hours per 8-hour period from being invoked during the same 8-hour period and/or consecutively.**

b. **The analysis which shows the RHR requirements continue to be met with the worst case synergistic effects of these exceptions. Include all inputs, assumptions, limitations, and results of that analysis. Identify any controls necessary to ensure the analysis remains bounding.**

Response:

Technical Specification 3.9.8 was amended per Amendment No. 43 dated May 15, 1981, at the request of the NRC. The Technical Specification allows for taking RHR out of service for two distinct conditions. Action statement B allows for a one hour outage of RHR in an eight hour period during fuel movement in the vicinity of the hot legs. Action C allows for a four hour outage of RHR during a eight hour period for ultrasonic in-service inspection of the reactor vessel nozzles provided that there is at least 23 feet of water above the top of the reactor vessel flange. The change also included a requirement in TS 3.9.10 that at least 23 feet of water be maintained over the top of the reactor vessel flange during movement of fuel assemblies. Therefore, both conditions effectively require at least 23 feet of water over the reactor vessel flange. The SER for this amendment stated that:

"We have reviewed the decay heat removal TS proposed by the licensee and the accompanying Safety Evaluation. Based on this review, we have determined that the proposed TS are more conservative than the existing TS with respect to the concerns of the Model TS forwarded by our letter dated June 11, 1980."

While no analysis was performed to directly support the TS change, time to boil analyses are performed prior to and during each outage to assess the available operator action time should RHR be lost or removed from operation under the applicable action statements. These analyses are part of the overall shutdown safety program. This program requires a review of the outage schedule prior to shutdown and is monitored during the outage to manage shutdown safety function availability. If an outage plan were developed which required entry into TS 3.9.8.1 Action C, this would drive the RCS Decay Heat Removal shutdown safety function status to a level orange. It is unlikely that this schedule would be approved based on this status; however, if it was decided to proceed with such a schedule, senior management approval would be required. For a Shutdown Safety Status of Orange, extensive management controls and shutdown safety contingency plans would be put in place for the activity.

During the period in which the refueling cavity is flooded and a minimum of 23 feet of water is available above the reactor vessel flange, the time to boil analysis results show a minimum of approximately 6 hours with all fuel in the reactor vessel at the minimum core offload time of 100 hours following shutdown. These analyses use cycle specific decay heat calculations as input based on the SIMULATE-3 core design models. The RCS and refueling cavity water volumes assumed in the calculations are based on the system conditions for each specified outage sequence. In the case of the calculation with 23 feet of water above the reactor vessel flange, portions of the refueling cavity above the reactor vessel flange are included along with the active core volume and upper plenum. Calculations for this conditions assume that the RCS loops are isolated and therefore the loop volumes, downcomer volume and lower plenum volumes are not credited. Portions of the hot leg volume to the loop isolation valves are credited. The time to boil calculations assume an initial RCS temperature of 95°F. These analyses will be slightly impacted by EPU since the decay heat levels will be approximately 8% higher than the current level.

It should be noted that ultrasonic inspections of the reactor vessel nozzles are normally only performed after the entire core has been offloaded to the spent fuel pool since the core barrel must be removed to access the cold leg nozzles. Full core offload is a normal refueling practice at BVPS. During this period when the fuel is not in the reactor vessel, Technical Specification 3.9.8.1 is not applicable based on the applicability notation that states "with fuel in vessel." Performing inspections with no fuel in the vessel prevents simultaneous or consecutive entry into Actions B and C of the Technical Specification.

Question 8.

The response to Question A.13, dated July 8, 2005, states, "The current spent fuel pool criticality licensing basis for BVPS-1 and 2 does not include a commitment to 10 CFR 50.68." It continues to imply that both BVPS-1 and BVPS-2 are operating under a 10 CFR 70.24 exemption. BVPS-2 takes credit for the presence of soluble boron, which is allowed only under 10 CFR 50.68, as stated in the safety evaluation for Amendment No. 128, dated February 11, 2002 ADAMS Accession No. ML0200203731).

