CP&L
A Progress Energy Company

James Scarola
Vice President
Harris Nuclear Plant

SERIAL: HNP-01-102
10CFR50.4

JUL 1 6 2001

United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555

SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
REGARDING THE STEAM GENERATOR REPLACEMENT AND
POWER UPRATE LICENSE AMENDMENT APPLICATIONS

Dear Sir or Madam:

By letters dated October 4, 2000 and December 14, 2000, Carolina Power & Light Company (CP&L) submitted license amendment requests to revise the Harris Nuclear Plant (HNP) Facility Operating License and Technical Specifications to support steam generator replacement and to allow operation at an uprated reactor core power level of 2900 megawatts thermal (Mwt).

NRC letter dated March 27, 2001 requested additional information to support staff review of the proposed license amendment requests. Our letter SERIAL: HNP-01-078, dated June 11, 2001 responded to each of the staff questions with the exception of question numbers 4, 15, 18, 24, and 26. Our responses to these remaining questions are provided by the Enclosure to this letter.

The enclosed information is provided as a supplement to our October 4, 2000 and December 14, 2000 submittals and does not change the purpose or scope of the submittals, nor does it change our initial determinations that the proposed license amendment applications represent a no significant hazards consideration.

Please refer any questions regarding the enclosed information to Mr. Mark Ellington at (919) 362-2057.

A001

P.O. Box 165
New Hill, NC 27562

T> 919.362.2502
F> 919.362.2095

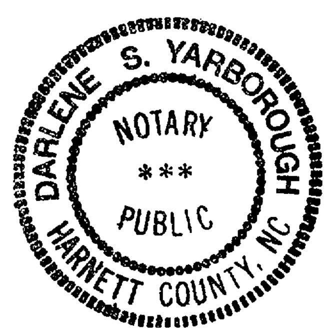
Sincerely,

James Scarola

James Scarola
Vice President
Harris Nuclear Plant

James Scarola, having been first duly sworn, did depose and say that the information contained herein is true and correct to the best of his information, knowledge, and belief, and the sources of his information are employees, contractors, and agents of CP&L.

Darlene S. Yarborough
Notary (Seal)



My commission Expires: 2-21-2005

KWS/kws

Enclosure

c: Mr. J. B. Brady, NRC Senior Resident Inspector
Mr. Mel Fry, NCDENR
Mr. N. Kalyanam, NRC Project Manager
Mr. L. A. Reyes, NRC Regional Administrator

SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
REGARDING THE STEAM GENERATOR REPLACEMENT AND POWER UPRATE
LICENSE AMENDMENT APPLCIATIONS
REACTOR SYSTEMS BRANCH QUESTIONS

Note: Throughout the following questions and responses, the Section, Table, and Figure numbers annotated with an asterisk (*) refer back to the NSSS Licensing Report, Enclosure 6 of the October 4, 2000 license amendment request.

NRC Question 4

Provide a list of the systems or components that are non-safety related and credited in the accident analysis. For each of these non-safety related equipment, provide justification to show the acceptability of its use for consequence mitigation during a transient. Also, item (c)2(ii)(C) of Title 10 of the Code of Federal Regulations (10 CFR) Section 50.36 requires a technical specification (TS) for the systems or components that are used for event mitigation. Accordingly, the licensee is requested to provide the required TSs.

CP&L Response

Provide a list of the systems or components that are non-safety related and credited in the accident analysis. For each of these non-safety related equipment, provide justification to show the acceptability of its use for consequence mitigation during a transient.

In accordance with:

- 10CFR50 Appendix A, Criterion 1 - "Quality Standards and Records,"

- Reg. Guide 1.26 - "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants,"

- ANSI N18.2-1973, and

- ANSI N18.2a-1975,

non-safety systems, structures, and components do not typically provide a mitigation function in the accident analysis. As explained in FSAR Section 15.0.8, control system action is considered in the analysis of the Chapter 15 events only if that action results in more severe accident results. No credit is taken for control system operation if that operation mitigates the results of an accident. For some accidents, the analysis is performed both with and without control system operation to determine the worst case.

While it is not a mitigation function, the initial conditions for the Reactor Coolant System used as a basis for accident analysis rely upon Pressurizer Pressure, Pressurizer Level, and Automatic Rod Control Systems.

