ATTACHMENT 2

TECHNICAL EVALUATION REPORT

Washington Public Supply System
Nuclear Plant No. 2
Pump and Valve Inservice Testing Program
Revision 0, Second Ten-Year Interval

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ABSTRACT

This report presents the results of Brookhaven National Laboratory's evaluation of the pump and valve relief requests prepared under the Washington Public Power Supply's Nuclear Plant No. 2 (WNP-2), ASME Section XI Pump and Valve Inservice Testing Program.

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1. INTRODUCTION

Contained herein is a technical evaluation report (TER) of Revision 0 of the ASME Section XI Second Ten Year Program for pump and valve inservice testing (IST) submitted to the U.S. Nuclear Regulatory Commission (NRC) by Washington Public Power Supply for its Nuclear Plant No. 2 (WNP-2) on December 16, 1994 (Ref. 1). The program for this second ten year interval is based on the requirements of Section XI of the ASME Boiler and Pressure Vessel Code, 1989 Edition (Ref. 2). The 1989 Edition of Section XI provides that the rules for inservice testing of pumps and valves are as specified in ASME/ANSI OMa-1988 Parts 1, 6 and 10 (Refs. 3, 4 5), respectively.

This program revision supersedes all previous submittals. WNP-2 is a General Electric Boiling Water Reactor (BWR) which began commercial operation on December 13, 1984. The second ten year inspection interval is defined for WNP-2 as beginning December 13, 1994 and ending December 12, 2004.

Title 10 of the Code of Federal Regulations, §50.55a ¶(f) (Ref. 6) requires that inservice testing of ASME Code Class 1, 2, and 3 pumps and valves be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda, except where specific relief has been requested by the licensee and granted by the commission pursuant to §50.55a ¶(a)(3)(i), (a)(3)(ii), or (f)(6)(i). Washington Public Power Supply has requested relief from certain ASME Section XI testing requirements. A review of the relief requests was performed using Section 3.9.6 of the Standard Review Plan (Ref. 7); Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," (Ref. 8), and the Minutes of the Public Meeting on Generic Letter 89-04, dated October 25, 1989 and September 26, 1991 (Refs. 9 and 10); and Supplement 1 to Generic Letter 89-04 which contains NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," (Ref. 11). The IST Program requirements apply only to component (i.e., pump and valve) testing and are not intended to provide a basis to change the licensee's current Technical Specifications for system test requirements.

Section 2.0 of this report presents the evaluation of six pump relief requests. Section 3.0 presents the evaluation of five valve relief requests. Section 4.0 summarizes the actions required of the licensee resulting from the TER evaluations of the relief requests. Section 5.0 lists the references. (Based on this task's statement of work, evaluations of justifications for deferring testing, licensee technical positions, programmatic aspects, and systems reviews are not considered in this technical evaluation report).

2. PUMP RELIEF REQUESTS

In accordance with §50.55a, Washington Public Power Supply System has submitted seven relief requests for pumps at its Nuclear Plant No. 2 (WNP-2) which are subject to inservice testing under the requirements of OMa-1988, Part 6. Relief was not required for RP06, since the licensee's proposal complies with the Code requirements (i.e., the diesel oil transfer system resistance cannot be varied, and per the Code compliance with 5.2(c) is required). This request is therefore not evaluated in this section. The other six relief requests, along with their technical evaluation by BNL, are summarized below.

2.1 Standby Service Water and High Pressure Core Spray Service Water Pumps

There are two relief requests that relate to the measurement of differential pressure and reference values for standby service water pumps, SW-P-1A and B, and high pressure core spray service water pump, HPCS-P-2.

2.1.1 Differential Pressure, Relief Request RP01

Relief Request: The licensee has requested relief from the requirements of Part 6, ¶5.2, Table 2 for measuring differential pressure for vertical line shaft type pumps.

Proposed Alternate Testing: The licensee has proposed measuring and evaluating pump discharge pressure during testing of these pumps, in lieu of differential pressure.

Licensee's Basis for Relief: The licensee's basis for relief is:
"1) SW-P-1A, 1B, and HPCS-P-2 are vertical line shaft type pumps which are immersed in their water source. They have no suction line which can be instrumented.

2) Technical Specifications state minimum allowable spray pond level to assure adequate NPSH and ultimate heat sink capability.

3) The difference between allowable minimum and overflow pond level is only twenty one (21) inches of water or 0.8 psi. This small difference will not be significant to the Test Program and suction pressure will be considered constant. Administratively, the pond level is controlled within a nine (9) inch band.

4) Acceptable flowrate and discharge pressure will suffice as proof of adequate suction pressure.

The effect of setting the Code Acceptance Criteria on discharge pressure instead of differential pressure as specified in the Code will have no negative impact on detecting pump degradation. A review of the discharge pressure gauge reading, which is uncorrected for elevation, compared to differential pressure readings shows that basing corrective action on discharge pressure is slightly more conservative than basing it on differential pressure for these pump installations."

Evaluation: The licensee has requested relief from the Part 6, ¶5.2, Table 2 requirement for measuring differential pump pressure during quarterly testing of the standby service water and high pressure core spray service water pumps. The licensee proposes instead to measure and evaluate the pumps' operational readiness based on the discharge pressure of these pumps because inlet suction pressure instrumentation is not available.

NUREG-1482, Section 5.5.3, allows the use of fluid level for calculating suction pressure and determining differential pressure when direct measurement of inlet pressure or differential pressure is not available. The calculation must be included in an implementing procedure and meet quality assurance requirements. By including the calculation in implementing procedures, the licensee can determine the differential pressure in a manner that is consistent and repeatable from test to test. The Code in ¶ 4.6.2.2 allows the licensee to determine differential pressure using a calculational method by determining the difference between the pressure at a point in the inlet pipe and a pressure at a point in the discharge pipe. Therefore, the licensee may implement a calculational method without obtaining relief because the ASME Code allows for the determination of differential pressure from the discharge pressure and the pressure in the pump inlet. From the information submitted in the request, it does not appear to be impractical for the licensee to calculate differential pressure based on pond level. However, the licensee has proposed that determining the pumps' operational readiness based on discharge pressure provides an equivalent level of quality and safety.

As discussed by the licensee the difference between minimum and overflow pond level is only 21 inches of water, or 0.8 psi, which is further administratively controlled to a

9 inch band, which equates to 0.33 psi. This small variation makes the suction pressure essentially constant. Based on Relief Request RP03, the service water pumps' discharge pressure could range from 185 psig to 240 psig making the 0.33 psig subtraction less than 0.2 % of discharge pressure. In addition, the licensee infers that measuring discharge pressure is more conservative for these pumps because the measurement is uncorrected for elevation. It is assumed that the bay level is at a lower elevation than the discharge piping, thus the discharge pressure is smaller than the pump differential pressure simply because of the difference in static head.

Therefore, provided that the discharge pressure is less than the calculated differential pressure considering the entire range of suction pressures, such that the acceptance criteria assigned to the discharge pressure gives equivalent protection provided by the Code for differential pressure, it is recommended that the licensee's proposal be authorized pursuant to 10CFR50.55a ¶ (a)(3)(i), based on an equivalent level of quality and safety as the Code.

2.1.2 Reference Values, Relief Request RP03

Relief Request: The licensee has requested relief from the requirements of Part 6, ¶5.2(b) which requires that the system resistance be varied until either the measured differential pressure or measured flow rate equals the corresponding reference value. The quantities of Table 2 are then measured or observed and compared to the corresponding reference value.

Proposed Alternate Testing: The licensee proposes, as an alternate to the testing requirements of Paragraph 5.2, to base the acceptance criteria on a reference curve. Flow rate and discharge pressure are measured during inservice testing in the as found condition and compared to an established reference curve. Discharge pressure instead of differential pressure is used to determine pump operational readiness as described in Relief Request RP01. The following elements are used in developing and implementing the reference pump curves.

1) A reference pump curve (flow rate vs discharge pressure) has been established for SW-P-IA and SW-P-1B from data taken on these pumps when they were known to be operating acceptably. These pump curves represent pump performance almost identical to preoperational test data. The methodology employed for establishing a reference pump curve is similar to that for performing a comprehensive test proposed by the later edition of the OM Code.

2) Pump curves are based on seven or more test points beyond the flat portion of the curve (at flow rate greater than 4800 gpm). Rated capacity of these pumps is

12,000 gpm. Three or more test data points were at flow rate greater than 9,000 gpm. The pumps are being tested at or near full design flow rate.

3) To reduce the uncertainty associated with the pump curves and the adequacy of the acceptance criteria, special test gauges (± 0.5 % full scale accuracy) were installed to take test data in addition to plant installed gauges and Transient Data Acquisition System (TDAS). All instruments used either met or exceeded the Code required accuracy.

4). For HPCS-P-2 pump, the reference pump curve is based on the manufacturer's pump curve as modified by preoperational test data.

5) Review of the pump hydraulic data trend plots indicates close correlation with the established pump reference curves, thus further validating the accuracy and adequacy of the pump curves to assess pump operational readiness.

6) The reference pump curves are based on flow rate vs discharge pressure. Acceptance criteria curves are based on differential pressure limits given in Table 3b. Setting the Code Acceptance Criteria on discharge pressure using differential limits is slightly more conservative for these pump installations with suction lift (Relief Request RP01). See the attached sample SW-P-IA pump Acceptance Criteria sheet [Not included in TER]. Area 1-2-5-6 is the acceptable range for pump performance. Area 3-4-5-6 defines the Alert Range, and the area outside 1-2-3-4 defines the required Action Range. These acceptance criteria limits do not conflict with Technical Specifications or FSAR criteria.

7) Only a small portion of the established reference curve is being used to accommodate flow rate variance due to flow balancing of various system loads.

8) Review of vibration data trend plots indicates that the change in vibration readings over the narrow range of pump curves being used is insignificant and thus only one fixed reference value has been assigned for each vibration measurement location.

9) After maintenance or repair that may affect the existing reference pump curve, a new reference pump curve shall be determined or the existing pump curve revalidated by an inservice test. A new reference pump curve shall be established based on at least 5 points beyond the flat portion of the pump curve.

Licensee's Basis for Relief: The licensee states: "It is extremely difficult or impossible to return to a specific value of flow rate or discharge pressure for testing of these

pumps. Multiple reference points could be established according to the Code, but it would be impossible to obtain reference values at every possible point, even over a small range.

1) Service Water systems are designed such that the total pump flow cannot be adjusted to one finite value for the purpose of testing without adversely affecting the system flow balance and Technical Specification operability requirements. Thus, these pumps must be tested in a manner that the Service Water loop remains properly flow balanced during and after the testing and each supplied load remains fully operable to maintain the required level of plant safety.

2) The Service Water system loops are not designed with a full flow test line with a single throttle valve. Thus, the flow cannot be throttled to a fixed reference value. Total pump flow rate can only be measured using the total system flow indication installed on the common return header. There are no valves in any of the loops, either on the common supply or return lines, available for the purpose of throttling total system flow. Only the flows of the served components can be individually throttled. Each main loop of service water supplies 17-18 safety related loads, all piped in parallel with each other. The HPCS-P-2 pump loop supplies four loads, each in parallel. Each pump is independent from the others (i.e., no loads are common between the pumps). Each load is throttled to a FSAR required flow range which must be satisfied for the loads to be operable. All loads are aligned in parallel, and all receive service water flow when the associated service water pump is running, regardless of whether the served component itself is in service. During power operation, all loops of service water are required to be operable per Technical Specifications. A loop of service water cannot be taken out of service for testing without entering an Action Statement for a Limiting Condition for Operation (LCO). Individual component flows outside of the FSAR mandated flow ranges also induce their own Technical Specification action statements that in turn can induce plant shutdown in as little as two hours, depending on the load in question.

3) Each loop of Service Water is flow balanced before exiting each refueling outage to ensure that all loads are adequately supplied. A flow range is specified for each load. Once properly flow balanced, very little flow adjustment can be made for any one particular load without adversely impacting the operability of the remaining loads (increasing flow for one load reduces flow for all the others). Each time the system is flow balanced, proper individual component flows are produced, but this in turn does not necessarily result in one specific value for total flow. Because each load has an acceptable flow range, overall system full flow (the sum of the individual loads) also has a range. Total system flow can conceivably be in the ranges of approximately 9,200 - 10,100 GPM for SW-P-IA and SW-P-1B pumps and approximately 1,050 -

1,160 GPM for HPCS-P-2 pump. Consequently, the requirement to quarterly adjust service water loop flow to one specific flow value for the performance of inservice testing conflicts with system design and component operability requirements (i.e., flow balance) as required by Technical Specification."

"Design of the WNP-2 Service Water system and the Technical Specification requirements make it impractical to adjust system flow to a fixed reference value for inservice testing without adversely affecting the system flow balance and Technical Specification operability requirements. Proposed alternate Testing using a reference pump curve for each pump provides adequate assurance and accuracy in monitoring pump condition to assess pump operational readiness and shall adequately detect pump degradation. Alternate testing will have no adverse impact on plant and public safety."

Evaluation: The licensee has requested relief from Part 6, ¶5.2(b), which requires establishing a fixed set of reference values for either flow or differential pressure. It is impractical to alter pump flow rates to obtain repeatable reference values because the standby and HPCS service water pumps supply cooling water to multiple safety-related loads which are located in several flow balanced loops without throttle valves. Varying the flow rate of one of the safety loads affects the system flow balance and the Technical Specification operability requirements. Installing throttling valves that can throttle total system flow would be a burden because of the design, fabrication, and installation changes that would have to be made. The licensee proposes to use pump curves instead of reference values.

In NUREG-1482, Section 5.2, the NRC staff provides guidance for utilizing pump curves when it is impractical to establish a fixed set of reference values. The licensee complies with the seven elements identified in Section 5.2. In fact, this relief request (with appropriate changes from IWP references to Part 6 references) is given as an example of an acceptable relief request in pages C.11 through C.14 of Appendix C to NUREG-1482.

It is recommended that relief be granted in accordance with 10CFR50.55a ¶ (f)(6)(i), based on the impracticality of complying with the Code and that the alternative provides an acceptable level of quality and safety.

2.2 Diesel Fuel Oil Transfer Pumps, Relief Request RP02

Relief Request: The licensee has requested relief from Part 6, ¶4.6.5, which requires that the flow rate be measured using a rate or quantity meter installed in the pump test circuit for the diesel fuel oil transfer pumps DO-P-1A, DO-P-1B, and DO-P-2.

Proposed Alternate Testing: The licensee has proposed that the pump flow rate will be determined by measuring the volume of fluid pumped and dividing by the corresponding pump run time. The volume of fluid pumped will be determined by the difference in fluid level in the day tank at the beginning and end of the pump run (day tank fluid level corresponds to volume of fluid in the tank). The licensee states that the pump flow rate calculation methodology meets the accuracy requirements of OM Part 6, Table 1.

The day tanks are horizontal cylindrical tanks with elliptical ends. The tank fluid volume is approximately 3,200 gallons. Fluid level measurement is accurate to an eighth inch, which corresponds to an average volume error of approximately 11 gallons. The test methodology used to calculate pump flow rate will provide results consistent with Code requirements. This will provide adequate assurance of acceptable pump performance.

Licensee's Basis for Relief: The licensee states: "A rate or quantity meter is not installed in the test circuit. To have one installed would be costly and time consuming with few compensating benefits."

Evaluation: OM Part 6, ¶4.6.5 states that pump flow rate measurements shall be made using a rate or quantity meter installed in the pump test circuit. The accuracy of these meters is specified in Table 1 of Part 6 (i.e., ±2%). Diesel fuel oil transfer pumps DO-P-1A, 1B, and 2 transfer diesel generator fuel oil from the subterranean storage tanks to the diesel's day tanks. The discharge lines of Pump 1A and 1B are cross tied, and each pump can supply fuel to either diesel 1A or 1B. Pump 2 is dedicated to the HPCS diesel. As stated by the licensee in the Basis for Relief, and confirmed by a review of the P&IDs, flowmeters which could be utilized to measure the flowrate from these pumps are not installed in the system. The licensee states that installation of such instrumentation would require significant system design changes, which would be costly and burdensome to the licensee. As stated in the response to Question 105 in the Minutes of the Public Meeting on Generic Letter 89-04, the NRC does not necessarily consider the installation of instrumentation to be impractical. However, as stated in the Response to Comment 5.5-5 in NUREG-1482, if an equivalent means of determining the measured parameter is available, installation of a permanent instrument would not be required. In addition, the licensee states in the Basis of Pump Relief Request RP06 that the "Use of a clamp-on flow meter does not provide an accurate and repeatable flow rate due to low flow rate and lack of time available to set up the flow meter with the pump running."

The licensee's proposed alternative to calculate the flow rate based on pump operating time and level changes in the day tank will provide an acceptable alternative

to the Code requirements. The licensee states that the calculational method meets the Code accuracy requirements. The licensee has determined that the error from measuring the level changes in the tank corresponds to 11 gallons. This represents a 0.3% (0.6% total) error for the tank volume of 3200 gallons, although the tank volume used during the test will be smaller. Therefore, based on the impracticality of installing permanent instrumentation, the difficulty associated with using portable flowmeters, and that the licensee's proposed method of calculating flowrate provides a reasonable alternative to the Code requirements, it is recommended that relief be granted pursuant to §50.55a ¶(f)(6)(i). The licensee should ensure that the calculational method is properly proceduralized and meets quality assurance requirements.