Since the 10 CFR 70.24 exemption was issued prior to the allowance for boron credit, it is no longer valid. It is necessary to commit to 10 CFR 50.68. Please demonstrate that the requirements of 10 CFR 50.68 are satisfied, or document that the 10 CFR 70.24 exemption allows for boron credit.

Response:

To demonstrate that the requirements of 10 CFR 50.68 are satisfied, compliance to the criteria identified in 10 CFR 50.68(b) was evaluated for BVPS-2, and the results are summarized below:

- Fuel assemblies are stored and handled in accordance with site procedures such that that criticality is precluded even if the area where the assembly is being stored or handled is flooded with unborated water.

  Assemblies are stored either in the New Fuel Storage Area or the Spent Fuel Pool. Both of these areas have been explicitly analyzed to show that they remain subcritical even if flooded with unborated water.

  Fuel movement is directed by various site procedures. Beaver Valley Power Station Unit 1/2 Outage Management Manual, Chapter 16 (OMM-16), "Site Receipt and Handling of New Fuel Assemblies and Shipping Containers," controls the receipt of new assemblies onto the site. Per OMM-16, assemblies are removed from the shipping container one at a time and placed into the New Fuel Storage Area. Refueling procedure 1/2RP-3.11, "New Fuel Movement" controls moving the fuel from the New Fuel Storage area into the pool. Per 1/2RP-3.11, assemblies are moved one at a time from the New Fuel Storage area into the pool. Movement of individual assemblies precludes criticality.

- The New Fuel Storage Area maintains K_{eff} less than 0.95, at a 95 percent probability and 95% confidence level, with fuel of maximum reactivity (5.0 weight percent) when flooded with unborated or low-density (optimum moderation) water.

- The K_{eff} of the Spent Fuel Pool racks is less than 0.95, at a 95 percent probability, 95 percent confidence level, with credit for 450 ppm of boron, and less than 1.0 with unborated water.

  The analyses performed to assure the K_{eff} limit of 0.95 is met used the methodology contained in WCAP-14416-NP-A, Rev. 1 as supplemented by the calculations provided in Westinghouse letter FENOC-00-110, dated February 3, 2000. It uses the NITAWL-II and XSDRNPM-S codes for cross-section generation and KENO Va (Petrie and Landers 1993) for reactivity determination.

- The quantity of Special Nuclear Material (SNM) , other than nuclear fuel stored onsite, is less than the quantity necessary for a critical mass.

  A small quantity of special nuclear material is maintained onsite in forms other than fuel. A typical number and total SNM weight for each of the items is listed below. The small quantities and physical characteristics of these items preclude formation of a critical mass.

    Three excore detectors (~12 grams U-235)
    Thirty-three (33) incore detectors (< 0.5 grams U-235)
    Sixteen (16) source standards (~2x10-5 grams of Pu-239)

- Radiation monitors are provided in storage and associated handling areas.

- The maximum nominal U-235 enrichment of the fresh fuel assemblies is limited to five (5.0) percent by weight.

10 CFR 50.68(b)(8) requires the FSAR to be amended to reflect the licensee's compliance with 10 CFR 50.68(b), no later than the next update per 10 CFR 50.71(e). This update is currently scheduled to be submitted to the NRC no later than six months following the fall 2006 BVPS-2 refueling outage.

Question 9.

This question refers to the licensee's response to Section 5.4, question X.1, of Enclosure 2 of the July 8, 2005, RAI response (pages 294-295). In the EPU report for BVPS-1 and 2, the steam generator tube rupture (SGTR) analysis is based on the assumption that the leak flow from the RCS to the secondary side of the SG is terminated 30 minutes following the event initiation. In response to the NRC staff questions regarding the adequacy of the assumed 30-minute time for terminating the break flow, it is indicated that the Updated Final Safety Analysis Report (UFSAR) was changed to reflect a 51-minute termination time via 10 CFR 50.59. However, the licensee stated that the use of a 30-minute termination time assumed in the methodology still results in a more conservative analysis with respect to the offsite dose consequence analysis. Please prove clarification to substantiate this conclusion.