A few topics merit additional discussion:

a. Analysis of Anticipated Transients Without Scram (ATWS) is unique. In recognition of the low probability of occurrence (i.e., beyond the original design basis), the generic Westinghouse analysis of this event presented in WCAP-8330 (and, by reference, in FSAR Section 15.8) takes credit for control grade equipment, nominal performance of some systems, and does not apply a single active failure. NRC acceptance of this approach for this event is demonstrated by the prescriptive nature of 10CFR50.62.

b. As noted in the CP&L response to Question 14 (submitted by CP&L letter HNP-01-078, dated June 11, 2001), the non-safety Main Feedwater Flow Control Valves serve as "backup" to the Main Feedwater Isolation (Block) Valves. HNP credits the Main Feedwater Flow Control and Flow Control Bypass Valves to be available to manually isolate and terminate the main feedwater flow, which is consistent with the current licensing basis and the staff position documented in the HNP SER (NUREG-1038).

   The Main Feedwater Flow Control Valves and Flow Control Bypass Valves are classified as Seismic Category I, Quality Group D. These valves are classified as Quality Group D, since they are installed in influent lines and are capable of being isolated from the reactor coolant pressure boundary by an additional valve, the Main Feedwater Isolation Valve (MFIV), which has high leak tight integrity (Ref.: Reg. Guide 1.26). These valves are connected to Non-seismic Category I piping in the Turbine Building and serve as redundant feedwater line isolation designed to fail in the closed position, which with reference to the SER (NUREG-1038), serves as an acceptable backup. The Feedwater Control Valves and the Feedwater Control Bypass Valves are not installed in safety grade piping, but they are important to safety because they act as a backup to the main feed isolation valves during a steam line rupture (Ref.: FSAR 15.1.5.1c). These valves are not expected to remain functional during and/or after a seismic event, since failures of secondary system piping and earthquakes are not required by the NRC to occur simultaneously with each other; i.e., loss of non-safety equipment due to an SSE event is not assumed coincident with a spontaneous steam line break accident. Reliance on the non-safety grade valves in the postulated accident evaluation (Ref.: FSAR 15.1.5.1c) is permitted based on the reliability of these valves. The rationale for dependence on these "non-safety grade" Feedwater Control Valves is that they are high quality components since they are built to ASME Section III, Class 3, Seismic Category I requirements.

Based on the above discussion and information as documented in NUREG-0138, "Staff Discussion Memorandum from Director, NRR to NRR Staff," the feedwater control valves and feedwater bypass control valves are not required to be seismically qualified in their installed condition.

Therefore, HNP has adequate assurance that highly reliable means of isolating feedwater will be available and effective.

c. As part of Control Rod Misoperation documented in FSAR Section 15.4.3, discussion of a Dropped RCCA or RCCA Bank includes Turbine Runback as a protective feature. This function results in an automatic reduction in steam flow through the turbine and is a non-safety function. The analysis is performed with and without Turbine Runback as part of determining the limiting DNBR case. It has a negligible effect on the results, and the limiting case presented in section 6.2.20* is without Turbine Runback.

d. As another part of Control Rod Misoperation in FSAR Section 15.4.3, the discussion of a Statically Misaligned RCCA or RCCA Bank presents a list of indications of the condition. While this list includes rod deviation alarm and rod position indicators, this same list also includes asymmetric core power distributions as seen by the ex-core detectors. Technical Specification 3.2.4 limits the Quadrant Power Tilt Ratio to 1.02 and the corresponding Basis explains that the specific purpose is to allow identification and correction of a dropped or misaligned control rod. In this case, rod position indication is merely an additional level of redundancy.

e. Item 15.1 of FSAR Table 15.0.8-1 includes Turbine Trip in the list of mitigating functions. While the Turbine Trip function is non-safety, it is highly reliable. In addition to a plant operating history in which Reactor Trip has never failed to trip the turbine, ensuring Turbine Trip is one of the key features of ATWS Mitigating System Actuation Circuitry (AMSAC).

f. As a generic concern documented in Westinghouse Nuclear Safety Advisory Letter (NSAL)-00-016, dated December 4, 2000, analysis of Uncontrolled RCCA Bank Withdrawal from a Low Power or Subcritical Condition in FSAR Section 15.4.1 takes implicit credit for the Source Range reactor trip function in Mode 3, 4, or 5 when the power range is not required to be operable. However, Source Range reactor trip may not be fully qualified in terms of response time testing or seismic qualification. This industry issue is under review. In addition, analysis of Inadvertent Boron Dilution for Mode 5 operation in FSAR Section 15.4.6 relies upon the Source Range count rate for detection of the condition. However, operator action provides the actual mitigation in terms of terminating dilution and initiating boration.