2.3 Emergency Core Cooling Pumps

There are two relief requests related to emergency core cooling pumps. The first concerns itself with reference values for flow and differential pressure for the low pressure core spray (LPCS-P-1), high pressure core spray (HPCS-P-1), residual heat removal (RHR-P-2A through C), and reactor core isolation cooling (RCIC-P-1) pumps. The second request concerns itself with allowable instrument range for the RHR and HPCS pumps.

2.3.1 LPCS, HPCS, RHR, RCIC Reference Values, Relief Request RP04

Relief Request: The licensee has requested relief from the requirements of Part 6, ¶5.2(a) and (b), which require that the speed of a variable speed driver be adjusted to the reference value and the system resistance be varied until either the measured differential pressure or measured flow rate equals the corresponding reference value, respectively. The quantities of Table 2 are then measured or observed and compared to the corresponding reference value.

Proposed Alternate Testing: The licensee has proposed using a reference pump curve for each pump. Specifically:

"1) A reference pump curve (flow rate vs differential pressure) has been established for RHR pumps from data taken on these pumps when they were known to be operating acceptably. These pump curves represent pump performance almost identical to manufacturer's test data. The methodology employed for establishing a reference pump curve is similar to that for performing a comprehensive test proposed by the later edition of the OM Code.

2) For RCIC-P-1, a variable speed drive pump, flow rate is set within ± 2% of the reference flow rate and the reference curve is based on speed with acceptance criteria based on differential pressure. This is done because of the difficulty in setting speed to a specific reference value as specified by the Code. Additionally, evaluation of the manufacturer pump data, preoperational and special test data used to establish the pump reference curve indicates insignificant change (0.25 psi/gpm) in differential pressure with small variation(± 12 gpm) in flow rate.

3) For HPCS-P-1 and LPCS-P-1 pumps, the reference pump curve is based on the manufacturer pump curve which was validated during the preoperational testing.

4) RHR and RCIC pump curves are based on seven or more test points beyond the flat portion of the curve. These ECCS pumps have minimum flow rate requirements specified in Technical Specifications and are being tested at or near full design flow rate.

5) To reduce the uncertainty associated with the pump curves and to ensure the adequacy of the acceptance criteria, special test gauges (± 0.5% full scale accuracy) were installed to take test data in addition to plant installed gauges and Transient Data Acquisition System (TDAS). All instruments used either met or exceeded the Code required accuracy.

6) Review of the pump hydraulic data trend plots indicates close correlation with the established pump reference curves, thus further validating the accuracy and adequacy of the pump curves to assess pumps operational readiness.

7) Acceptance criteria curves are based on differential pressure limits given in Table 3b. These acceptance criteria limits do not conflict with Technical Specifications or Final Safety Analysis Report operability criteria.

8) Only a small portion of the established reference curve is being used to accommodate flow rate variance.

9) Review of vibration data trend plots indicates that the change in vibration readings over the narrow range of pump curves being used is insignificant and thus only one fixed reference value has been assigned for each vibration measurement location.

10) After maintenance or repair that may affect the existing reference pump curve, a new reference pump curve shall be determined or the existing pump curve revalidated

by an in service test. A new reference pump curve shall be established based on at least 5 test points beyond the flat portion of the pump curve."

"Since the independent reference variable (flow rate) for these pumps is very difficult to adjust to a fixed reference value and requires excessive valve manipulation, the maximum variance shall be limited to ± 2% of the reference value. Thus, flow rate shall be adjusted to be within ± 2% of the reference flow rate and the corresponding differential pressure shall be measured and compared to the reference differential pressure value determined from the pump reference curve established for this narrow range of flow rate."

Licensee's Basis for Relief: The licensee states: "Reference values are defined as one or more fixed sets of values of quantities as measured or observed when the equipment is known to be operating acceptably. All subsequent test results are to be compared to these reference values. Based on operating experience, flow rate (independent variable during inservice testing) for these pumps cannot be readily duplicated with the existing flow control systems. Flow control for these systems can only be accomplished through the operation of relatively large motor operated globe valves as throttling valves. Because these valves are not equipped with position indicators which reflect percent open, the operator must repeatedly jog the motor operator to try to make even minor adjustments in flow rate. These efforts, to exactly duplicate the reference value, would require excessive valve manipulation which could ultimately result in damage to valves or motor operators.

ASME Code allows establishing multiple reference points but does not specify any variance from the fixed reference values. Since the dependent variable (differential pressure) can be assumed to vary linearly with flow rate in this narrow range, establishing multiple reference points in this narrow range is similar to establishing a reference pump curve representing multiple reference points. This assumption of linearity between differential pressure and flow rate is supported by the manufacturer pump curves in the stable design flow rate region.

Due to impracticality and difficulty of adjusting independent variables (flow rate, and speed for variable drive RCIC pump) to a fixed reference value for inservice testing without system modifications, alternate testing to vary the variables over a very narrow range (± 2% of reference values) and using pump reference curves for this narrow range is proposed."

Evaluation: OM Part 6 ¶5.2(a) requires that the speed of a variable speed driver be adjusted to the reference value. Paragraph (b) requires that the system resistance be varied until either the measured flowrate or differential pressure equals the

reference values. As discussed in Section 5.2 of NUREG-1482, the NRC considers the use of pump curves acceptable when it is impractical to establish a fixed set of reference values. Pump curves represent an infinite set of reference flowrate and differential pressure points, or in the case of the RCIC pump, an infinite set of reference differential pressures and speeds. Establishing a reference curve for a pump when it is known to be operating acceptably, and basing the acceptance criteria on this curve, can allow the pumps condition to be evaluated and degradation detected.

The licensee has stated in the Basis for Relief that it is impractical to adjust the pump flowrate to obtain repeatable reference values for the RHR, LPCS, and HPCS pumps, and pump speed for the RCIC pump. Large motor-operated globe valves are used as flow control valves in these systems. Since these valves do not have position indication, achieving repeatable settings is not practical. Installing other flow control valves which have more accurate flow adjustment capability would be a burden to the licensee due to design, fabrication, and installation changes which would be necessary.

The licensee has generated reference pump curves for each pump referenced in this relief request. The sample curve submitted by the licensee with this relief request (for pump RHR-P-2A) reflects a ±2% variance in the pump flow rate. As stated by the licensee, these curves were generated with the pumps operating acceptably. These curves were generated using instruments which meet the accuracy requirements of the Code. The range covered by the curve does not reside on the flat portion of the pump curve, and its acceptance criteria is based on the differential pressure limits specified in OM Part 6 Table 3(b). The licensee has also stated that these acceptance limits do not conflict with the technical Specification or FSAR operability criteria. The licensee has also stated that the pump vibration does not vary significantly over the narrow range of pump curves being used, and only one fixed reference value has been assigned for each vibration measurement location. Following pump maintenance, the pump curve will be revalidated, or a new one generated. The method for developing and utilizing pump curves as provided by the licensee is in accordance with the guidance provided in NUREG-1482, Section 5.2, and provides an acceptable alternative to using fixed reference values.

It is recommended that relief be granted pursuant to §50.55a ¶(f)(6)(i), based upon the impracticality of performing the testing in accordance with the Code, and in consideration of the burden on the licensee if the Code requirements were imposed upon the facility.

2.3.2 RHR, HPCS Instrument Range, Relief Request RP05

Relief Request: The licensee has requested relief from the requirements of Part 6, ¶4.6.1.2(a), which requires that the full scale range of each analog instrument shall be not greater than three times the reference value.

Proposed Alternate Testing: The licensee has proposed that during quarterly pump inservice testing, pump discharge pressure, which is used to determine differential pressure, shall be measured by respective transient data acquisition system (TDAS).

Licensee's Basis for Relief: The licensee states:
"1) Paragraph 4.6 specifies both accuracy and range requirements for each instrument used in measuring pump performance parameters. The purpose of instrument requirements is to ensure that pump test measurements are sufficiently accurate and repeatable to permit evaluation of pump condition and detection of degradation. Instrument accuracy limits the inaccuracy associated with the measured test data. Thus, higher instrument accuracy lowers the uncertainty associated with the measured data. The purpose of the Code range requirement is to ensure reading accuracy and repeatability of test data.

2) Since the TDAS data is being obtained to an accuracy of ± 1% of full scale, it consistently yields measurements more accurate than would be provided by instruments meeting the Code instrument accuracy requirement of ± 2% of full scale and range requirement of three times the reference value. Equivalent Code accuracy being obtained by TDAS measurements is calculated below.

Pump	Test Parameter	Instrument I.D.	Range (PSIG)	*Ref Value (PSIG)	Instrument Loop Accuracy	Equivalent Code Accuracy
RHR-P-2A	Discharge Pressure	RHR-PT-37A TDAS PT 155	0-600	136	± 1%, ± 6 psig	6/(3x136)x100 = 1.47%
RHR-P-2B	Discharge Pressure	RHR-PT-37B TDAS PT 076	0-600	132	± 1%, ± 6 psig	6/(3x132)x100 = 1.52%
RHR-P-2C	Discharge Pressure	RHR-PT-37C TDAS PT 091	0-600	143	± 1%, ± 6 psig	6/(3x143)x100 = 1.40%
HPCS-P-1	Discharge Pressure	HPCS-PT-4 TDAS PT 107	0-1500	430	± 1%, ± 15 psig	15/(3x430)x100 = 1.16%

*Reference values are specified in the implementing procedures. This table will not be updated to reflect changes in reference values.

Thus the range and accuracy of TDAS instruments being used to measure pump discharge pressure result in data measurements of higher accuracy than that required by the Code and thus will provide reasonable assurance of pump operational readiness. It should also be noted that the TDAS system averages many readings, therefore giving a significantly more accurate reading than would be obtained by visual observation of a gauge.

3) Installing temporary test gauges every quarter to obtain discharge pressure readings would be burdensome and costly and would not provide a pressure measurement that is any more accurate or reliable. Additionally, using different test gauges for IST from one test to another may introduce its unique systematic error and thus affect the quality and repeatability of test data."

Additionally, the licensee states: "TDAS data will consistently provide acceptable accuracy to ensure that the pumps are performing at the flow and pressure conditions to fulfill their design function. TDAS data is sufficiently accurate for evaluating pump condition and in detecting pump degradation. Test quality will be enhanced by getting slightly better, more repeatable data."

Evaluation: OM Part 6 ¶4.6.1.2(a) states that the full scale range for analog instruments shall not exceed three times the reference value. The pressure instruments accuracy must be within ±2% of the full scale for analog instruments. The licensee has proposed measuring discharge pressure for the RHR and HPCS pumps using instruments which exceed this limit. As discussed in NUREG-1482, Section 5.5.1, if the range of installed analog instruments is greater than three times the reference value, relief may be granted if the combination of the range and accuracy yields a reading accuracy at least equivalent to that obtainable from instruments which meet the Code requirements (i.e., ±6%).

As stated by the licensee in the Basis for Relief, the accuracy of the installed pressure indicators are calibrated to ±1% of full scale. The actual reading accuracy which would be obtained from using these instruments (i.e., between 3.5% to 4.5%) is better than required by the Code (i.e., 6%). Therefore, the installed instrumentation provides an acceptable of level of quality and safety. Using temporary test gauges would represent an increased burden and cost to the licensee, without a compensating increase in quality and safety.

It is recommended that the alternative to the Code instrument accuracy requirements be approved pursuant to §50.55a ¶(a)(3)(i), based on the alternative providing an acceptable level of quality and safety. In the event these instruments are replaced, the licensee should, however, install instruments which meet the Code requirements.

2.4 Standby Liquid Control Pumps, Relief Request RP07

Relief Request: The licensee has requested relief from Part 6, ¶4.6.1.6, which requires that the frequency response range of the vibration measuring transducers and their readout system shall be from one third minimum pump shaft rotational speed to at least 1000 Hz, for the Standby Liquid Control pumps (SLC-P-1A and B).

Proposed Alternate Testing: The licensee has proposed that the vibration measurements will be taken using instrumentation accurate to within ± 3% of full scale over a frequency range of 6 Hertz to 3 Kilohertz. All deviations from the reference values shall be compared with the limits given in Part 6, Table 3 and corrective actions taken as specified in Part 6, paragraph 6.1.

Licensee's Basis for Relief: The licensee states that pumps: "SLC-P-1A and 1B inject borated water into the reactor vessel as an alternate means of introducing negative reactivity to shutdown the reactor.

1) The motor speed of 30 Hertz is transferred to the pump shaft through a 4.8:1 ratio gear box which reduces motor speed and produces a shaft rotation of 6.25 Hertz. Paragraph 4.6.1.6 requires a frequency range of one third pump shaft rotating frequency to one Kilohertz; in this case that frequency range is 2 Hertz through one Kilohertz ± 5%. A search for field applicable certifiable instrumentation that can satisfy these criteria has been unsuccessful.

2) Vibration instruments include high-pass filters in the signal processing scheme for the purpose of estimating low frequency electronic noise. Low frequency vibration is thus filtered out of the processed signal. This is a common practice in nearly all available field usable instrumentation, because there is no requirement for collecting vibration data at such low frequencies. Thus, the procurement of practical, field applicable instrumentation capable of accurate detection down to 2 Hertz is improbable.

3) The Supply System uses high quality instrumentation that has been certified to a lower frequency range of six Hertz and an upper range of three Kilohertz with an accuracy of at least ± 5%, and meets the other requirements of the Code for plant rotating machinery. This instrumentation has been made part of the Quality Class I calibration program, which is traceable to the National Bureau Of Standards, and is used for Quality Class I rotating machinery vibration data collection, including the SLC pumps.

4) The requirement of one third minimum pump shaft rotation speed is useful when subsynchronous vibration frequencies must be monitored. Subsynchronous vibration monitoring can be used to identify rotor dynamic problems that are common in rotating machines such as shaft rubs, fluid whirl in journal bearings, axial instabilities, and other such problems that are not normally found in reciprocating machines. The necessity of collecting subsynchronous vibration data on the SLC pumps was discussed with the manufacturer. The Union Pump Company agreed that vibration data at less than rotating frequency would not be necessary.

5) The SLC pumps at WNP-2 operate only during required surveillance testing, and thus experience very little service, such that a mechanical fault is very unlikely. Moreover, the SLC pumps are included in the WNP-2 Vibration Monitoring Program, as well as in the IST program. The Vibration Monitoring Program collects vibration data on plant machinery, and analyzes and trends the collected vibration data for use in maintenance decisions, as well as machinery operability determinations. The SLC Pumps have been monitored since November 1993. Their spectra is consistent and has shown only minor statistical changes during the period of surveillance. The subsynchronous region shows a very low amplitude and consistent pattern, as expected."

Additionally, the licensee states: "The Supply System is of the opinion that the use of high quality, commercially available vibration monitoring equipment calibrated to be accurate to at least ± 3% over a range of 6 Hertz to 3 Kilohertz is a technically acceptable method of monitoring the mechanical condition of the SLC pumps. The instruments that are used provide meaningful and useful vibration data over the frequency range in which pump faults would be expected to develop and manifest. In addition to this, the 3 Kilohertz range includes the frequencies at which rolling element bearing faults occur, and thus provides an additional range of protection. Thus, the monitoring program meets the intent of the Code and will neither adversely impact system reliability nor the health and safety of the general public."

Evaluation: The Code requires that the frequency response range for vibration instruments shall be from one third minimum pump shaft rotational speed to at least 1000 Hz. The lower response limit was selected by the ASME Code committee to provide greater assurance that all potential noise contributors that could indicate pump degradation are detected. The standby liquid control (SLC) pumps are slow speed positive displacement pumps with a shaft speed of 6.25 Hz. Compliance with the Code for these pumps would require vibration instruments with a frequency response down to 2 Hz. These pumps are in standby and normally operate only during surveillance testing.

The licensee has proposed to utilize instruments with a frequency response of 6 to 3000 Hz. The licensee has consulted with the pump manufacturer, Union Pump Company, and has stated that problems identified by subsynchronous vibrations are not normally found in reciprocating machines, and that monitoring at less than the rotating frequency is not necessary. The licensee has also stated that these pumps are included in a vibration monitoring program, separate from the IST program, which uses spectral analysis to trend and analyze data. The vibration monitoring program examines subsynchronous vibration, and should provide additional assessment of pump degradation.

The licensee has stated that they have been unable to locate instruments that can detect vibration down to 2 Hz. However, as discussed in NUREG-1482, Section 5.4, instruments in low frequency response ranges have recently been made commercially available. Other licensees, such as Northern States Power at the Monticello Nuclear Generating Plant, have recently procured such instruments. Nevertheless, requiring the licensee to procure new instrumentation to meet the Code requirements would be a hardship because the current instrumentation should allow an adequate assessment of pump operational readiness for this pump design. Therefore, based on the determination that compliance with the Code vibration instrument low frequency response range would result in a hardship or unusual difficulty without a compensating increase in the level of quality and safety, it is recommended that the proposed alternative be authorized in accordance with 10CFR50.55a ¶(a)(3)(ii). However, when new or replacement vibration instruments are obtained in the future, these instruments should meet all the applicable Code requirements.

3. VALVE RELIEF REQUESTS

In accordance with ¶50.55a, Washington Public Power Supply System has submitted five relief requests for valves at its Nuclear Plant No. 2 (WNP-2) which are subject to inservice testing under the requirements of OMa-1988, Parts 1 and 10. These relief requests have been reviewed to verify their technical basis and their applicability. These relief requests, along with their technical evaluation by BNL, are summarized below.