It is stated in the July 8, 2005, RAI response that a supplemental SGTR analysis has been performed for BVPS-1 that includes the most limiting single failure, coincident with a loss-of-offsite power (LOOP), and with operator actions as assumed in the emergency operating procedures. This supplemental analysis confirmed the conservatism of dose calculations based on the 30-minute termination-of-event assumption. It is also stated that supplemental SGTR analyses have been performed to demonstrate margin to SG overfill for BVPS-1 with various single-failure assumptions considered. Please provide the results of these supplemental SGTR analyses including major assumptions, analyses methodology used, and transient curves developed for the NRC staff to review.

Response:

Refer to responses to Questions 5 & 6 of FENOC Letter L-05-165 dated November 18, 2005 for the requested information.

Enclosure 3 of L-05-177

Westinghouse Affidavit CAW-05-2075

Westinghouse

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Our ref: CAW-05-2075

December 1, 2005

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: FENOC-05-163 P-Attachment, "Response to NRC RAI Question No. 2 (May 26, 2005, Second-Round RAI Questions), Responses to a Request for Additional Information (RAI dated November 1, 2005) in Support of License Amendment Request Nos. 302 and 173" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-05-2075 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by FirstEnergy Nuclear Operating Company.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-05-2075, and should be addressed to B. F. Maurer, Acting Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

BF Maurer

B. F. Maurer, Acting Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: B. Benney
L. Feizollahi

bcc: B. F. Maurer (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
J. J. DeBlasio
R. Surman

CAW-05-2075

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared B. F. Maurer , who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

B. F. Maurer, Acting Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 1st day
of December , 2005

Sharon L Fiori
Notary Public

Notarial Seal
Sharon L. Fiori, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires January 29, 2007
Member, Pennsylvania Association Of Notaries

(1) I am Acting Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use 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 a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in FENOC-05-163 P-Attachment, "Response to NRC RAI Question No. 2 (May 26, 2005, Second-Round RAI Questions), Responses to a Request for Additional Information (RAI dated November 1, 2005) in Support of License Amendment Request Nos. 302 and 173" (Proprietary), for Beaver Valley Power Station, being transmitted by the FirstEnergy Nuclear Operating Company (FENOC) Letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for the Beaver Valley Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of Extended Power Upratings.

This information is part of that which will enable Westinghouse to:

(a) Assist the customer in obtaining NRC approval of Extended Power Uprating by responding to NRC RAIs.

(b) Provide customer specific calculations.

Further, this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for plant-specific applications for other customers.

(b) Its use by a competitor would improve his competitive position in the design and licensing of a similar product.

(c) The information requested to be withheld reveals specific aspects of analysis methodologies which were developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar information and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

Enclosure 4 of L-05-177

Boron Dilution Supplemental Information

The following supplemental information regarding analysis of Boron Dilution events at BVPS is being supplied in response to questions received from the NRC during a teleconference on November 16, 2005.

The NRC reviewer requested that FENOC state the licensing basis for Boron Dilution analyses for BVPS-1 and 2. This request will be used to determine the acceptance criteria applicable to this analysis, specifically, whether or not operator notification time needs to be included in the calculated time to loss of shutdown margin. Currently, in the Mode 3 Boron Dilution analyses performed for BVPS-1 and 2, this time is not included.

Response:

BVPS-1 was licensed to Regulatory Guide 1.70 Rev 0 and predates the Standard Review Plan (SRP) requirements for including the time for operator notification during a Boron Dilution event in the total response time. The current and EPU analyses of the Mode 3 Boron Dilution event were performed consistent with this approach. The BVPS-1 UFSAR includes a general statement in the identification and causes and accident description section for Uncontrolled Boron Dilution which states "The Chemical and Volume Control System is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner." This general statement should not be interpreted as a commitment to the SRP acceptance criteria since this is not part of the BVPS-1 licensing basis.