Also, item (c)2(ii)(C) of Title 10 of the Code of Federal Regulations (10 CFR) Section 50.36 requires a technical specification (TS) for the systems or components that are used for event mitigation. Accordingly, the licensee is requested to provide the required TSs.

Note that item (c)2(iii) of 10CFR50.36 states the following:

A licensee is not required to propose to modify technical specifications that are included in any license issued before August 18, 1995 to satisfy the criteria in paragraph (c)2(ii) of this section.

Accordingly, modifications to the HNP Technical Specifications to satisfy the criteria in paragraph (c)2(ii) of 10CFR50.36 are not required, since the HNP Operating License was issued prior to August 18, 1995.

NRC Question 15

Section 6.2.3* states that for the increased steam flow event, two cases are analyzed: one for minimum neutronics feedback (beginning-of-cycle (BOC) conditions) and the other for maximum neutronics feedback (end-of-cycle (EOC) conditions). Both cases are evaluated with automatic rod control. The licensee is requested to provide an analysis to show that the cases with automatic rod control are more limiting than the cases without automatic rod control. Also, provide the values of the moderator temperature and Doppler feedback coefficients assumed in the analysis for the BOC and EOC cores and confirm that the analytical values are bounded by the TS values.

CP&L Response

The licensee is requested to provide an analysis to show that the cases with automatic rod control are more limiting than the cases without automatic rod control.

In response to the staff request, an analysis was performed to show that the cases with automatic rod control (ARC) are more limiting than the cases without automatic rod control. The results are provided below for the minimum neutronics feedback (BOC) and maximum neutronics feedback (EOC) conditions with and without ARC. The analysis was performed as a scoping evaluation and confirms that enabling ARC is a bounding assumption.

BOC:

MDNBR = 1.420 (with ARC)
MDNBR = 1.793 (without ARC)

EOC:

MDNBR = 1.432 (with ARC)
MDNBR = 1.449 (without ARC)

Also, provide the values of the moderator temperature and Doppler feedback coefficients assumed in the analysis for the BOC and EOC cores and confirm that the analytical values are bounded by the TS values.

In Table 6.2.3-1, Input Parameters and Biasing for Increase in Steam Flow (provided in Enclosure 3 of our letter SERIAL: HNP-01-078, dated June 11, 2001), it is shown that the Moderator Temperature Coefficients (MTC) used were indeed the (new proposed) Tech Spec limits for the respective times in core life. The pre-uprate EOC MTC limit of –45 pcm/°F required a change to –50 pcm/°F to support the results of neutronics evaluations for SGR/PUR conditions. It is also noted that the actual BOC Tech Spec limit of +5 pcm/°F is actually only applicable up to 70% power, and is required to linearly ramp down to a maximum acceptable value at 100% power of 0.0 pcm/°F. Conservatively, the analysis used the allowable 70% MTC throughout the BOC event.

The Doppler coefficient is shown in the Table 6.2.3-1, Input Parameters and Biasing for Increase in Steam Flow (provided in Enclosure 3 of our letter SERIAL: HNP-01-078, dated June 11, 2001) to be 80% of the respective BOC/EOC values determined by FRA-ANP during the "Neutronics Input to Safety" calculation process. This is in accordance with the FRA-ANP Calculational Guidelines. Reducing the negative feedback from the Doppler coefficient caused the overall power excursion and consequences of the event to be conservatively large.