3.1 Primary Containment Cooling and Purge System, Relief Request RV01

Relief Request: The licensee has requested relief from individually leak testing the drywell to suppression chamber vacuum breaker check valves, CVB-V-1AB, CD, EF, GH, JK, LM, NP, QR, ST, as required by Part 10, ¶4.2.2.

Proposed Alternate Testing: The licensee has proposed to leak test these valves according to WNP-2 Technical Specifications during refueling outages by conducting a drywell-to-suppression chamber bypass leak rate test. The licensee states that these valves are verified-closed by position indicators, tested in the open direction using a torque wrench, and each valve seat is visually inspected. Corrective actions will be as specified in the Technical Specifications. The licensee has not provided the specific Technical Specification. However, Technical Specification 4.6.2.1.d specifies the bypass leak rate test.

Licensee's Basis for Relief: The licensee states: "These check valves cannot be tested individually therefore, assigning a limiting leakage rate for each valve is not practical. The purpose of this leak rate test is to assure that the leakage from the drywell to the suppression pool chamber does not exceed Technical Specification limits. The WNP-2 Technical Specifications specify conservative corrective actions commensurate with the importance of the safety function being performed by these valves. The leakage criteria and corrective actions specified in the WNP-2 Technical Specifications is the most practical approach to assessing the adequacy of these valves in performing their specified safety function."

Evaluation: Part 10, ¶4.2.2.3 requires Category A valves, other than containment isolation valves, to be individually leak tested. Leak testing of valves in series is not allowed by the Code. The Code does, however, allow leak testing of valves in parallel, i.e., "valve combinations." Each vacuum relief valve assembly consists of two independent testable check valves in series with no instrumentation located between them to allow testing of each of the two check valves. Therefore, leak testing in

accordance with the Code is impractical. Modifications to allow individual testing of these valves would require a major system redesign and would be considered burdensome for the licensee.

These vacuum relief valve assemblies are required to be leak tight to prevent suppression pool bypass during a loss of coolant accident and open to allow non-condensibles from the wetwell to be returned to the drywell to prevent an upward pressure differential across the drywell floor after a loss of coolant accident. The Technical Specifications, 4.6.2.1.d, require a bypass leak rate test and verification that the measured leakage (i.e., the calculated $A/\sqrt{k}$ from the measured leakage) is within the specified limit every 18 months at an initial ΔP of 1.5 psi and at an initial ΔP of 5 psi every 3 years. The test schedule is dependent on successful completion of the tests. If the leakage rate exceeds the specified limit two consecutive times, the leak test shall be performed every 9 months until two consecutive acceptable leak tests. This Technical Specification leakage test complies with the requirements of ¶4.2.2.3(c) for the valve assembly. Individual valve (i.e., check valve or valve assembly) leakage limits are not specified in the Technical Specification. Although two check valves are tested in series, this leak testing combined with the proposed visual examination of the valve seats every refueling outage and stroke exercising and closure verification every 31 days should provide adequate assurance of the relief valve assembly's ability to remain leak tight and to prevent a suppression pool bypass. Therefore, it is recommended that relief from the Code requirements be granted in accordance with 10CFR50.55a ¶ (f)(6)(i), considering the burden of the licensee if the Code requirements were imposed.

3.2 Emergency Core Cooling System, Relief Request RV02

Relief Request: The licensee has requested relief from the exercising requirements of Part 10, ¶ 4.3.2 for the following water leg discharge to ECCS system check valves: LPCS-V-33, 34; HPCS-V-6, 7; and RHR-V-84A through C, 85A through C. These valves open to permit the water leg pumps to fill the RHR, HPCS, and LPCS systems and close to prevent overpressurization of the water leg pumps and associated piping.

Proposed Alternate Testing: The licensee has proposed that the stop-check and check valve will be tested in combination and verified closed (one or both) during the quarterly surveillance test. In addition, the stop-check valve will be cycled manually to ensure no binding exists. If excessive leakage is noted, both valves shall be repaired or replaced.

Licensee's Basis for Relief: The licensee states: "These valves cannot be verified to be closed without either installing a test connection or dismantling the valve and

inspecting the internals (which requires grinding out the seal weld). The associated stop-check valve is located in series with the check valve and performs the same function as the check valve. Closure of the stop-check is verified quarterly. The overpressure protection function is provided by the two valves and in addition a low pressure relief valve is installed should both the check and step-check valves fail or leak excessively.

The operability of these valves in the open direction is demonstrated continuously during normal power operation. Failure to open would become apparent by the decay of system pressure to a point where a Control Room Annunciator would turn on, indicating low system pressure."

Additionally the licensee states: "The proposed alternate testing verifies operability of the pressure isolation function shared by these valves. The required testing would be a hardship on WNP-2 with little compensating benefits. The alternate testing will provide adequate assurance of material quality and public safety."

Evaluation: There is no practical means for verifying the ability of each Category C valve in the series to close due to the lack of test connections or instrumentation. The staff in NUREG-1482, Section 4.1.1 recently provided guidance for valves such as these. As described in the NUREG, a leakage test of the valves in series may provide an acceptable means to verify valve closure provided the relief request includes information on the safety analysis's treatment of these valves, quality assurance requirements for both valves, the alternate test's acceptance criteria, and the corrective actions that would be taken if excessive leakage is identified. The licensee has provided information on the quality assurance requirements, i.e., both valves in each pair are Code Class 2 components and are included in the IST Program, and on the corrective actions that would be taken, i.e., both valves will be repaired or replaced if excessive leakage is noted. The licensee has not, however, provided a discussion of the plant safety analysis review or the acceptance criteria. The licensee should review the safety analysis report and ensure that both valves are not required to function, and revise the relief request to include this information and the acceptance criteria. Based on the impracticality of complying with the Code requirements and the burden of imposing the requirements while the licensee revises the request, i.e., requiring the licensee to perform disassembly and inspection of the valves, it is recommended that interim relief be granted in accordance with 10CFR50.55a ¶ (f)(6)(i) for one year or until the next refueling outage, whichever is later. In the interim, testing of these non-Category A check valves in series provides adequate assurance of the valves' ability to close. The licensee should revise and resubmit this request in the interim period.

3.3 Standby Service Water System, Relief Request RV03

Relief Request: The licensee has requested relief from the requirements of Part 10, ¶ 4.2.1.1 and ¶ 4.2.1.4 for exercising test frequency and power-operated valve stroke testing, respectively, for the flow control valves, SW-TCV-11A, B.

Proposed Alternate Testing: The licensee has proposed:
1) During each refueling outage perform a full calibration verification of the actuator for each of these valves per instructions provided by the valve vendor ITT General Controls Division. Each calibration verification is performed with the actuator coupled to its valve. A variable 4-20 mA test signal is applied to the actuator, and the actuator is verified to respond to stroke the valve in a linear fashion throughout its entire stroke length (i.e., from full open to full closed). Full stroke length of the valve is measured and verified that it is within acceptable range. Stroke length outside the acceptable range will indicate valve degradation requiring corrective action.

2) Concurrently with the testing described in (1) above, the fail safe position on a loss of power (OPEN) shall be verified.

Licensee's Basis for Relief: The licensee states:
"1) These hydraulically actuated valves serve as regulating thermostatic control valves. The valves do not function to rapidly isolate or de-isolate the piping into which they are installed. Rather, their function is to slowly regulate throughout their entire stroke range to control the outlet temperatures of the components they serve in response to a 4-20 mA control signal provided by their respective instrument control loops. The valves are spring-to-open/oil-to-close; recirculating oil pumps inside the actuators for the valves constantly apply a source of oil to a piston that acts against the spring. The 4-20 mA control signal varies the amount of oil constantly bled from the operating piston (back to the internal actuator reservoir). In this fashion the valves are regulated anywhere within the entire stroke length. SW-TCV-11A & 11B are controlled by thermostats which regulate main control room air temperature.

2) It is difficult to accurately measure the stroke time of these valves. These valves are not provided with any form of override that would allow them to be manually cycled. Additionally, they are not provided with position indication. Partial stroking of these valves can be verified by observing system operational parameter changes, but accurate timing of full stroke for trending purposes is impractical.

3) Manual control of these valves can only be obtained by lifting the 4-20 mA control leads to inject a test signal to the hydraulic actuator. This in turn requires that the

Technical Specification required systems they serve be taken out of service. The systems they serve are required to remain in service at all times.

4) Modification of the existing valves or installation of new valves to provide manual control and position indication would be burdensome and costly."

"The alternative testing to be performed (actuator calibration verification) will verify proper operation of the valve to meet its design function. These valves are designed to operate as slow moving regulating valves and must be able to achieve and maintain any position called for by its control instrumentation. Inability to meet the tolerances of the calibration throughout the entire range of motion will require further investigation (e.g., valve maintenance) to correct the problem to produce a satisfactory calibration check. Because the valves cannot be tested without the adverse affect of taking the associated required safety related systems out of service, testing will be at refueling outages versus quarterly. However, this form of testing is more rigorous than a quarterly stroke time test of the valves. Consequently, lengthening the time interval will not preclude timely evaluation of valve operability."

Evaluation: The subject valves are emergency chilled water hydraulically-operated control valves that regulate the control room air handling cooling coil outlet temperature. The Code requires that these fail-open control valves be stroke time tested quarterly, if practical, to monitor the valves for degrading conditions. It is impractical to measure the stroke times conventionally since these valves are not provided with position indication nor a means to allow them to be manually cycled. Manual control of these valves is only possible by lifting control leads, which requires the associated train of the standby service water system (and associated RHR loop and diesel generator) to be taken out of service per Technical Specification 3.7.1.1. It would be burdensome and would increase plant risk to perform this testing quarterly or during cold shutdowns, as these systems are required to be in service during all modes of operation. Redesigning the system to allow stroke timing of these valves would be a burden on the licensee because of the design changes that would have to be made on the control valves.

When stroke timing with conventional means is impractical, the staff in NUREG-1482, Section 4.2.9 has recommended licensees investigate other methods for monitoring degradation, including control system signal calibration. The license has proposed performing a control system calibration verification per instructions provided by the valve vendor. A test signal will be applied to the actuator and the actuator will be verified to respond in a linear fashion from full open to full close. The stroke length will be measured and verified that it is within acceptable range. The licensee has

proposed to defer this testing to refueling outages. Fail safe testing will also be performed at refueling outages. Performing the calibration and fail safe test at refueling provides reasonable assurance of the operational readiness of the valves and it is recommended that relief be granted in accordance with 10CFR50.55a ¶(f)(6)(i), considering the burden on the licensee if the Code requirements were imposed on the facility.

3.4 Post Accident Sampling System, Relief Request RV04

Relief Request: The licensee has requested relief from the requirements of Part 10, ¶ 4.2.1.4 concerning stroke time testing for the following containment isolation valves:
PSR-V-X73-1
PSR-V-X80-1
PSR-V-X83-1
PSR-V-X77A1
PSR-V-X82-1
PSR-V-X84-1
PSR-V-X77A3
PSR-V-X82-7
PSR-V-X88-1

Proposed Alternate Testing: The licensee has proposed that the stroke time of the slowest valve will be measured by terminating the stroke time measurement when the last of the nine indicating lights becomes illuminated. If the stroke time of the slowest valve is in the acceptance range, then the stroke times of all valves will be considered acceptable.

Licensee's Basis for Relief: The licensee states: "These nine PSR solenoid valves are the inboard Containment Isolation Valve for nine different penetrations and are operated from a single keylock control switch. It is impractical to measure the individual valve stroke times. To do so would require repetitive cycling of the control switch causing unnecessary wear on the valves and control switch with little compensating benefit. The proposed alternate testing will verify that the valves respond in a timely manner and provide information for monitoring signs of material degradation."

Evaluation: Part 10, ¶4.2.1.4 requires the stroke time of all power-operated valves be measured to at least the nearest second. The licensee has proposed timing only the slowest of these nine 1 inch solenoid valves, since one control switch operates all nine valves and timing each valves' stroke time would be impractical due to excessive valve wear.

The licensee states that if the slowest valve's stroking time is acceptable, then the stroke times of the remaining valves will be acceptable. However, the licensee does not state what actions will be taken if the slowest valve is unacceptable, such as considering all the valves unacceptable and taking corrective actions in accordance with ¶ 4.2.1.9 of OM-10.

Generally, small solenoid valves such as these stroke in under 2 seconds, and are considered rapid-acting valves. Ensuring that all the valves stroke in less than 2 seconds provides an equivalent level of quality and safety as the Code, since the Code only requires corrective action based on a limiting stroke time of 2 seconds, i.e., no trending of stroke times is required. Therefore, provided the licensee considers all the valves unacceptable and takes corrective action in accordance with ¶4.2.1.9, if the slowest valve is unacceptable, it is recommended that the licensee's alternative be authorized in accordance with 10CFR50.55a ¶(a)(3)(i). The licensee should revise the request to include information on the actions taken if the slowest valve is unacceptable and the rapid-acting characteristic of these valves. Additionally, the licensee should ensure that the testing method and procedure is adequate to monitor the position of all nine valves at once, as proposed.

3.5 Main Steam System, Relief Request RV05

Relief Request: The licensee has requested relief from the requirements of Part 1, ¶ 1.3.3.1(b), 3.3.1.1, and 4.1.1.4 concerning test frequency, test sequence, and temperature stability, respectively, for testing the main steam pressure relief valves (MSRV), MS-RV-1A through D, 2A through D, 3A through D, 4A through D, and 5B and C.

Proposed Alternate Testing: The licensee has proposed the following:
1. All pressure relief valves shall be as-found tested at least once every 5 years. The test interval for any individual valve (serial number) shall not exceed 5 years, with the following exceptions:

- If the valve was as-found tested immediately prior to its removal from the plant, its subsequent on-line as-found test shall be performed within 5 years from its next installation in the plant;

- If the valve was not as-found tested immediately prior to its removal from the plant and its next installation is delayed such that its previous as-found test occurred 5 or more years ago, then the as-found test on the valve after installation in the plant shall be performed during the next refueling outage.

However, the valve shall meet the post maintenance test requirements of paragraph 3.4.1.1 prior to installation.

2. a) Valves: As-found set pressure tests shall be performed on a minimum of 20% of the total population of 28 valves (or 6 valves) in any 24 months. Valves will be tracked by serial number to assure that the Code required test frequency is met.

   b) Actuators and Solenoids: The required tests shall be performed on a minimum of 20% of the total population of 18 (or 4 actuators with solenoids) in any 24 months. The actuators will be tracked by plant position to assure that each is tested within an interval not to exceed 5 years. Since the valve and actuator population sizes are different, the plant positions of the actuators selected, or due, for periodic testing may not match the plant positions of the MSRVs selected, or due, for as-found set pressure testing. The actuators/solenoids will be tested at the end of the outage after other maintenance is complete.

3. All MSRV position indicators will continue to be tested in accordance with existing surveillance procedures for monthly channel checks, and for channel calibration and channel functional testing on a refueling outage frequency. These tests will be credited for satisfying the requirements of paragraph 3.3.1.1(g) of this Part.

4. All auxiliary actuating device sensing elements (pressure switches) will continue to be tested and calibrated on a 24 month frequency during shutdowns. These tests will be credited for satisfying the requirements of paragraph 3.3.1.1(i) of this Part.

5. For on-line set pressure testing of MSRVs, a minimum of four hours soak time at nominal system operating conditions (greater than 862 psig) will be required prior to commencing testing to allow valve temperatures to stabilize; there will be no direct measurement of valve body temperature to indicate stabilization.

Licensee's Basis for Relief: The license states the following:
"1. MSRV periodic set pressure testing is performed on-line. Removal and replacement of the MSRVs is used only for valve maintenance and not for the purpose of as found set pressure determination. With 18 installed MSRV positions in the plant, and a total of 28 individual valves that can be used in those positions (provided valve set pressure matches the required set pressure for the position), it is impractical to perform on-line as found set pressure testing on each of the 28 valves in each 5 year period. Some valves may be installed for only one or two consecutive years in the 5 year period while others may not be installed at all during the period. Changing from testing all valves in each subsequent 5 year period to testing individual valves every 5

years is consistent with OMc Code-1994 Appendix I, paragraph I 1.3.3(a). Valves removed for maintenance will be set pressure tested, either on-line or bench test, prior to return to service.

2. "Valves" and "accessories" (actuators, solenoids, etc.) have different population sizes due to the methods used for maintenance and testing at WNP-2 and should be considered separately for the purposes of meeting the required test frequency and testing requirements. Actuators and solenoids remain in place when MSRVs are removed for maintenance. Therefore, the total population of MSRVs is 28 valves which includes spare valves which may be installed at some time during the 5 year period, whereas the total population of accessories is 18 since they are not removed with the valves.

Testing the accessories (actuators, solenoids, etc.) after maintenance or set pressure adjustment is complete is consistent with OMc Code-1994 Appendix I, paragraph 1.3.3.1.

3. Part 1 requires testing of accessories in a prescribed sequence. Paragraph 3.3.1.1(g) requires determination of operation and electrical characteristics of position indicators, and paragraph 3.3.1.1(i) requires determination of actuating pressure of auxiliary actuating device sensing element and electrical continuity. These tests are required to be performed at the same frequency as the valve set pressure and auxiliary actuating device testing.

The position indicators are all calibrated and functional tested at refueling outages; the sensing elements (pressure switches) are all checked and calibrated normally every 24 months. Although the existing tests are not in the prescribed sequence, and they do not have a one-to-one correspondence to the valve or actuator tests, these calibrations and functional tests meet all testing requirements of this Part, and far exceed the required test frequency and testing requirements.