BVPS-2 was licensed to Regulatory Guide 1.70 Rev 3 and did not take exception to the SRP requirements pertaining to inclusion of operator notification time during a Boron Dilution event. The current and EPU analyses for this event during Mode 3 do not include a time for operator notification. However, as stated in the BVPS-2 UFSAR, the operator will be alerted to the transient by a number of indications. These include the boric acid blender flow integrator audible indication, the boric acid or blended flow rate deviation alarms, increasing audible and indicated count rate on the source range instruments, and the high flux at shutdown alarm. Of these, the first two are directly associated with the changing system conditions which are initiating the event. Malfunctions of the Chemical and Volume Control System blender which results in inadvertent dilution would provide operator notification almost immediately. Therefore, including a time for notification would not change the results or conclusions of the EPU analysis.

Enclosure 5 of L-05-177

Supplemental Information for Change to Technical Specification 3.4.1.3

The following supplemental information regarding the Technical Specification Surveillance Requirement 4.4.1.3.3 and the 28% Narrow Range Span (NRS) established for the replacement steam generators is being provided in response to a question received from the NRC staff.

The change to Technical Specification (TS) 3.4.1.3, Reactor Coolant System – Shutdown, is addressed in RSG LAR Section 2.3, Proposed TS Changes, Change Number 12. This change is discussed in Section 2.3, Proposed TS Changes, Basis for Change Number 12; Section 3.11, Replacement Steam Generator Setpoints, Steam Generator Water Level – Modes 4 and 5; and Section 4.1.11.3, Steam Generator Level.

Change Number 12 consists of revising the steam generator secondary side water level requirement in Surveillance Requirement 4.4.1.3.3 from 12% to 28% narrow range span (NRS) to reflect the replacement steam generators.

The replacement steam generator design change of lowering the narrow range span lower level tap from the upper shell to the transition cone below the top of the tube bundle necessitated that the TS level used to verify operability of the reactor coolant loops be revised.

The water level used to verify steam generator operability is selected such that it is above the top of the tube bundle. This ensures that the steam generators are capable of functioning as a heat sink in Modes 4 and 5 under either forced or natural circulation conditions.

The revised replacement steam generator water level setpoint was calculated to satisfy the functional requirement to have the water level cover the top of the tube bundle so that the U-tubes are completely submerged. Keeping the water level above the top of the tube bundle promotes the capability of the steam generators to function as a heat sink to remove decay heat in Modes 4 and 5 under either forced or natural circulation conditions.

The Technical Specification Surveillance Requirement 4.4.1.3.3 water level of 28% NRS was established for the replacement steam generators based on instrumentation uncertainty and setpoint calculations. The replacement steam generator NRS instrumentation taps are located at distances of 374.8 inches (lower level tap) and 586.8 inches (upper level tap) above the top of the tubesheet. The top of the replacement steam generator tube bundle is located at 417.5 inches above the top of the tubesheet. Thus, the top of the tube bundle is located at 20.14% NRS. Instrument uncertainty calculations determined that the maximum NRS instrumentation uncertainty in Modes 4 and 5 is 7.4% NRS. These values were added together and the result was conservatively rounded up to establish the Technical Specification Surveillance Requirement of 28% NRS. By satisfying the Technical Specification Surveillance Requirement of 28% NRS, it is verified that the replacement steam generator water level is above the top of the tube bundle including consideration of instrumentation uncertainties in Modes 4 and 5. This ensures that the steam generators are capable of providing the heat sink necessary for removal of decay heat in Modes 4 and 5.

Enclosure 6 of L-05-177

List of Commitments

The following list identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 in this document. Any other actions discussed in the submittal represent intended or planned actions by FENOC. They are described only as information and are not regulatory commitments. Please notify Mr. Gregory A. Dunn, Manager, Fleet Licensing at 330-315-7243 of any questions regarding this document or associated regulatory commitments.

Commitment	Due Date
Revise the BVPS-2 UFSAR to reflect compliance with 10 CFR 50.68(b).	Submit to the NRC no later than six months following the fall 2006 BVPS-2 refueling outage.