Numerically, the values of the Moderator temperature and Doppler feedback coefficients assumed in the analysis for the BOC and EOC cores are:

MTC		DTC	
BOC	EOC	BOC	EOC
+5.0 pcm/°F	-50 pcm/°F	-1.0 pcm/°F	-1.4 pcm/°F

NRC Question 18

Section 6.2.13* presents a discussion of the feedwater line break (FLB) accident analysis. The results show that for both FLB cases with and without offsite power available, the pressurizer becomes solid during the event. The safety relief valves are assumed to repeatedly open and close for an extended period of time in the water blowdown environment. TMI action Item II.D.1 requires that all RCS safety, relief, and blocked valves be tested to confirm the valve operability under expected operating conditions for design-basis transients and accidents. Accordingly, the licensee is requested to provide analysis or test data, or reference the NRC approval letter to show that (1) the safety relief valves (SRVs) can be operable (opening and closing on demand) under the water environment, and (2) the SRVs are reliable for repeated opening and closing during a transient for an extended period of time. Also, confirm that the value of initial pressurizer water level used in the pressurizer-overfill analysis maximizes the calculated pressurizer water level and is conservative as compared to the TS value.

CP&L Response

. . . the licensee is requested to provide analysis or test data, or reference the NRC approval letter to show that (1) the safety relief valves (SRVs) can be operable (opening and closing on demand) under the water environment, . . .

The results reported in Section 6.2.13* are intended to address a feedwater line break event with respect to the acceptance criteria listed in FSAR Section 15.2.8. The analysis, however, was not intended to provide for pressurizer safety relief valve (SRV) qualification.

Another analysis, however, has been performed for a main feedwater line break (MFLB) event, consistent with the HNP original licensing basis conditions. The results of this analysis can be used to determine the adequacy of the pressurizer safety relief valves to open and close satisfactorily.

The original analysis and licensing basis was reviewed and accepted by the NRC in their letter to CP&L, R. A. Becker to Lynn W. Eury, dated May 31, 1989, "Evaluation of Carolina Power & Light Company's Shearon Harris, Unit 1, Plant Specific Submittals In Response to NUREG-0737, TMI Action Plan Requirement, Item II.D.I (TAC No.63565)."

The analysis used for SRV qualification assumes plant equipment operation and equipment failures as originally evaluated for HNP initial plant operation with the standard FSAR analyses performed at that time.

Initial plant conditions and equipment performance were assumed which reflect the Steam Generator Replacement and Power Uprate configuration. Other conditions include: offsite power available, no pressurizer sprays operating, loss of turbine-driven auxiliary feedwater pump and one degraded high head safety injection pump operating. Operator action is assumed to terminate high head safety injection (HHSI) and control auxiliary feedwater (AFW) in approximately 30 minutes.

Operator actions to terminate HHSI, control AFW, and initiate plant recovery actions limit the duration of SRV cycling on liquid relief.

Safety Injection termination occurs at 1840 seconds into the event. The pressurizer becomes water solid at 1989 seconds. Liquid relief is postulated to occur for a short period of time subsequent to safety injection termination. Up to approximately 35 minutes into the event, the analysis results indicate a maximum pressure upstream of the SRVs of approximately 2550 psia (safety valve setpoint plus 1% tolerance and 1% setpoint shift), a maximum pressurization rate of 7.4 psi / sec, a SRV inlet temperature range of approximately 606°F to 621°F, and a liquid surge rate into the pressurizer of about 170 gpm.

Each of the above parameters were reviewed and compared to EPRI test data (referenced in the above NRC evaluation) for the Crosby 6M6 safety valves. The analysis results are either bounded by the EPRI test data or are closely represented by the test data. Based on the analysis results and the EPRI test data, the pressurizer SRVs are expected to operate successfully during a liquid discharge for the MFLB event.

In summary, the pressurizer safety valve adequacy for operation with expected conditions for a main feed line break event was reviewed utilizing the original licensing basis assumptions and a Steam Generator Replacement / Power Uprate configuration. These safety valves are expected to reliably open and close repeatedly, on demand, in a water environment for the expected duration that they will operate.

Accordingly, the licensee is requested to provide analysis or test data, or reference the NRC approval letter to show that . . . (2) the SRVs are reliable for repeated opening and closing during a transient for an extended period of time . . .

Please refer to the discussion provided above.

. . . confirm that the value of initial pressurizer water level used in the pressurizer-overfill analysis maximizes the calculated pressurizer water level and is conservative as compared to the TS value.

Section 6.2.13* does not include a "pressurizer–overfill" analysis. Precluding a water solid pressurizer is not a specified acceptance criterion for the FSAR Section 15.2.8 analysis. The pressurizer water level was assumed to be the nominal full power programmed value, which is consistent with typical FSAR Section 15.2.8 assumptions for a MFLB analysis.