4. MSRV set pressure testing is performed on-line. There are no permanently installed temperature sensors mounted on the installed valve bodies to measure valve body temperature. When on-line testing is performed, the valves are mounted on the steam lines and the plant and drywell are at normal operating temperature and pressure conditions. For on-line tests, the plant has been at operating conditions for an extended period of time, or has undergone a slow heat-up to low power, and both valve and ambient drywell temperatures are at, or near, their normal operating conditions. In addition, the on-line set pressure test procedure requires that the system be held at nominal operating temperature and pressure for a minimum of four

hours soak time prior to commencing testing to allow the valve temperature to stabilize."

Additionally, the licensee states: "Due to different population sizes of valves and accessories and also due to methods used for testing and maintenance, it is impractical to meet the Code required testing requirements without subjecting the valves to unnecessary challenges. The requirement for testing actuators and accessories in a specific sequence does not enhance system or component operability, or in any way improve nuclear safety. Installation of remote temperature sensing instrumentation to comply with Part 1 requirement will be undue hardship for WNP-2. Four hour soak time prior to commencing testing provides adequate assurance that temperature stability is achieved prior to as-found testing. The proposed alternate testing adequately evaluates the operational readiness of these valves commensurate with their safety function. This will help reduce the number of challenges and failures of safety relief valves and still provide timely information regarding operability and degradation. This will provide adequate assurance of material quality and public safety."

Evaluation: A number of clarifications to the requirements for testing pressure relief devices have been made in the 1994 Addenda to the OM Code, Appendix I. As discussed in NUREG-1482, Section 4.3.9, NRC approval is not required to use these clarifications, however, they should be documented in the IST Program.

OM-1987, Part 1, ¶1.3.3.1 requires all Class 1 pressure relief valves of each type and manufacture to be tested within a 5 year period, with a minimum of 20% of the valves tested within any 24 months. This 20% shall be previously untested valves, if they exist. The 1994 Addenda of the OM Code, ¶1.3.3(a) provides clarification that each Class 1 pressure relief valve is required to be tested every 5 years; that there is no specified maximum number of valves to be tested each 24 month interval, only the minimum (i.e., 20%); and that the test interval for any individual valve shall not exceed 5 years. The licensee has proposed as-found testing the MSRVs at least once every 5 years, with the test interval for any individual valve (serial number) not to exceed 5 years. The licensee has, however, provided two exceptions to this test frequency, regarding valves that are removed from the plant. Valves that were tested immediately prior to removal from the plant, will be subsequently tested on-line within 5 years from their next installation in the plant. Additionally, valves that were not immediately tested prior to removal, and their installation is delayed such that their previous test occurred 5 or more years ago, will be tested during the next refueling outage after reinstallation. The OM Code does not specifically address the test interval of valves that are swapped from storage and the licensee has not provided a basis for these exceptions. The Code does not require periodic on-line testing; testing

on the bench is also acceptable. The licensee has stated in the basis that valves that are removed for maintenance will be set pressure tested, either on-line or bench test, prior to return to service. Therefore, it appears that the licensee can perform testing of all valves, including those removed, at least once every 5 years either on-line or by bench testing. The licensee should revise the request to clarify that the 1994 Addenda testing frequency requirements will be complied with. Relief to use this clarification, as discussed above, is not required.

In addition the licensee has proposed testing the valves and actuators/solenoids on a different schedule based on the smaller population of actuators (18) to valves (24). The licensee has also proposed performing the determination of operation and electrical characteristics of position indicators and determination of actuating pressure of auxiliary actuating device sensing element and electrical continuity, independent of testing the valves or actuators. The licensee proposes to perform these tests at refueling or every 2 years, respectively. The OM Code and Standard do not address testing actuators or accessories independent of the valves, but require tests of the valve and its accessories to be performed in a specific sequence (¶3.3.1.1) every 5 years. The OM Code committee, however, has recently approved a revision to Appendix I that would remove the requirement to perform the accessories and seat tightness tests (3.3.1.1(d)-(i)) in a specific sequence (ROM 95-03). There was no technical basis for requiring the specific sequence. The new revision still requires these tests to be performed following the visual exam, seat tightness determination, set pressure determination, and any maintenance or set pressure adjustments. No maintenance or set pressure adjustment is allowed prior to the visual exam, seat tightness determination, set pressure determination. The visual exam may be performed out of sequence when performing on-line periodic testing (included in the 1994 Addenda). Testing the actuators and solenoids and performing the determination of operation and electrical characteristics of position indicators and determination of actuating pressure of auxiliary actuating device sensing element and electrical continuity, independent and on a different schedule than the valves may be acceptable if no maintenance or adjustments are made that could affect the valve's future set pressure determination. The licensee must address this procedurally.

Provided that the licensee ensures that no maintenance or set-pressure adjustments are made prior to the set pressure determination, the licensee's proposal for position indicators and pressure switches should provide an equivalent or higher level of quality and safety based on the increased test interval for the position indicators and pressure switches, it is recommended that the alternate be approved in accordance with 10 CFR 50.55a ¶ (a)(3)(i). If the licensee determines that the once every 5 years frequency of testing discussed in item 1 above cannot be complied with, a revised submittal should be made providing justification for a different frequency.

The licensee has also proposed using another clarification contained in the 1994 Addenda of the OM Code, concerning thermal equilibrium. OM-1987, Part 1, ¶4.1.1.4 requires that the temperature of the valve body be known and stabilized before commencing set pressure testing, with no change in measured temperature of more than 10 F in 30 minutes. The 1994 Addenda provided additional clarification that verification of thermal equilibrium is not required for valves which are tested at ambient temperature using a test medium at ambient temperature (¶l 4.1.1(d)). Ambient temperature is defined in ¶l 1.2 to be the temperature of the environment surrounding the relief valve at its installed plant location during the phase of plant operation for which the valve is required for overpressure protection. The licensee proposal complies with this clarification and, per the NUREG, NRC approval is not required.

4. IST PROGRAM RECOMMENDED ACTION ITEMS

Inconsistencies, omissions, and required licensee actions identified during the review of the licensee's second 10 year interval Inservice Testing Program relief requests are summarized below. The licensee should resolve these items in accordance with the evaluations presented in this report.

4.1 The licensee infers that measuring discharge pressure is more conservative for the standby service water pumps, SW-P-1A, -1B, and HPCS service water pump, HPCS-P-2, because the measurement is uncorrected for elevation. It is assumed that the bay level is at a lower elevation than the discharge piping, thus the discharge pressure is smaller than the pump differential simply because of the difference in static head. It is recommended that the licensee's proposal in Relief Request RP01 be authorized pursuant to 10CFR50.55a ¶ (a)(3)(i), provided that the discharge pressure is less than the calculated differential pressure considering the entire range of suction pressures, such that the acceptance criteria assigned to the discharge pressure gives equivalent protection provided by the Code for differential pressure. (TER Section 2.1.1)

4.2 The licensee has proposed in Relief Request RP02 to calculate the flowrates of the diesel fuel oil transfer pumps based on a change in tank level over time and in Relief Request RP06 to calculate the suction pressure based on tank level. The licensee should ensure that the calculational methods are properly proceduralized and meet quality assurance requirements. (TER Section 2.2)

4.3 It is recommended that the licensee be authorized to use existing discharge pressure instrumentation for the RHR and High Pressure Core Spray pumps (Relief Request RP05) and vibration instrumentation for the SLC pumps (Relief Request RP07). In the event these instruments are replaced, the licensee should install instruments which meet all the Code requirements. (TER Sections 2.3.2 and 2.4)

4.4 As described in NUREG-1482, a leakage test of valves in series may provide an acceptable means to verify valve closure provided the relief request includes information on the safety analysis treatment of these valves, quality assurance requirements for both valves, the alternate test's acceptance criteria, and the corrective actions that would be taken if excessive leakage is identified. The licensee has not provided a discussion of the plant safety analysis review or the acceptance criteria for the RHR, LPCS and HPCS water leg check valves (Relief Request RV02). The licensee should review the safety analysis report and

ensure that both valves are not required to function, and revise the relief request to include this information and the acceptance criteria. It is recommended that interim relief be granted in accordance with 10CFR50.55a ¶ (f)(6)(i) for one year or until the next refueling outage, whichever is later. The licensee should revise and resubmit this request in the interim period. (TER Section 3.2)

4.5 The licensee states that if the slowest Post Accident Sampling System valve's stroke time is acceptable, then the stroke times of the remaining valves will be acceptable (Relief Request RV04). However, the licensee does not state what actions will be taken if the slowest valve is unacceptable. It is recommended that the licensee's alternative be authorized provided the licensee considers all the valves unacceptable and takes corrective action in accordance with ¶4.2.1.9, if the slowest valve is unacceptable. The licensee should revise the request to include information on the actions taken if the slowest valve is unacceptable and the rapid-acting characteristic of these valves. Additionally, the licensee should ensure that the testing method and procedure is adequate to monitor the position of all nine valves at once, as proposed. (TER Section 3.4)

4.6 The licensee should revise the IST Program (Relief Request VR05) to clarify that the 1994 Addenda testing frequency requirements will be complied with (i.e., that the valves will be as-found or bench tested every 5 years). Relief to use this clarification, as discussed in TER Section 3.5 is not required.

Testing the MSRV actuators and solenoids and performing the determination of operation and electrical characteristics of position indicators and determination of actuating pressure of auxiliary actuating device sensing element and electrical continuity, independent and on a different schedule than the valves may be acceptable if no maintenance or adjustments are made that could affect the valve's future set pressure determination. The licensee must address this procedurally. It is recommended that the alternate be approved, provided that the licensee ensures that no maintenance or set-pressure adjustments are made prior to the set pressure determination.

4.7 The licensee should verify the correctness of the flow diagram coordinates specified in the Pump Inservice Test Table. For example, the coordinates provided for the diesel transfer pumps for Flow Diagrams M512-1 and -4 are incorrect.

5. REFERENCES

1. Letter GO2-94-280, "Submittal of the Second Ten-Year Interval Pump and Valve Inservice Testing (IST) Program Plan", J. V. Parrish to USNRC, December 16, 1994.

2. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection", 1989 Edition.

3. ASME/ANSI OMa-1988, Part 1, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices."

4. ASME/ANSI OMa-1988, Part 6, "Inservice Testing of Pumps in Light-Water Reactor Power Plants."

5. ASME/ANSI OMa-1988, Part 10, "Inservice Testing of Valves in Light-Water Reactor Power Plants."

6. Title 10, Code of Federal Regulations, Section (§) 50.55a, Codes and Standards.

7. Standard Review Plan, NUREG-0800, Section 3.9.6, "Inservice Testing of Pumps and Valves," Rev. 2, July 1992.

8. NRC Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," April 3, 1989.

9. Minutes of the Public Meetings on Generic Letter 89-04, October 25, 1989.

10. Supplement to the Minutes of the Public Meetings on Generic Letter 89-04, September 26, 1991.

11. NRC Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," Supplement 1, which includes NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," P. Campbell, April 1995.

12. ASME Code for Operation and Maintenance of Nuclear Power Plants, 1990 Edition including the 1992 and 1994 Addenda.

WASHINGTON NUCLEAR PLANT NO. 2

ANNUAL OPERATING REPORT

1995

DOCKET NO. 50-397

FACILITY OPERATING LICENSE NO. NPF-21

Washington Public Power Supply System
3000 George Washington Way
Richland, Washington 99352

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1.0 INTRODUCTION

The 1995 Annual Operating Report of Washington Public Power Supply System Plant Number 2 (WNP-2) is submitted pursuant to the requirements of Federal Regulations and Facility Operating License NPF-21. Plant WNP-2 is a 3486 MWt, BWR-5, which began operation on December 13, 1984.

Except for short downpower evolutions for periodic testing and routine maintenance, the plant had been operating at or near full power for 203 consecutive days until February 18, 1995 when an automatic scram occurred due to operator error during monthly main turbine governor valve testing. On February 26, 1995 an automatic scram occurred due to the failure of a Digital Electro-Hydraulic System control card. Following startup from the scram, the plant operated at or near full power until April 5, 1995 when an automatic scram and turbine trip occurred during surveillance testing due to a protective system relay failure. Following a six-day forced outage, the plant operated at or near full power until it was manually shutdown on April 22, 1995 to officially enter the 1995 Maintenance and Refueling Outage (R-10).

The plant ended the annual maintenance and refueling outage and on June 9, 1995 was placed on reserve shutdown following one-half day of turbine testing on the grid. The plant continued in a reserve shutdown status until commencement of startup and synchronization to the electrical grid on July 3, 1995. The plant then remained on-line for the duration of the year. The Bonneville Power Administration, customer for WNP-2 electricity, on several occasions throughout the year requested that WNP-2 reduce power levels so that the federal power marketing agency could maximize its generating capability from the region's hydroelectric projects. This was due to circumstances involving unusually warm, wet weather conditions in the region.

During 1995 there were numerous examples of major accomplishments which required significant effort on the part of Supply System personnel to complete. The following is a summary of those efforts.

The tenth refueling outage was successfully completed in 49 days. Significant planned and emergent activities included:

- Reactor Power Uprate modification and implementation.
- Replacement of 152 fuel assemblies.
- Reactor vessel piping nozzle flushing (cleaning).
- Reactor core shroud head bolt replacement (36 bolts).
- Replacement of 12 Local Power Range Monitors.

- In-vessel In-Service Inspection (ISI) including core shroud measurements, dry instrument (neutron monitor) tube inspections, and jet pump inspections.
- Six-year period maintenance on the High Pressure Core Spray System Diesel Generator.
- Chemical cleaning of High Pressure Core Spray System piping.
- Replacement of the High Pressure Core Spray System battery and enclosure.
- Reactor Water Cleanup (RWCU) System chemical decontamination.
- High pressure turbine inspection.
- RWCU high energy line break modification.
- Reactor Building stack monitor modification.
- Containment exhaust and supply purge valve replacement.
- Random sample testing of 37 piping snubbers (zero failures).

In calendar year 1995, the actual power generation of WNP-2 was 6,933,184 net megawatt-hours which was second only to the 7.1 million megawatt-hours generated in 1993. By including economic dispatch (load-following downpower) credit from the Bonneville Power Administration, WNP-2 generation in 1995 would have been 7,836,888 net megawatt-hours, which would have been the best on record.

In addition to increased electrical generation, improvements in the overall reliability of WNP-2 were evident in the achievement of an 80 percent capability factor, up from 72.3 percent for 1994.

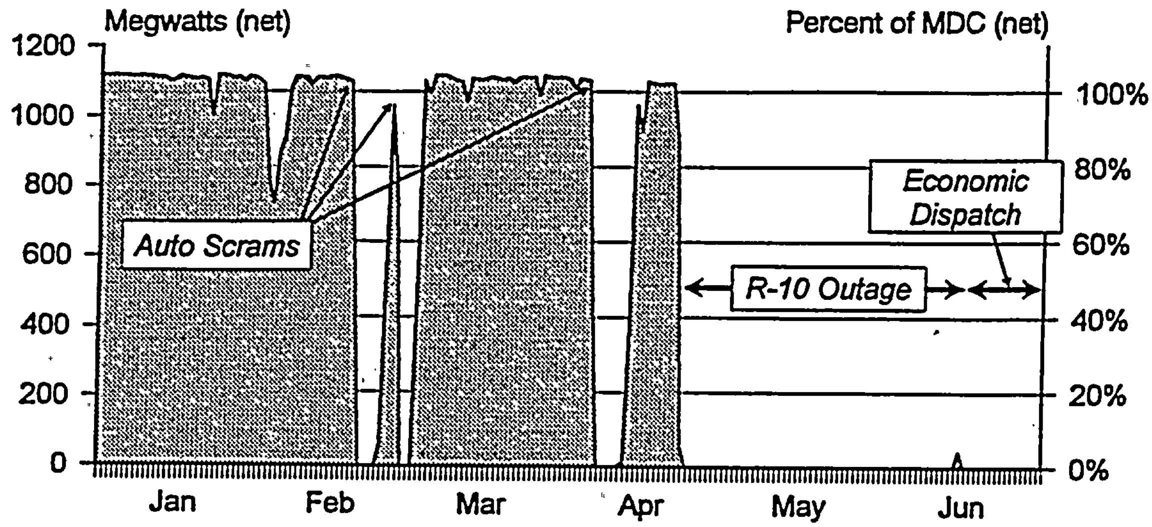
Other highlights during 1995 included the exemplary performance of the Supply System response team during the annual emergency exercise; a 25 percent reduction in radiation exposure for employees over the previous year; and the requalification of the plant's 52 licensed reactor operators.

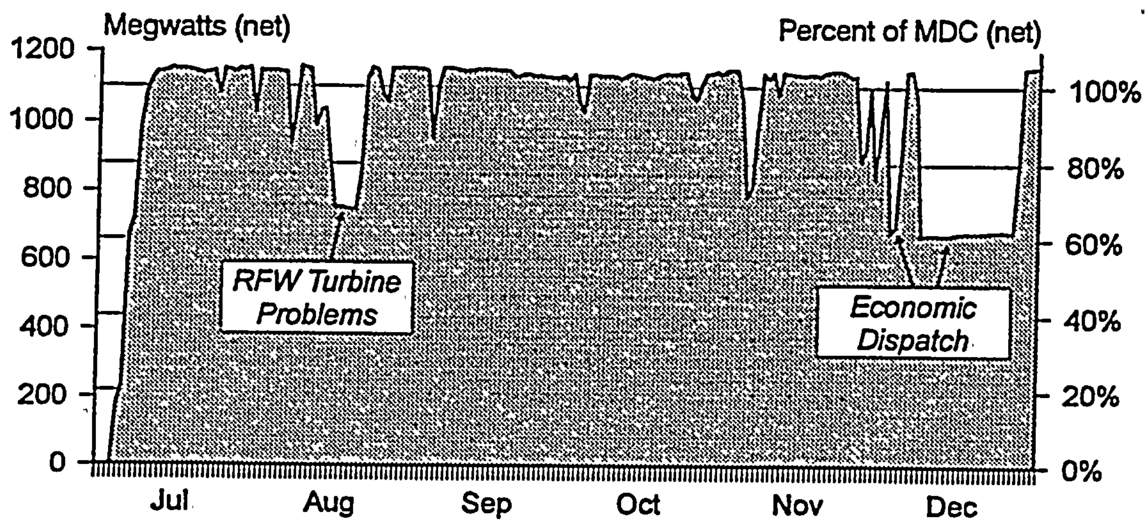
The 1995 capacity factors, based on net electrical energy output are listed below.

Month	Capacity Factor
January	102.1
February	68.1
March	96.5
April*	44.8
May	0
June**	0
July	85.7
August	94.5
September	103.1
October	102.3
November	97.8
December	73.8
Overall	72.5

* Started Maintenance and Refueling Outage
** Ended Maintenance and Refueling Outage

1.1 WNP-2 LOAD PROFILE FOR 1995

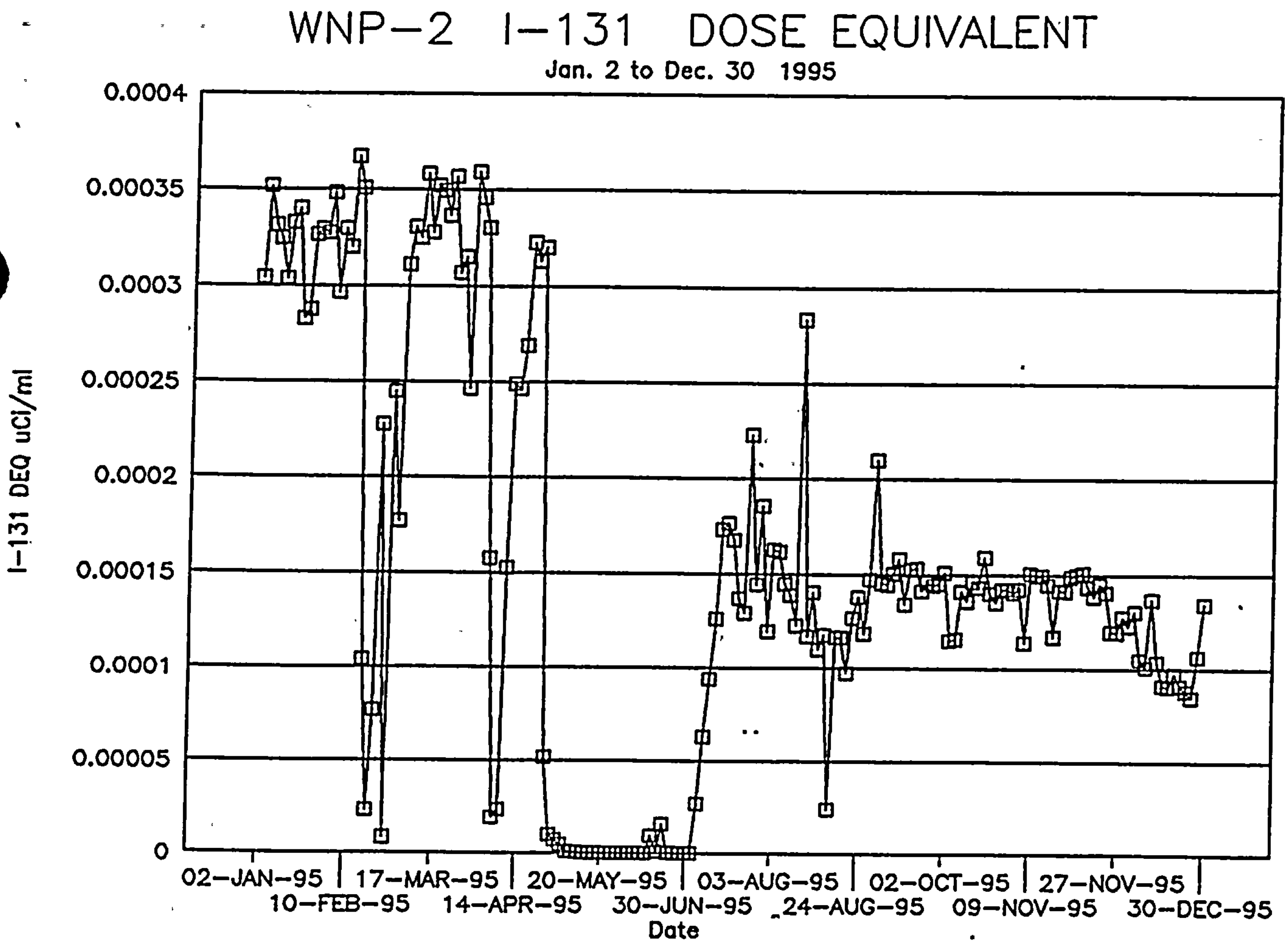




1.2 REACTOR COOLANT SPECIFIC ACTIVITY LEVELS

This section contains information relative to reactor coolant cumulative iodine levels, iodine spikes and specific activity of all isotopes other than iodine, and is reported in accordance with Technical Specification paragraph 6.9.1.5.c.

The specific activity of the primary coolant was significantly less than 0.2 microcuries per gram dose equivalent I-131 as set forth in WNP-2 Technical Specification LCO 3/4.4.5. In addition, the specific activity of the primary coolant was routinely sampled and was, in all cases, less than 100/E-bar microcuries per gram.



2.0 REPORTS

The reports provided in this section meet the requirements of Federal Regulations and the WNP-2 Operating License. They cover the requirements of the WNP-2 Technical Specifications, Sections 6.9.1.4 and 6.9.1.5 and provide the information specified by Regulatory Guide 1.16, "Reporting of Operating Information." In addition, Section 2.6 provides the information required by 10CFR50.59, "Changes, Tests, and Experiments."

2.1 ANNUAL PERSONNEL EXPOSURE AND MONITORING REPORT

The information provided in this section of the report is required by the WNP-2 Technical Specifications, Section 6.9.1.5a, and Regulatory Guide 1.16, Revision 4. These values are estimated doses for the listed activities based on direct dosimeter data. No correction has been applied to these readings.

10 CFR PART 20

Facility: 02

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
RADIATION EXPOSURE RECORDS
WORK AND JOB FUNCTION REPORT

Report for Calendar Year: 1995

This report was produced with direct reading dosimeter data

Number of Persons Receiving Over 100 millirem is 889 Total MAN-REM: 399.460

		----Number of Individuals---			-----Year to Date Dose-----		
		Station Employees	Utility Employees	Contractors and Others	Station Employees	Utility Employees	Contractors and Others
OPERATIONS AND SURVEILLANCE	Maintenance Personnel	93.18	4.95	47.64	23.832	1.618	5.769
	Operating Personnel	46.57	1.1	1	22.834	0.229	0.193
	Health Physics Personnel	35.23	0.75	34.96	9.569	0.057	5.195
	Supervisory Personnel	14.14	3.73	1.66	2.891	0.539	0.273
	Engineering Personnel	11.37	20.41	11.25	1.411	3.262	0.875
ROUTINE MAINTENANCE	Maintenance Personnel	97.62	2.69	240.85	68.152	2.507	109.11
	Operating Personnel	2.25	0.01	0	8.038	0.026	0
	Health Physics Personnel	5.66	0.14	21.43	11.087	0.048	13.495
	Supervisory Personnel	4.32	1.94	4.79	3.715	0.518	1.009
	Engineering Personnel	7.86	12.73	31.46	4.027	7.029	9.146
INSERVICE INSPECTION	Maintenance Personnel	0.4	0	34.61	0.582	0.004	18.944
	Operating Personnel	0	0	0	0.002	0	0
	Health Physics Personnel	0.14	0	0.13	0.232	0	0.187
	Supervisory Personnel	0	0	0.59	0	0	0.384
		1.98	1.53	15.57	1.027	2.512	10.139
SPECIAL MAINTENANCE	Maintenance Personnel	0	0	0	0	0	0
	Operating Personnel	0	0	0	0	0	0
	Health Physics Personnel	0	0	0	0	0	0
	Supervisory Personnel	0	0	0	0	0	0
	Engineering Personnel	0	0	0	0	0	0
WASTE PROCESSING	Maintenance Personnel	0.38	0.22	0.18	0.949	0.458	0.017
	Operating Personnel	0.01	0	0	0.01	0	0
	Health Physics Personnel	0.53	0	3.51	0.578	0	1.98
	Supervisory Personnel	0.01	0	0	0.071	0	0
	Engineering Personnel	0.05	0.13	0	0.004	0.013	0
REFUELING	Maintenance Personnel	15.13	0.07	14.39	20.71	0.02	6.423
	Operating Personnel	2.06	0	0	1.934	0	0
	Health Physics Personnel	1.36	0	13.92	0.609	0	4.964
	Supervisory Personnel	2.31	0.4	0.96	2.188	0.15	0.109
	Engineering Personnel	2.18	3.71	5.41	0.557	0.999	1.346
TOTAL	Maintenance Personnel	206.71	7.93	337.67	114.225	4.607	140.263
	Operating Personnel	50.89	1.11	1	32.818	0.255	0.193
	Health Physics Personnel	42.92	0.89	73.95	22.075	0.105	25.821
	Supervisory Personnel	20.78	6.07	8	8.865	1.207	1.775
	Engineering Personnel	23.44	38.51	63.69	7.026	13.815	21.506
Grand Total		344.74	54.51	484.31	185.009	19.989	189.558

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

This section contains information pertaining to main steam line safety/relief valve challenges for calendar year 1995 in accordance with the requirements of WNP-2 Technical Specification 6.9.1.5(b).

The main steam line safety/relief valve challenges (actuation events) are shown on the following tables. The data includes all in-situ tests. For ease of reference, the following descriptive codes are used for each actuation or failure to actuate:

1. Type of Actuation

   A = Automatic
   B = Remote Manual
   C = Spring

2. Cause/Reason for Actuation

   A = Overpressure
   B = ADS or other safety
   C = Test
   D = Inadvertent (Accidental/Spurious)
   E = Manual relief

3. Reactor Operating Condition Prior to Lift

   A = Construction
   B = Preoperational, startup or power ascension tests in progress
   C = Routine startup
   D = Routine shutdown
   E = Steady state operations
   F = Load changes during routine operation
   G = Shutdown (hot or cold), except refueling
   H = Refueling

4. Failures and Reports

   A = Failure of electrical or other components not considered part of the valve assembly - No SRVS failure report required
   B = Failure of any part of the valve - SRVS failure report will be filed
   C = No failures occurred - No SRVS failure report required
   D = LER Submitted - Report LER number in Item 316
   E = NPRDS will be submitted

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0120	63790-00-0120	63790-00-0046		
Component ID (Location)	MS-RV-1B	MS-RV-1B	MS-RV-1C		
Date of Actuation (Mo/Da/Yr)	2/18/95	2/26/95	2/26/95		
Time of Day (24 Hour Clock)	1228	1739	1739		
Type of Actuation (Code)	A	A	A		
Cause/Reason for Actuation (Code)	A	A	A		
Rx Operating Condition Prior to Lift (Code)	B	B	B		
Rx Power Level Prior to Lift (% Rated Thermal)	100	100	100		
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A		
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer		
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN		
Rx Pressure Prior to Actuation (PSIG)	1034	1064	1068		
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A		
Duration of This Actuation (Minutes, Seconds)	13 Sec.	13 Sec.	9 Sec.		
Failures, Reports (Code)	A	C	C		
LER Number (5 Digit Number)	N/A	N/A	N/A		

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0048	63790-00-0120	63790-00-0046	63790-00-0122	63790-00-0122
Component ID (Location)	MS-RV-1A	MS-RV-1B	MS-RV-1C	MS-RV-2C	MS-RV-2C
Date of Actuation (Mo/Da/Yr)	4/5/95	4/5/95	4/5/95	4/5/95	4/22/95
Time of Day (24 Hour Clock)	0957	0957	0957	0957	1338
Type of Actuation (Code)	A	A	A	A	C
Cause/Reason for Actuation (Code)	A	A	A	A	C
Rx Operating Condition Prior to Lift (Code)	E	E	E	E	D
Rx Power Level Prior to Lift (% Rated Thermal)	100	100	100	100	15
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	1078	1061	1078	1078	928
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	8 SEC.	13 SEC.	8 SEC.	7 SEC.	6 SEC.
Failures, Reports (Code)	C	A	C	C	A
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0051	63790-00-0052	63790-00-0055	63790-00-0134	63790-00-0138
Component ID (Location)	MS-RV-2A	MS-RV-3C	MS-RV-4C	MS-RV-2B	MS-RV-2D
Date of Actuation (Mo/Da/Yr)	4/22/95	4/22/95	4/22/95	4/22/95	4/22/95
Time of Day (24 Hour Clock)	1338	1338	1338	1338	1338
Type of Actuation (Code)	C	C	C	C	C
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	D	D	D	D	D
Rx Power Level Prior to Lift (% Rated Thermal)	15	15	15	15	15
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	928	928	928	928	928
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	6 SEC.	4 SEC.	4 SEC.	4 SEC.
Failures, Reports (Code)	A	A	A	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0046	63790-00-0048	63790-00-0047	63790-00-0057	63790-00-0054
Component ID (Location)	MS-RV-1C	MS-RV-1A	MS-RV-1D	MS-RV-3A	MS-RV-2A
Date of Actuation (Mo/Da/Yr)	4/22/95	4/22/95	4/22/95	4/22/95	5/26/95
Time of Day (24 Hour Clock)	1338	1338	1338	1338	1500
Type of Actuation (Code)	C	C	C	C	B
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	D	D	D	D	G
Rx Power Level Prior to Lift (% Rated Thermal)	15	15	15	15	0
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	928	928	928	928	0
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	4 SEC.	4 SEC.	4 SEC.	5 MIN.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0058	63790-00-0124	63790-00-0056	63790-00-0139	63790-00-0122
Component ID (Location)	MS-RV-3A	MS-RV-3C	MS-RV-4C	MS-RV-1C	MS-RV-2C
Date of Actuation (Mo/Da/Yr)	5/26/95	5/26/95	5/26/95	5/26/95	5/26/95
Time of Day (24 Hour Clock)	1500	1500	1500	1500	1500
Type of Actuation (Code)	B	B	B	B	B
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	G	G	G	G	G
Rx Power Level Prior to Lift (% Rated Thermal)	0	0	0	0	0
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	0	0	0	0	0
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	5 MIN.	5 MIN.	5 MIN.	5 MIN.	5 MIN.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0138	63790-00-0050	63790-00-0049	63790-00-0140	63790-00-0134
Component ID (Location)	MS-RV-2D	MS-RV-2B	MS-RV-1A	MS-RV-1B	MS-RV-1D
Date of Actuation (Mo/Da/Yr)	5/26/95	5/26/95	5/26/95	5/26/95	5/26/95
Time of Day (24 Hour Clock)	1500	1500	1500	1500	1500
Type of Actuation (Code)	B	B	B	B	B
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	G	G	G	G	G
Rx Power Level Prior to Lift (% Rated Thermal)	0	0	0	0	0
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	0	0	0	0	0
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	5 MIN.	5 MIN.	5 MIN.	5 MIN.	5 MIN.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0049	63790-00-0054	63790-00-0058	63790-00-0135	63790-00-0140
Component ID (Location)	MS-RV-1A	MS-RV-2A	MS-RV-3A	MS-RV-4A	MS-RV-1B
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95	6/12/95	6/12/95	6/12/95
Time of Day (24 Hour Clock)	1735	1735	1652	1652	1735
Type of Actuation (Code)	C	C	C	C	C
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	C	C	C	C	C
Rx Power Level Prior to Lift (% Rated Thermal)	10	10	10	10	10
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	921	921	921	921	921
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	4 SEC.	4 SEC.	4 SEC.	4 SEC.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0050	63790-00-0053	63790-00-0137	63790-00-0136	63790-00-0139
Component ID (Location)	MS-RV-2B	MS-RV-3B	MS-RV-4B	MS-RV-5B	MS-RV-1C
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95	6/12/95	6/12/95	6/12/95
Time of Day (24 Hour Clock)	1735	1735	1652	1652	1735
Type of Actuation (Code)	C	C	C	C	C
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	C	C	C	C	C
Rx Power Level Prior to Lift (% Rated Thermal)	10	10	10	10	10
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	921	921	921	921	921
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	4 SEC.	4 SEC.	4 SEC.	4 SEC.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0122	63790-00-0062	63790-00-0134	63790-00-0138	63790-00-0126
Component ID (Location)	MS-RV-2C	MS-RV-5C	MS-RV-1D	MS-RV-2D	MS-RV-3D
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95	6/12/95	6/12/95	6/12/95
Time of Day (24 Hour Clock)	1735	1652	1735	1735	1652
Type of Actuation (Code)	C	C	C	C	C
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	C	C	C	C	C
Rx Power Level Prior to Lift (% Rated Thermal)	10	10	10	10	10
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	921	921	921	921	921
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	4 SEC.	4 SEC.	4 SEC.	4 SEC.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0135	63790-00-0137	63790-00-0056	63790-00-0126	63790-00-0136
Component ID (Location)	MS-RV-4A	MS-RV-4B	MS-RV-4C	MS-RV-3D	MS-RV-5B
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95	6/12/95	6/12/95	6/12/95
Time of Day (24 Hour Clock)	2110	2112	2114	2128	2129
Type of Actuation (Code)	B	B	B	B	B
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	C	C	C	C	C
Rx Power Level Prior to Lift (% Rated Thermal)	15	15	15	15	15
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	915	915	915	915	915
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	42 SEC.	38 SEC.	37 SEC.	39 SEC.	42 SEC.
Failures, Reports (Code)	C	C	C	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0060	63790-00-0124	63790-00-0056	63790-00-0124	63790-00-0056
Component ID (Location)	MS-RV-4D	MS-RV-3C	MS-RV-4C	MS-RV-3C	MS-RV-4C
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95	6/12/95	7/3/95	7/3/95
Time of Day (24 Hour Clock)	1652	1652	1652	0259	0259
Type of Actuation (Code)	C	C	C	C	C
Cause/Reason for Actuation (Code)	C	C	C	C	C
Rx Operating Condition Prior to Lift (Code)	C	C	C	C	C
Rx Power Level Prior to Lift (% Rated Thermal)	10	10	10	10	10
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A	N/A	N/A	N/A
Other Instrumentation Type (Code)	Process Computer	Process Computer	Process Computer	Process Computer	Process Computer
Other Instrumentation Number Reading and Units	OPEN	OPEN	OPEN	OPEN	OPEN
Rx Pressure Prior to Actuation (PSIG)	921	921	921	923	923
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A	N/A	N/A	N/A
Duration of This Actuation (Minutes, Seconds)	4 SEC.	20 SEC.	8 SEC.	4 SEC.	4 SEC.
Failures, Reports (Code)	C	A	A	C	C
LER Number (5 Digit Number)	N/A	N/A	N/A	N/A	N/A