The Tech Spec 3.4.3 value requires the pressurizer level to be less than or equal to 92%. The intent of this requirement is to ensure a steam bubble exists for the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressurization transients. This requirement is not intended for use as the initial condition for accident analyses.

NRC Question 24

Section 6.2.27*, CVCS [chemical and volume control system] Malfunction that Increases Reactor Coolant Inventory, states that the potential for water relief through the pressurizer through safety valves is addressed in Event 15.5.1 and the challenge to SAFDL is addressed in Event 15.4.6. The staff notes that the Event 15.5.1 is the inadvertent operation of the ECCS during power operation and Event 15.4.6 is the CVCS malfunction that results in a decrease in the boron concentration event. The referenced cases are caused by different initiators, require different safety systems to mitigate the consequences of the event, may result in different system and thermal-hydraulic responses, and have different safety concerns. The licensee should provide a technical basis to justify that the increased reactor coolant inventory event due to CVCS malfunction is adequately represented by the analysis for Event 15.5.1 and Event 15.4.6, or provide the results of analysis for this event for the staff to review. Also, the licensee states that for Modes 4 through 6, at least one pressurizer PORV (or vent) is available for pressure relief. The licensee should reference the TS for PORVs to satisfy the requirements specified in item (c)2(ii)(C) of 10 CFR 50.36.

CP&L Response

The licensee should provide a technical basis to justify that the increased reactor coolant inventory event due to CVCS malfunction is adequately represented by the analysis for Event 15.5.1 and Event 15.4.6, . . .

The CVCS Malfunction event (FSAR Section 15.5.2), as described in Section 6.2.27* along with the supporting Disposition of Events calculation, was evaluated on a mode-by-mode basis, and the potential consequences were determined to be bounded by the analysis for Event 15.5.1 and Event 15.4.6.

In Modes 1, 2, and 3, the RCS temperature and thermal hydraulic conditions are bounded (on the high temperature side) by the hot full power condition evaluated in the cited 15.5.1 Inadvertent Operation of the Emergency Core Cooling System (IOECCS) event.

The IOECCS analysis results show that the RCS has essentially reached equilibrium at about the 557°F minimum RCS temperature for hot, no-load conditions by the time water relief occurs at around 600 seconds (Reference: Figure 6.2.26-16 included in Enclosure 6 of HNP-00-175, dated December 14, 2000). This ensures that the IOECCS event, starting from full power, adequately bounds the consequences of a similar CVCS malfunction (which would also involve injection of fluid into the RCS to potentially overfill the system) for these Modes 1, 2, and 3 (Power Operation, Startup, and Hot Standby).

In Modes 4, 5, and 6 (these modes are all less than 350°F RCS temperature), at least one PORV (or RCS vent) is available, and provides adequate relief capacity at setpoint pressure equal to or less than 465 psia. Vessel pressure will not approach the pressurizer safety relief valve setpoint with the low temperature overpressure protection available. The event does not challenge the acceptance criterion in these modes.

Section 6.2.27.2* states that the challenge to the SAFDLs for event 15.5.2 (Increase in RCS Inventory) is addressed by event 15.4.6 (Decrease in Boron Concentration). For both events 15.5.2 and 15.4.6, the malfunction of the CVCS that results in the introduction of un-borated water to the RCS via the charging pumps presents the most significant challenge to the SAFDLs. The introduction of unborated water to the RCS results in a dilution of RCS boron causing a reactivity insertion in the core. Since the initiating event is the same for malfunction of the same plant components, the rate of reactivity insertion for both events 15.5.2 and 15.4.6 is equivalent. Since the key response to the initiating event (i.e., reactivity insertion rate) is the same for both events, the challenge to the SAFDLs is the same.

The departure from nucleate boiling (DNB) SAFDL is most challenged by these events due to an increase in core power resulting from the insertion of reactivity. The fuel centerline melt SAFDL is not limiting for these events since the core radial peaking distribution is not redistributed (as it is, for example, for a dropped or misaligned RCC event). The challenge to the DNB SAFDL is most significant prior to reactor scram during Mode 1 operation. The reduced or shutdown power levels for other modes provide significant margin to the DNB SAFDL relative to Mode 1 conditions. Section 6.2.23.2* states that the rate of reactivity insertion (from boron dilution) for event 15.4.6 (Mode 1) is bounded by the range considered in the analysis of event 15.4.1 (Uncontrolled RCCA Withdrawal). The challenge to the DNB SAFDL for event 15.5.2 is shown above to be equivalent to that for event 15.4.6, and both of these events are bounded by the range of reactivity insertion evaluated in Event 15.4.2.