2.2 MAIN STEAM LINE SAFETY/RELIEF VALVE CHALLENGES

For Each Actuation or Failure to Actuate:	1	2	3	4	5
S/R Valve Serial Number	63790-00-0062	63790-00-0060			
Component ID (Location)	MS-RV-5C	MS-RV-4D			
Date of Actuation (Mo/Da/Yr)	6/12/95	6/12/95			
Time of Day (24 Hour Clock)	2131	2244			
Type of Actuation (Code)	B	B			
Cause/Reason for Actuation (Code)	C	C			
Rx Operating Condition Prior to Lift (Code)	C	C			
Rx Power Level Prior to Lift (% Rated Thermal)	15	15			
Time Req'd for Tailpipe Temp to Return to Normal	N/A	N/A			
Other Instrumentation Type (Code)	Process Computer	Process Computer			
Other Instrumentation Number Reading and Units	OPEN	OPEN			
Rx Pressure Prior to Actuation (PSIG)	915	915			
IF AVAILABLE/IF APPLICABLE					
Reseat Pressure At Valve Closure (PSIG)	N/A	N/A			
Duration of This Actuation (Minutes, Seconds)	36 SEC.	23 SEC.			
Failures, Reports (Code)	C	C			
LER Number (5 Digit Number)	N/A	N/A			

2.3 SUMMARY OF PLANT OPERATIONS

This report section is included in accordance with the guidance in Regulatory Guide 1.16 (C.1.b)

January 1995

- Except for short downpower evolutions for periodic testing and minor maintenance, the plant operated at or near full power during the month.

February 1995

- The plant was downpowered on February 1, 1995 for changeout of condensate filter/demineralizer septa to correct a high sulfate condition in the reactor water.
- On February 18, 1995 the plant experienced an automatic scram due to operator error during monthly main turbine governor valve testing. The scram occurred when Operations personnel actuated a turbine trip reset lever instead of the adjacent turbine trip test lever.
- On February 26, 1995 the plant experienced an automatic scram due to a Digital Electro-Hydraulic (DEH) System control card malfunction which caused the closure of the turbine governor valves. The control card was replaced and no further problems were noted.

March 1995

- Following startup from the automatic scram caused by the DEH control panel problem, the plant operated at or near full power during the remainder of the month.

April 1995

- The plant operated at or near full power until April 5, 1995 when an automatic scram and turbine trip occurred during surveillance testing due to a protective system relay failure. The purpose of the surveillance test was to verify operability of the high reactor water level turbine trip feature. The relay was replaced and no further problems were noted.
- Following a six-day forced outage, the plant was restarted and operated at or near full power until it was shutdown on April 22, 1995 for the annual maintenance and refueling outage.

May 1995

- The plant was in the annual maintenance and refueling outage for the entire month.

June 1995

- The plant ended the annual maintenance and refueling outage and on June 9, 1995 was placed on reserve shutdown following one-half day of turbine testing on the grid.

July 1995

- The plant continued in a reserve shutdown status until commencement of startup and synchronization to the electrical grid on July 3, 1995. Except for short downpower evolutions for periodic testing and minor maintenance, the plant operated at or near full power during the remainder of the month.

- A new full power level increase of five percent was confirmed as a result of the reactor power uprate modification that was implemented during the maintenance and refueling outage.

August 1995

- The plant operated at full power until August 6, 1995 when it was downpowered to troubleshoot main turbine throttle valve position indication problems that were discovered during monthly turbine valve testing. The limit switches were discovered to be in a position that did not leave sufficient margin for thermal expansion. A probable cause was that the limit switches were adjusted too close to the reset point when they were calibrated during the recently-completed maintenance and refueling outage. The limit switches were re-adjusted and no further problems were noted.

- Following re-adjustment of the turbine throttle valve position limit switches, the plant resumed full power operation until August 11, 1995 when power was reduced to troubleshoot reactor feedwater pump speed control problems. Following adjustments to the feedwater speed control linkage and repairs to the actuator in the governor control system, the plant returned to full power operation for the remainder of the month.

September 1995

- The plant operated at or near full power during the month.

October 1995

- The plant operated at or near full power during the month.

November 1995

- The plant operated at full power until November 3, 1995 when power was reduced to perform maintenance on the Control Rod Drive System and to conduct scram time testing.
- Except for entering economic dispatch (load following) at the request of the Bonneville Power Administration on November 26 and 28, 1995, the plant operated at or near full power for the remainder of the month.

December 1995

- The plant was placed on economic dispatch (load following) for the most of the month at the request of the Bonneville Power Administration. The plant returned to full power operation at the end of the month.

2.4 SIGNIFICANT CORRECTIVE MAINTENANCE PERFORMED ON SAFETY-RELATED EQUIPMENT

This information is provided in accordance with the guidance of Regulatory Guide 1.16, Section C.1.b(2)(e). In addition to safety-related equipment, components considered to be essential for power generation are also included.

2.4.1
Reactor Building Exhaust Monitoring System

Software and hardware upgrades were installed in the Reactor Building Exhaust Monitoring System. The upgrades were made to improve the reliability of the system.

2.4.2
Containment

Drywell Purge Supply Valves CSP-V-1 and CSP-V-2 and Wetwell Airspace Purge Exhaust Valves CEP-V-3A and CEP-V-4A were replaced with new valves which torque closed into metal seats and have larger actuators to provide for higher torque requirements. This change was made to improve seat leakage performance and reduce the potential for forced outages due to local leak rate testing considerations.

2.4.3
Acoustic Monitoring System

The Acoustic Monitoring System was removed to reduce significant maintenance costs and Control Room indication was replaced with the Linear Variable Differential Transformer (LVDT) output associated with the set pressure device for the main steam relief valves.

2.4.4
Main Steam System

- The dual (fast operation) and single (slow closure for testing) solenoids on the Main Steam Isolation Valves were replaced with a three-valve manifold. The three-valve manifold is qualified for six years. The previous design was qualified for only two years.

- The Main Steam Line Radiation Monitor trip functions were eliminated to improve plant availability by eliminating unnecessary challenges to equipment important to safety.

2.4.5
Neutron Monitoring System

- A total of 12 model NA-200 top-entry Local Power Range Monitor (LPRM) assemblies were replaced with improved model NA-250 bottom-entry LPRM assemblies.

- A total of four Source Range Monitors (SRMs) and eight Intermediate Range Monitors (IRMs) were replaced with an eight-channel, General Electric wide range neutron monitoring system. The new system is designed to reduce maintenance and radiological (ALARA) costs and provide for simplified startup operations.

2.4.6
Control Rod Drive System

The Scram Solenoid Pilot Valve (SSPV) diaphragms were replaced with a Viton material for several control rods. The replacement was performed to changeout BUNA-N material that was experiencing premature hardening and loss of flexibility. In addition, system hard tubing was replaced with flex hose to minimize replacement time and reduce maintenance costs.

2.4.7
Service Water System

Control power circuits were added to Service Water Loop Return Isolation Valves SW-V-12A and SW-V-12B to comply with the monitoring recommendations of Regulatory Guide 1.47.

2.4.8
Containment Electrical Penetrations

A total of seven electrical penetration modules were replaced, destructive examinations were performed of recently removed modules, and insulation resistance testing was conducted for those modules which were not replaced.

These efforts were undertaken due to indications being discovered, during the 1993 operating cycle, of moisture intrusion into a containment electrical penetration module containing non-safety related rod position indication system cables. Investigation at that time discovered an apparent generic problem with containment electrical penetration modules using Scotchguard strain relief material with varglas wiring insulation. All safety-related Scotchcast/Varglas modules exhibiting the elements of degradation have been replaced.

Followup efforts and the detailed evaluations and analyses during the 1995 outage determined that additional module replacement and inspection efforts were not necessary. The existing modules, not containing the combination of Scotchcast/Varglas, are operable for both electrical and containment integrity functions.

2.4.9
Reactor Water Cleanup System

Instrumentation was installed to allow for the detection and alarm of high flow conditions in the Reactor Water Cleanup blowdown line. This was completed to resolve operational limitations on blowdown line and system heat exchanger valves and to meet design requirements.

2.4.10
Supervisory System

Division "B" Supervisory System equipment was replaced. This system division interfaces with the Meteorological Monitoring, Circulating Water, Plant Service Water, Fire Protection and Tower Makeup Systems.

2.4.11
High Pressure Turbine

The High Pressure Turbine was disassembled and inspected. Non-Destructive Examination of the rotor and blade rings revealed no major concerns.

2.4.12
Shroud Head Bolts

A total of 36 new shroud head bolts were replaced as a precautionary measure due to cracking of shroud bolts being observed at different Boiling Water Reactor plants.

2.4.13
Reactor Feedwater System

The "A" Reactor Feedwater Turbine Actuator was replaced following a reactor feed pump speed divergence and reactor level transient that occurred during August 1995. Vendor misadjustment of the actuator was the likely cause. Full travel and smooth operation of the replacement actuator and the associated governor valve were noted during post-installation testing.

2.4.14
High Pressure Core Spray System

The six-year overhaul of High Pressure Core Spray (HPCS) System Diesel Generator HPCS-DG-3 was performed. This effort consisted of 1) removal and inspection of each cylinder power assembly (power pack) and replacing the elastomers, gaskets and seals, 2) replacement of the elastomer boot in each of the diesel starting air pressure control valves, 3) replacement of the coupling spider on the engine and motor-driven fuel oil pumps, 4) cleaning and inspection of the governor pneumatic booster, and 5) cleaning of the lube oil separator and inspection of the camshaft drive gears.

2.5 FUEL PERFORMANCE

This section is provided in accordance with the guidance of Regulatory Guide 1.16, Revision 4, Section C.1.b.(4).

During 1995 the Supply System modified a WNP-2 FSAR commitment pertaining to surveillance of post-irradiated fuel. As part of our routine fuel inspection program that was described in the WNP-2 FSAR, a visual examination was to be performed on five to ten percent of the highest burnup assemblies of the discharged fuel after each refueling. The visual examination was for the detection of indications of generic gross cladding defects or anomalies that may have occurred during operation. This commitment was accepted by the NRC in the WNP-2 Safety Evaluation Report, as adequately addressing the issue of post-irradiation surveillance.

As an alternate approach, the Supply System evaluated post-irradiation fuel inspection activities and determined the acceptability of visual inspection only on discharged fuel where there was indication of either actual or suspected gross cladding defects or anomalies. Examples of such indications include increased Offgas System activity and negative impacts on water chemistry parameters. This change to the post-irradiation surveillance program was incorporated into Amendment 50 to the WNP-2 FSAR.

Based on plant operational indicators, there was no evidence of fuel performance problems during Cycle 10. Accordingly, a visual inspection of the discharged fuel was determined to be unnecessary.

2.6 10CFR50.59 CHANGES, TESTS, AND EXPERIMENTS

Federal Regulations (10CFR50.59) and the Facility Operating License (NPF-21) allow changes to be made to the facility and procedures as described in the Safety Analysis Report, and tests or experiments to be conducted which are not described in the Safety Analysis Report without prior Nuclear Regulatory Commission (NRC) approval, unless the proposed change, test or experiment involves a change in the Technical Specifications incorporated in the license or an unreviewed safety question. In accordance with 10CFR50.59, summaries of the safety evaluations completed for activities implemented during 1995 are included in this section.

2.6.1 PLANT MODIFICATIONS

Permanent plant modifications at WNP-2 are implemented by means of a Basic Design Change (BDC) or Plant Modification Record (PMR). The following BDCs and PMRs implemented in 1995 required a Safety Evaluation in accordance with 10CFR50.59. Each permanent change was evaluated and determined to neither represent an Unreviewed Safety Question nor require a change to the WNP-2 Technical Specifications.

2.6.1.1
BDC 55-2927-0A

This BDC provided for the alteration of the design standards for the Reactor Water Cleanup (RWCU) System. Quality Group C (ASME Section III, Class 3) portions of the system were reclassified to Quality Group D (ANSI B31.1 for piping).

It was concluded from the safety evaluation that the safety function of the RWCU System pressure boundary remains unchanged after this modification. The portion of the system affected by this change is not required to accomplish this safety function. Offsite dose consequences of breaks in the specified parts of the RWCU system are bounded by the Reactor Feedwater System line break outside containment. Therefore, the activity would not increase the consequences of an accident evaluated previously in the Licensing Basis Documents (LBDs).

2.6.1.2
PMR 87-0048-4E

This PMR provides for a design change to revise the design data base and furnish instructions for the replacement of the equipment associated with Division "B" Supervisory Control System.

It was concluded from the safety evaluation that the proposed modification has no direct affect on the probability of an accident occurring. The new Supervisory Control System will perform the same function as before. The mounting hardware is essentially identical, therefore, the new mounting is considered to be qualified. Implementation and testing of this modification was completed during the last outage and will have no direct or indirect affect on safety related equipment. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.3
PMR 87-0273-OA

This PMR provided for the addition of loss of control power sensing relays for the motor operators of Standby Service Water Valves SW-V-12A and SW-V-12B to provide input to the existing Service Water System Bypass/Inoperable Status Indication (BISI).

It was concluded from the safety evaluation that there was no change in the functional design of the valves. The relays are Quality Class I and seismically mounted to maintain their electrical integrity during a design basis event. The design change only provides an inoperable status indication in the event of a loss of control power to SW-V-12A and SW-V-12B. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.4
PMR 89-0299-06

This PMR revision provided for the replacement of Containment Atmosphere Control (CAC) System Level Transmitter CAC-LT-1B. The Barton Model 386 instrument was replaced with a Rosemount Model 1153 unit.

It was concluded from the safety evaluation that the replacement of the transmitter does not make any change to the function of the CAC System. The CAC System is not an accident initiator and would only be used following a design basis accident if and when hydrogen and oxygen concentrations in primary containment approach explosive levels. Both the original Barton transmitter and the new Rosemount produce a 4mA to 20mA signal based on a differential pressure input. The new Rosemount transmitter has the same function as the existing transmitter and, as a result, the replacement maintains the original design function. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.5
PMR 89-0356-0

This PMR provided for the replacement of ASCO dual solenoids on the Main Steam Isolation Valves (MSIVs) with a new approved design.

It was concluded from the safety evaluation that the nuclear safety function of the MSIVs remains unchanged after this modification. The new Solenoid Pilot Valves (SPVs) installed by this PMR will be less susceptible to seal degradation and other impacts on qualified life than existing SPVs. The new mounting configuration uses a single manifold assembly for all three solenoid pilot valves in order to reduce the complexity of pneumatic and electrical connections. No change is to be made to the electrical input, the air supply or the pneumatic output from the SPVs, which ensures that the same logic is maintained. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.6
PMR 90-0057-OA

This PMR provides for modification of the High Pressure Core Spray (HPCS) System battery racks and enclosures to permit unrestricted access.

The structural design of the new HPCS battery racks design is equal to or better than the original rack under all load conditions. The existing enclosure was removed and a new acrylic cover was installed. The installation and testing of the new battery rack was performed during the last outage. Therefore, the activities associated with the modifications to the battery rack and enclosure will not increase the probability of occurrence of any accident previously evaluated in the LBDs.

2.6.1.7
PMR 90-0305-4E

This PMR provides for the removal of old and replaced equipment, spare associated cables and modification of the Particulate and Iodine Sample System.