Also, the licensee states that for Modes 4 through 6, at least one pressurizer PORV (or vent) is available for pressure relief. The licensee should reference the TS for PORVs to satisfy the requirements specified in item (c)2(ii)(C) of 10 CFR 50.36.

Harris Plant Tech Specs currently include T.S. 3.4.9.4, which provides for RCS vent and PORV operability in Modes 4, 5, and 6.

NRC Question 26

Section 6.3.2* states that the block valve downsteam of the PORV is credited in the analysis to isolate the PORV from the SG with a ruptured tube. The licensee is requested to discuss the reliability of the block valves to function under the expected transient conditions and address the acceptability of the valves for the accident mitigation. Also, provide a TS LCO for the block valves to satisfy the requirements specified in item (c)2(ii)(C) of 10 CFR 50.36.

As stated in Section 6.3.2*, the licensee determines that an operator can locally close the block valve for the PORV on the affected SG within 20 minutes following the SG PORV failure in the open position. The licensee is requested to discuss the method used to determine the action time for the operator to close the block valve and show that the method is acceptable and the proposed action time of 20 minutes is available.

CP&L Response

The licensee is requested to discuss the reliability of the block valves to function under the expected transient conditions and address the acceptability of the valves for the accident mitigation.

The block valves are manually operated, 8 inch, 900 pound, carbon steel flex wedge gate valves with 6 to 1 bevel gear actuators and indicator rods. The valves are constructed to ASME Class 2, Seismic Category I requirements. The gear actuator is designed to open or close the valve under full unbalanced pressure (based on the maximum operating pressure) so that the manual force does not exceed 100 pounds pull or the coupled action of 50 pounds push–pull. The maximum operating pressure is 1200 psia. By Figure 6.3.2-2*, it is shown that a maximum operating pressure of approximately 1120 psia occurs near the beginning of the SGTR event. In Table 6.3.2-1*, it is shown that the ruptured SG PORV is assumed to fail open at 722 seconds into the event and that the block valve is closed at 1922 seconds into the event (20 minutes later). In Figure 6.3.2-2*, it is shown that the ruptured steam generator pressure decreases from the maximum value to approximately 400 psia prior to the time of block valve closure.

The block valves are included in the ISI program and are stroke tested quarterly during Modes 1 through 4. The test procedure requires that the valves be observed for absence of binding or freewheeling of the valve stem. A review of the maintenance history for each of the valves indicates that no binding or freewheeling problems have been observed in the last 10 years. Based on the above, CP&L concludes that the reliability of the block valves is satisfactory.

Also, provide a TS LCO for the block valves to satisfy the requirements specified in item (c)2(ii)(C) of 10 CFR 50.36.

Note that item (c)2(iii) of 10CFR50.36 states the following:

"A licensee is not required to propose to modify technical specifications that are included in any license issued before August 18, 1995 to satisfy the criteria in paragraph (c)2(ii) of this section."

Accordingly, modifications to the HNP Technical Specifications to satisfy the criteria in paragraph (c)2(ii) of 10CFR50.36 are not required, since the HNP Operating License was issued prior to August 18, 1995.

The licensee is requested to discuss the method used to determine the action time for the operator to close the block valve and show that the method is acceptable and the proposed action time of 20 minutes is available.

The use of the PORV block valve and the operator response time of 20 minutes for local isolation of the valve have not changed as a result of SGR/PUR. A summary of the staff's review and approval of both the HNP SGTR analysis and operator actions and response times prior to SGR/PUR is documented in a letter from the NRC's R.S. Becker to CP&L's L.W. Eury dated December 19, 1990.

The block valves are located upstream of the main steam PORVs in the main steam tunnel near the 283 foot elevation. A platform runs just beneath the valves allowing easy operator access to the valves. The main steam tunnel can be accessed via one of two doors located at the 261 foot elevation of the Reactor Auxiliary Building.