It was concluded from the safety evaluation that there was no impact to LBD analysis. The function of Reactor Building (RB) Stack flow and effluent monitoring system is to evaluate the consequences of an accident. Therefore, the monitor is not an accident initiator and cannot contribute to the possibility of a previously evaluated accident. This modification does not represent a change in plant capability. The monitoring systems will continue with equipment of equal or better capability as that being replaced. Accordingly, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.8
PMR 90-0319-0A

This PMR provides for installation of raised curb in the instrument rack rooms to prevent combustible liquid intrusion.

The curb is a passive device that does not interact with other plant equipment. The sole purpose of the curb is to prevent flammable liquids from passing under the door. Therefore, the installation of the curb will not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.9
PMR 91-0071-4AB

This PMR provides strengthening of the attachment welds for Residual Heat Removal (RHR) System vent valve assembly RHR-V-250 to reduce susceptibility to fatigue induced failures.

The design function of this instrument line remains unchanged as a result of this modification. This modification is changing the weld attachments, at the point connected to the main pipe, to increase their strengths. Therefore, the activity will not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.10
PMR 91-0153-01

This PMR revision provided for the installation of four wall penetrations through the Diesel Generator Building Day Tank Rooms to facilitate periodic flushing of the Fire Protection Sprinkler System.

It was concluded from the safety evaluation that the new pipe sleeves would be designed, installed and maintained such that there would be no degradation or invalidation of any fire wall rating. The sleeves were also to be installed above the predicted elevation of the fuel oil, assuming a rupture of the day tank. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.11
PMR 91-0293-0A

This PMR provided for elimination of the Main Steam Line Radiation Monitor (MSLRM) scram, Main Steam Isolation Valves (MSIVs) and main steam drain valves closure functions, and condenser isolation by sparing relay contacts located in panels in the main control room. This design change will reduce the potential for unnecessary reactor shutdowns caused by the spurious actuation of MSLRM trips. This design modification was a followup activity for WNP-2 Technical Specification Amendment 112.

It was concluded from the safety evaluation that there was no impact to the LBD analysis. Removing the main steam line radiation monitor trips and isolations will decrease the frequency of operation of equipment important to safety. The hardware changes required to effect these changes involve only electrical and logic wiring changes in control room panels. Thus, the changes will not have any direct affect on safety related equipment. Accordingly, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.12
PMR 91-0445

This PMR provided for the modification to the Containment Instrument Air (CIA) System by installation of a particulate filter upstream of valves CIA-PCV-2A and CIA-PCV-2B, removal of full-bore restricting orifices CIA-20-1A and CIA-20-1B and associated flanges, and addition of an isolation valve on the low pressure (test) port of valves CIA-PCV-2A and CIA-PCV-2B.

It was concluded from the safety evaluation that none of the changes negatively affected the ability of the CIA System to perform its design function of providing pressurized nitrogen to the main steam relief valves. The addition of the filter increases the reliability of the CIA System by preventing particles from fouling the seat rings in the pressure control valve. The addition of the capped isolation valve neither increases or decreases the reliability of the system. However, its addition simplifies the testing process used to ensure that the pressure control valve

is set properly. The orifice plate is full-bore, served no purpose and was being removed to simply make room for the filter. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.13
PMR 93-0048

This PMR provides for removal of Main Steam Traps MS-T-1A, MS-T-1C and MS-T-1D; removal of Drain Valves MS-V-119A, MS-V-119C, MS-V-119D, MS-V-238A, MS-V-238C and MS-V-238D; and installation of new pipe nipples and pipe caps.

It was concluded from the safety evaluation that there was no impact to the LBD analysis. Since the trap drip leg drain valves cannot be isolated at power, the work was completed during the last outage. There is no safety related equipment adjacent to the work area. It was also concluded that the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.14
PMR 93-0089

This PMR provided for the installation of a continuous backfill modification which will divert a continuous flow at one-to-four lbm/hr Control Rod Drive (CRD) System water into five water level instrument reference legs. This modification allows for mitigation transport of dissolved noncondensable gas down in the reference legs.

It was concluded from the safety evaluation that analysis and field testing of the proposed backfill system have shown there is no increased risk of a reactor scram or other trips caused by system installation. A review of instrument trips and single failure determined that there are no new accident scenarios introduced by the change. All plant systems and components required to mitigate the consequences of accidents previously evaluated will be unaffected by the existence of this modification. A CRD break in the Reactor Building is bounded by much larger events which have the potential of releasing radioactive material offsite. Water from a leak would eventually end up in the floor drains or the Emergency Core Cooling System (ECCS) pump rooms. However, the small leak is bounded by existing line break and flooding analyses. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.15
PMR 93-0132-0A

This PMR provided for changing the Main Steam Relief Valve (MSRV) MS-RV-1B and MS-RV-1C setpoints from 1150 psig to 1165 psig as part of the reactor power uprate implementation, in order to preserve simmer margins.

It was concluded from the safety evaluation that the safety function of the MSRV remains unchanged after this modification. The setpoint change in support of the 15 psi increase in reactor pressure is consistent with the licensing basis. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.16
PMR 93-0132-0B

This PMR provided for installation (calibration) and testing of the Reactor Power Uprate instrument setpoint changes.

It was concluded that no new equipment was being installed and no were changes made to equipment other than setpoint changes. Therefore, the probability of occurrence of previously analyzed in the LBDs is not increased.

2.6.1.17
PMR 93-0157-1B

This PMR replaces four containment supply/exhaust purge valves to improve Local Leak Rate Testing (LLRT) performance. The replacement valves are metal-to-metal seated, which also allows a lower period between required LLRT tests.

It was concluded from the safety evaluation that there was no impact to LBDs analysis. The new valves were fabricated to the same closing time and seat leakage requirements as the existing valves. The new metal-to-metal seats will have improved leakage characteristics. Therefore, the proposed activity will not increase the consequences of a malfunction of equipment important to safety.

2.6.1.18
PMR 93-0190-0A

This PMR provided for the removal of the Valve Position Indication (VPI) system that drives the main steam relief valve indicating lights on Control Room Panel P601, and removal of the Acoustic Monitoring System for the Main Steam Relief Valves.

It was concluded from the safety evaluation that the VPI system performs the same function of monitoring SRV leakage as the Acoustic Monitoring system to be replaced after this modification, by direct monitoring rather than indirect. Failure of this new indicating system would not affect any safety related systems or components and, therefore, would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.19
PMR 93-0195-0A

This PMR provides for installation of eight new manual isolation valves to the Plant Service Water (TSW) System in the Turbine Building.

It was concluded from the safety evaluation that there was no impact to the LBD analysis. This installation has no additional affect on the plant than any other routine maintenance which requires the TSW system to be out of service. The TSW system is not safety related. Furthermore, this activity does not constitute a change which could affect the design, design safety function or method of performing the design safety function as described in the LBDs.

2.6.1.20
PMR 94-0048-4E

This PMR eliminated degradation concerns in Module 2 of Containment Penetration X101A by replacing it with a new module of improved design. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this change is within the limits established by the LBD accident and event analysis. The electrical function of the replacement containment penetration module is required to be similar to the existing module. The existing circuitry utilizing the containment penetration module will meet the original design, including conductor splices in the inboard terminal boxes. New failure modes will not be introduced by this change. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.21
PMR 94-0048-05

This PMR provided for the replacement of Module 3 of Containment Penetration X101A modules. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this design change would have no impact involving safety-related function or design of the containment penetrations. The replacement module is identical in form, fit, and function to the existing module in its role as a containment boundary. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.22
PMR 94-0048-6G

This PMR eliminated degradation concerns in Module 1 of Containment Penetration X101C by replacing it with a new module of improved design. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this change is within the limits established by the LBD accident and event analysis. The electrical function of the replacement containment penetration module is required to be similar to the existing module. The existing circuitry utilizing the containment penetration module will meet the original design, including conductor splices in the inboard terminal boxes. New failure modes will not be introduced by this change. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.23
PMR 94-0048-07

This PMR provided for the replacement of Module 2 of Containment Penetration X101C modules. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this design change would have no impact involving safety-related function or design of the containment penetrations. The replacement module is identical in form, fit, and function to the existing module in its role as a containment boundary. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.24
PMR 94-0048-8J

This PMR eliminated degradation concerns in Module 1 of Containment Penetration X101D by replacing it with a new module of improved design. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this change is within the limits established by the LBD accident and event analysis. The electrical function of the replacement containment penetration module is required to be similar to the existing module. The existing circuitry utilizing the containment penetration module will meet the original design, including conductor splices in the inboard terminal boxes. New failure modes will not be introduced by this change. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.25
PMR 94-0048-9K

This PMR eliminated degradation concerns in Module 2 of Containment Penetration X101D by replacing it with a new module of a superior design.

It was concluded from the safety evaluation that this change is within the limits established by the LBD accident and event analysis. The electrical function of the replacement containment penetration module is required to be similar to the existing module. The existing circuitry utilizing the containment penetration module will meet the original design, including conductor splices in the inboard terminal boxes. New failure modes will not be introduced by this change. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.26
PMR 94-0049-OA

This PMR provided for the addition of a fire detector in the Diesel Generator Building due to the inoperability of a fire seal installed in a wall separating Divisions 1 and Divisions 2 of Diesel Exhaust Room D207. Modification of the seal was determined to be not an option at the time.

It was concluded from the safety evaluation that the fire detector is an "important to safety" device which provides defense in depth to protect those systems, structures and components credited for safe shutdown in the event of a design basis fire. Safe shutdown post-fire is not credited in the LBDs as required during a design basis accident. However, installation of the fire detector would aid in reducing the consequences of an accident by early detection of a fire in the diesel generator building. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.27
PMR 94-0114

This PMR provided for the correction of a design error by replacement of spring-loaded Excess Flow Check Valves PI-EFC-X72F and PI-EFC-X73E with swing check valves on the return lines from Containment Monitoring System (CMS) Air Monitors CMS-SR-20 and CMS-SR-21.

It was concluded from the safety evaluation that no new mode of operation of any equipment results from this valve change. Installation of the new swing check valve ensures that the plant is in conformance with the analyzed design basis and provides assurance that primary containment integrity will be maintained for a design basis LOCA event. The proposed activity satisfies regulatory design criteria by using a solenoid valve outside containment and a simple check valve inside containment. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.28
PMR 94-0104-0

This PMR provided for the modification of the refuel floor arrangement and design of equipment for the performance of new fuel receipt inspection of ABB fuel.

It was concluded from the safety evaluation that the function of the jib crane and the fuel inspection stand remains unchanged after this modification. Since the new designs are relocations of items, the travel path is redesigned (addressed as a procedure revision) so the margin for of safety will not be reduced. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.29
PMR 94-0144

This PMR provided for the removal and replacement of the existing Position 3 Module for Containment Penetration X105C, and transfer of the wiring from the Position 2 Module to the Position 3 Module. The modification to the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this design change would have no impact involving safety-related function or design of the containment penetrations. The replacement module is identical in form, fit, and function to the existing module in its role as a containment boundary. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.30
PMR 94-0158

This PMR provided for the replacement of Module 3 of Containment Penetration X100A modules. The replacement of the module was needed in order to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this design change would have no impact involving safety-related function or design of the containment penetrations. The replacement module is identical in form, fit, and function to the existing module in its role as a containment boundary. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.31
PMR 94-0159-0A

This PMR provided for removal and replacement of Module 3 of Containment Penetration X100B with a module of improved design to correct low/high insulation resistance values for installed circuits.

It was concluded from the safety evaluation that this change is within the limit established by the LBDs accident and event analysis. The form, fit and function of the replacement containment penetration module is similar to that of the existing modules as it applies to the safety related pressure boundary function. The circuitry utilizing the containment penetration module will meet the original design, function, and electrical separation requirements. Therefore, no mechanism exists for the possibility of an accident of a different type as a result of this activity.

2.6.1.32
PMR 94-0177-0A

This PMR provides for the installation of an auxiliary work platform on the 606' refueling floor which will span the reactor cavity.

It was concluded from the safety evaluation that there was no impact to LBD analysis. The types of work to be performed from the auxiliary work platform are those already routinely performed and no new in-vessel or spent fuel pool tasks are created by this change. In addition, the jib hoists are not capable of lifting a fuel bundle. Therefore, this change did not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.1.33
PMR 94-0201

This PMR provided for the modification of the control circuits for Containment Monitoring System (CMS) Containment Isolation Valves PI-VX-251 and PI-VX-257 in Sample Racks CMS-SR-20 and CMS-SR-21 to comply with the licensing basis. The change was made to ensure that no active single failure would result in the loss of containment integrity.

It was concluded from the safety evaluation that changing the indication and control power for Containment Isolation Valve PI-VX-251 from Division 1 to Division 2, and Division 2 to Division 1 for Containment Isolation Valve PI-VX-257 does not increase the probability of an accident. These solenoid valves are energized (open) during plant operation, startup and hot shutdown modes so that the drywell atmosphere monitoring system (Sample Racks CMS-SR-20 and CMS-SR-21) can be used to assist Plant Operations personnel in detecting primary system leakage. The solenoid valves de-energize to isolate (close) upon receipt of an "FA" isolation signal (High Drywell Pressure and Reactor Vessel Water Level 2). Changing the divisional source of control power for the valves mitigates the consequences of a single failure within either division isolation logic by powering one of the two series isolation valves from the other

division. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.34
PMR 94-0216-0

This PMR provided for the removal and replacement of module 3 in containment electrical penetration X102A, used by Reactor Recirculation (RRC), Reactor Water Cleanup (RWCU), Containment Monitoring (CMS), Main Steam (MS), and Loose Parts Detection (LPDS) Systems. The module replacement is due to potential loss of wire insulation resistance resulting from epoxy degradation.

It was concluded from the safety evaluation that the containment penetration function as part of the accident mitigation system remains unchanged after this modification. Upon completion of this activity, all affected systems circuitry will function correctly using the original circuit components. The PMR will not change inputs to these systems, and the replacement module pressure boundary design is to maintain the design, function, and separation requirements. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.35
PMR 94-0270-0

This PMR provided for the addition and mitigation instrumentation and logic to detect and isolate a previously unanalyzed High Energy Line Break (HELB) in the Reactor Water Cleanup (RWCU) System blowdown to the condenser. This activity adds the automatic isolation of valves RWCU-V-1 and RWCU-V-4 when a RWCU HELB occurs at the terminal end (which is defined as valve RWCU-V-33).

It was concluded from the safety evaluation that this modification is for accident detection and mitigation, and is not considered an accident initiator. This change is to resolve an unreviewed safety question. Therefore, the activity does not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.36
PMR 94-0284-0A

This PMR provides three pressure test points for troubleshooting diagnostics on the "B" Steam Jet Air Ejector System.

The addition of three pressure test points in the steam jet air ejector control piping will not increase the probability of any accidents evaluated previously in the LBDs. The new pressure test points do not impact the ability to safely isolate the Steam Jet Air Ejector System.

2.6.1.37
PMR 94-0319-0

This PMR provides for the replacement of control room toilet Radwaste Exhaust Air (WEA) System Fan WEA-FN-51.

The replacement control room toilet fan was built to the same overall dimensions and equivalent flow rating as existing fan. Therefore, this change would not increase the probability of an occurrence of an accident evaluated previously in the LBDs.

2.6.1.38
PMR 94-0339-0

This PMR provided for the modification of control circuits for Residual Heat Removal (RHR) System Valves RHR-V-24B, RHR-V-27B and RHR-V-64B, such that the valves are in compliance with Appendix R Control Room fire protection requirements.

This modification protects the Post-Fire Safe Shutdown function of valves RHR-V-24B, RHR-V-27B, and RHR-FCV-64B from fire induced "hot" shorts by enclosing their manual control switches in metal boxes and routing the starter-side wiring in metallic flexible conduit. Immediate Operator actions to isolate these valves in the event of a fire can be deferred until later, when the Remote Shutdown Panel is energized after evacuating the Control Room. Control relays RHR-RLY-K54B, RHR-RLY-K120B, and RHR-RLY-K123 are being changed from GE type HFA and HMA to Struthers-Dunn relays. It was concluded that the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.1.6.39
PMR 94-0375-0A

This PMR provides modification of the Reactor Water Clean Up (RWCU) System in order to restore the proper functioning of the filter demineralizers and enhance reactor water chemistry. This includes removal of two RWCU System piping "dead legs."

This design change has no direct influence on any important to safety equipment. Removal of the chemical waste discharge line does not impair the ability of the RWCU System to remove solid and dissolved impurities from reactor coolant. Chemical cleaning of the RWCU System can still be accomplished using mobile equipment. Thus, there is no indirect effect on any important to safety equipment. Therefore, the modification does not increase the consequences of an accident evaluated in the LBDs.

2.1.6.40
PMR 94-0386-0

This PMR provided for the replacement of control of non-ADS (Automatic Depressurization System) Safety Relief Valves MS-RV-2A, MS-RV-2C and MS-RV-3B with ADS Safety Relief valves MS-RV-3D, MS-RV-5B and MS-RV-5C on the Alternate Remote Shutdown panel.

The safety relief valves currently controlled from the Alternate Remote Shutdown panel are non-ADS valves with only the pressure relief function. Nitrogen supply for the pressure relief function is supplied by a ten gallon accumulator for each valve. The ADS valves have the same pressure relief function but also have two redundant divisional ADS functions. As these safety relief valves have an additional 42 gallon accumulator for the ADS function, this will provide sufficient nitrogen capability to depressurize the reactor, and is not affected by the normal pressure relief function of the safety relief valve. This PMR does not make any logic changes to either the pressure relief functions or the ADS functions of the valves. Therefore, the consequences of a malfunction are not increased over evaluated previously in the LBDs.

2.6.1.41
PMR 94-0418-0A

This PMR provided replacement of twelve Local Power Range Monitor (LPRM) assemblies with improved models. The new LPRM design will provide longer life, ease of electrical connection, reduce exposure of personnel and eliminate rapid changes in detector sensitivity, spiking, and loss of insulation resistance.

It was concluded from the safety evaluation that this change is within the limit established by the LBD accident and event analyses. The proposed change will not result in any changes to the operation of the system. The function of the equipment will be the same. The installation and testing of the equipment was completed during the last outage to not create new or different activities which challenge important to safety equipment. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.42
PMR 94-0437-0

This PMR provided for the installation of isolation valves in the supply and return Plant Service Water (TSW) System piping so that a temporary chiller can provide cooling to the Reactor Closed Cooling (RCC) Water System heat exchangers during outages, for more efficient drywell cooling and planned circulating water outages.

It was concluded from the safety evaluation that the function of the TSW system remains unchanged after this modification, removing heat from non-safety related plant equipment. The TSW system will perform all of its design functions following the implementation of this design change. This PMR is not adding any safety related functions that must be performed.

Furthermore, it was concluded that the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.43
PMR 95-0097-0A

This PMR provided for the revision of the electrical design calculations and mechanical and electrical engineering drawings and databases for new Service Water (SW) System Pump Motor SW-M-P/1B.

This design, function and qualification of the replacement motor is the same as the existing service water motor. Therefore, this activity will not change the function or margin of safety as defined by the LBDs. Performance testing of the motor/pump and the service water system will not affect nuclear safety. Furthermore, it was concluded that the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.44
PMR 95-0098-0A

This PMR provided for replacement of installed air regulators to increase the air supply pressure to scram discharge volume vent and drain valves.

The replacement and increase of the Control Rod Drive setpoint from 20 psig to approximately 50 psig would not influence the accident assumptions contained in the LBDs. The increase pressure will improve the non-safety related opening function of the valves. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.45
PMR 95-0135-0A

This PMR provided direction to build, install and field adjust a dynamic absorber installed on top of Standby Service Water Pump Motor SW-MO-1B to provide for vibration reductions.

The proposed installation of a tuned mass vibration absorber does not change the functional design or operating parameters of the Service Water (SW) System. Therefore, the ability of the SW System to perform its accident mitigation functions will not be adversely affected by the proposed modifications. Therefore, the proposed activity does not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.46
PMR 95-0147-0

This PMR provided for the improvement of the power supply to Breaker E-MC-8B and E-MC-8BB through recalibration of Breaker E-CB-81/8B. This provided adequate ampacity for bus loads.

It was concluded from the safety evaluation that the safety function of E-MC-8B is improved after this modification. Since the calculated maximum LOCA loading exceeded the minimum operating current of the feeder circuit breaker overcurrent trip device, recalibration is a way to increase reliability margin for correct operation during postulated events. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.47
PMR 95-0150-0

This PMR provided for the improvement of the power supply to E-MC-7B through recalibration of breaker E-CB-71/7B, and E-MC-7BB through recalibration of breaker E-CB-7B3C. This provided adequate ampacity for bus loads.

It was concluded from the safety evaluation that the safety function of the E-MC-7B and 7BB are improved after this modification. Since the calculated maximum LOCA loading exceeded the minimum operating current of the feeder circuit breaker overcurrent trip device, recalibration is a way to increase reliability margin for correct operation during postulated events. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.1.48
PMR 95-0152

This PMR provided for the motor and gear changeout for Reactor Core Isolation Cooling (RCIC) System Valve Motor RCIC-MO-63. The reason for the modification was to increase the thrust and torque capability from 60 ft-lbs to 80 ft-lbs, decrease inertial thrust and torque by changing the motor speed from 3400 rpm to 1700 rpm, and increase gear rating by changing the overall unit ratio. This was based on valve testing results which indicated that inertial torque had caused the operator gear rating of 1250 ft-lbs to be exceeded by 50 percent.

It was concluded from the safety evaluation that RCIC-V-63 is not a potential initiator of any accidents evaluated previously in the LBDs. The objective of this modification was to bring the measured torque within the gear rating by use of 1700 rpm motor without casing the maximum stroke time to be exceeded and without reducing available thrust and torque margins. Valve RCIC-V-63 is the inboard containment isolation valve for the RCIC turbine steam supply line. This valve provides High Energy Line Break (HELB) isolation under the maximum differential pressure of 833 psi. Accordingly, RCIC-V-63 mitigates the consequences of line breaks outside and inside of containment. The effect of this modification is to decrease the consequences of an accident by enhancing the operability of the valve operator. The change does not affect the functional objective of RCIC-V-63 to remain open during an ATWS condition and to close during a HELB scenario. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.1.49
PMR 95-0197-0A

This PMR re-supplies the source of power to the position indicating lamp circuits for the Main Steam Isolation Valves (MSIVs) and Traversing Incore Probe (TIP) System Valve TIP-V-15 from the non-safety related to a standby safety related source to ensure that Operations personnel can verify containment integrity during post-accident conditions.

The installation was implemented during the last outage when no containment isolation functions were required for the MSIVs or the TIP valve. These changes do not adversely affect safety system or Plant Operator accident or transient responses. The changes also do not create the possibility of an accident of a different type than any evaluated in the LBDs. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.2 TEMPORARY MODIFICATIONS AND INSTRUMENT SETPOINT CHANGES

The following are summaries of temporary modifications, instrument setpoint changes and motor-operated valve setpoint changes. As required by 10CFR50.59, each change was evaluated and determined to neither represent an Unreviewed Safety Question nor a change to the WNP-2 Technical Specifications. Temporary modifications are made by means of the Temporary Modification Request (TMR) process, instrument setpoint changes are made under the Instrument Setpoint Change Request (ISCR) process and motor-operated valve setpoint changes are made under the MOV Setpoint Change Request (MSCR) process.

2.6.2.1
TMR 95-005

This TMR provided for the modification to restore control rod position indication for Control Rod 22-03 by accurately monitoring the status of the control rod reed switches in the rod position indicating probe and then to properly convey the position indication information to the Rod Position Indication System (RPIS) electronics.

The proposed modification will allow the RPIS rod position indication electronics to function as originally designed. This modification does not create the possibility of any accident evaluated previously in the LBDs. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.2.2
TMR 95-008

This TMR provided for adding a load to the 6.9kV Bus SH-6. The purpose of the modification is to power the Adjustable Speed Drives (ASDs) in a test mode.

The planned testing of the ASD drives using a test set will not increase the probability of occurrence of an accident previously evaluated in the LBDs. Following the completion of the test, all of the temporary changes will be returned to the original condition. Since the temporary modification and resultant testing do not change any accident analysis or result in additional accident initiators, they do not increase the probability of occurrence of an accident previously evaluated.

2.6.2.3
TMR 95-010

This TMR provided for the refuel bridge cable to be disconnected for maintenance. This means the bridge's interlock logic input would falsely indicate that the bridge is over the core. This required installation of jumpers, sending signals that the refueling bridge is not over the core, in order to perform startup surveillances.

The consequences of an accident evaluated previously in the LBDs is contingent on either refueling activities or rod withdrawal with head removed. Neither of these conditions will exist prior to removal of the temporary modification. Assurance that neither of these conditions may take place is made by the location of and status (tagged out) of the refuel platform. Therefore, this temporary modification would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.2.4
<u>TMR 95-030</u>

This TMR provided for the removal of disc position indication lights for a Reactor Core Isolation Cooling (RCIC) System head spray inboard check valve to allow for the valve to be removed for testing.

Removing the disc position light bulbs will not affect the operations of RCIC head spray inboard check valve for either opening during injection or closing when needed as a containment isolation valve. There is no postulated accident that could be caused be removal of the light bulbs. Therefore, there would be no possibility of the introduction of an accident of a different type than any evaluated previously in the LBDs.

2.6.2.5
<u>TMR 95-035</u>

This TMR provided for the removal of the electrical overspeed trip from the Reactor Core Isolation Cooling (RCIC) System turbine control logic.

Removal of the electrical overspeed trip from the RCIC turbine control logic will increase the reliability of the RCIC system. The mechanical overspeed trip provides the safety related function of overspeed protection and it is not affected by removing the electrical overspeed trip. As a result, the proposed activity will decrease the probability of occurrence of a malfunction of equipment important to safety evaluated previously in the LBDs. The activity would also not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.6
<u>TMR 95-037</u>

This TMR provided for a change in the source of makeup water to the Turbine Building ventilation fan air wash system.

It was concluded from the safety evaluation that the modification would not increase the consequences of an accident evaluated previously in the LBDs. The air washers serve no safety related or important safety equipment. There are no malfunctions of the washers which could be induced by this temporary modification which could increase the probability of malfunctions of equipment important to safety. The activity would also not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.7
<u>ISCR 1243</u>

This ISCR provided for revision of the response time setpoint for High Pressure Core Spray (HPCS) System Level Switches HPCS-LS-3A and HPCS-LS-3B to avoid inadvertent trips.

The change to instrument response time cannot increase the probability of occurrence of an accident or operational transient previously evaluated in the LBDs. The new response time setpoints remain within the design range for these instruments. The response time setpoint does not change any other of the instrument design characteristics. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.8
<u>MSCR 351</u>

This MSCR provided for revision to the Master Data Sheet for Main Steam (MS) System Valve Motor Operator MS-MO-20 to delete the minimum thrust setpoint and maximum and differential pressure. The MOV has since been removed from the Generic Letter 89-10 Program and, as result, is no longer required to be diagnostically tested (diagnostic testing is required if the Master Data Sheet specifies a thrust setpoint.

It was concluded from the safety evaluation that revision of the Master Data Sheet to control MS-V-20 by the torque switch setting would not increase the consequences of an accident evaluated previously. The torque switch setting is based on analysis (without testing). The MOV Master Data Sheet for MS-V-20 provides the necessary information to assure, analytically and with conservatism, that operator and valve design limits are not exceeded at the specified torque switch setting. The valve is used for accident mitigation and no changes have been made to valve function or normal and accident positions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.9
<u>MSCR 575</u>

This MSCR provided for revision to the Master Data Sheet for Reactor Core Isolation Cooling (RCIC) System Valve Motor Operator RCIC-MO-19 to decrease the minimum open and close thrust setpoint and increase the maximum and differential pressure. The changes were based on calculation revisions and the results of previous diagnostic testing.

It was concluded from the safety evaluation that decreasing the setpoint does not increase the probability that the valve will not perform its safety function under worst case differential conditions because the minimum setpoints are based on either analytical conservatism prescribed by calculation or bounding measured data. The increased maximum and differential pressure are determined to be the worst case design basis for the MOV and provides increased assurance that the valve will be set sufficiently high to close against such conditions. The reduced close

setpoint increases the reliability of the valve to open upon demand by providing additional margin to unseat the valve. In addition, the margin to the valve and operator design thrust and torque limits is increased. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.10
<u>MSCR 689</u>

This MSCR provided for revision to the Master Data Sheet for High Pressure Core Spray (HPCS) System Valve Motor Operator HPCS-MO-15 to increase the minimum close thrust. The change was made to reflect a larger mean seat diameter, determined by the vendor, to calculate the minimum close thrust.

It was concluded from the safety evaluation that the setpoints include conservative assumptions to provide assurance of successful operation during the most challenging scenario expected. The use of "mean seat diameter" in calculating the force to open and close a valve is consistent with most industry test results. Although use of "mean seat diameter" may increase or decrease the minimum thrust set point, the method provides increased assurance that the set point is appropriate. Accordingly, the change provides increased assurance of valve operation at design basis conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.11
<u>MSCR 716</u>

This MSCR provided for revision to the Master Data Sheet for Low Pressure Core Spray (LPCS) System Valve Motor Operator LPCS-MO-11 to increase the minimum close thrust. The change was made to reflect the addition of a rate of loading factor, determined from a previous test of the valve, into the minimum close thrust equation.

It was concluded from the safety evaluation that the calculational assumptions were based upon Supply System and industry in-situ and laboratory testing, and vendor recommended design limits. The setpoint is being changed because the diagnostic test indicates values different than assumed by calculation. Use of the measure values is valve-specific and, therefore, provides increased assurance that the set point is appropriate for the MOV. The proposed change to the close setpoint is intended to increase the reliability of the valve to operate by using actual measured data in the set point equation, while ensuring the design limits of the actuator and valve are not exceeded. The change also provides increased assurance of valve operation at design basis conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.12
MSCR 722

This MSCR provided for revision to the Master Data Sheet for Reactor Feedwater (RFW) System Valve Motor Operator RFW-MO-65A to increase the minimum close thrust. The change was made to reflect a larger running load, determined by static test of the valve, to calculate the minimum close thrust.

It was concluded from the safety evaluation that the calculational assumptions were based upon Supply System and industry in-situ and laboratory testing, and vendor recommended design limits. The setpoint is being changed because the diagnostic test indicates values different than assumed by calculation. Use of the measure values is valve-specific and, therefore, provides increased assurance that the set point is appropriate for the MOV. The proposed change to the close setpoint is intended to increase the reliability of the valve to operate by using actual measured data in the set point equation, while ensuring the design limits of the actuator and valve are not exceeded. The change also provides increased assurance of valve operation at design basis conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.13
MSCR 719

This MSCR provided for revision to the Master Data Sheet for Residual Heat Removal (RHR) System Valve Motor Operator RHR-MO-64B to increase the minimum close thrust. The change was made to reflect the addition of a loading factor into the minimum close thrust equation.

It was concluded from the safety evaluation that the calculational assumptions were based upon Supply System and industry in-situ and laboratory testing, and vendor recommended design limits. The setpoint is being changed because the diagnostic test indicates values different than assumed by calculation. Use of the measure values is valve-specific and, therefore, provides increased assurance that the set point is appropriate for the MOV. The proposed change to the close setpoint is intended to increase the reliability of the valve to operate by using actual measured data in the set point equation, while ensuring the design limits of the actuator and valve are not exceeded. The change also provides increased assurance of valve operation at design basis conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.14
MSCR 723

This MSCR provided for revision to the Master Data Sheet for Fuel Pool Cooling (FPC) System Valve Motor Operator FPC-MO-175 to increase the minimum close thrust. The change was made to reflect incorporation of a measured valve factor and rate of loading factor determined from testing.

It was concluded from the safety evaluation that the calculational assumptions were based upon Supply System and industry in-situ and laboratory testing, and vendor recommended design limits. The setpoint is being changed because the diagnostic test indicates values different than assumed by calculation. Use of the measure values is valve-specific and, therefore, provides increased assurance that the set point is appropriate for the MOV. The proposed change to the close setpoint is intended to increase the reliability of the valve to operate by using actual measured data in the set point equation, while ensuring the design limits of the actuator and valve are not exceeded. The change also provides increased assurance of valve operation at design basis conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.2.15
<u>MSCR 808</u>

This MSCR provided for revision to the Master Data Sheet for Reactor Closed Cooling (RCC) System Valve Motor Operator RRC-MO-40 to reduce the minimum open thrust. The change was made to reflect a more appropriate open setpoint to ensure that the MOV design limits are not exceeded.

It was concluded from the safety evaluation that the lower open setpoint provided the necessary overload protection while ensuring that the MOV would open under the maximum expected differential pressure conditions. The open setpoint change will not will not increase the close stroke time because the motor speed is unaffected by the change and the percentage of stroke length is either unchanged or reduced. Changing the open setpoint will not reduce the capability of the valve to close in the event of an accident, or its ability to open when required. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.3 FSAR CHANGES

General changes to the FSAR evaluated within the definition of 10CFR50.59 are reported in this section. FSAR changes are processed through the SAR Change Notice (SCN) process.

2.6.3.1
SCN 94-077

This SCN provided for revision of the Diesel Generator loading due to revised calculations. The diesel loading tables required revision upon loading changes.

It was concluded from the safety evaluation that revision of the loading schedules would not impact the consequences of an accident or reduce evaluation of the margin of safety. The diesel generators are accident mitigating features and, as such, cannot cause an accident. The calculations were revised to reflect current diesel loading and it was verified that the diesel generators would continue to perform their intended safety functions. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.3.2
SCN 95-007

This SCN provided for the revision of the "Post-Irradiation Surveillance" section so visual inspection of discharged fuel assemblies is performed only if there has been indications of gross cladding defects or anomalies during plant operation.

It was concluded from the safety evaluation that the change in the commitment would not result in an unreviewed safety question. There is sufficient industry and WNP-2 experience pertaining to examination of irradiated fuel through lead fuel assembly programs, lead test assembly programs and actual core reloads to provide an adequate level of confidence in the reliable performance of the WNP-2 fuel design. The LBDs allow operation with failed fuel as long as other limits, such as offgas, are not exceeded.

2.6.3.3
SCN 95-010

This SCN provided updating and correction to document the electrical penetration assemblies to agree with the original design specification.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. All electrical penetration replacement modules meet the WNP-2 design requirements for temperature, pressure, moisture and radiation for all the applicable normal and accident conditions, thus, maintaining the plant licensing criteria. Since this activity maintains all the WNP-2 original requirements and commitments, there is no increase in the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.3.4
SCN 95-013

This SCN provided for text and figures to reflect the correct postulated pipe break location for the Standby Liquid Control (SLC) System.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. Relocating the pipe break location will not increase the probability that the break will occur. The relocating of this break will not affect any plant equipment. Therefore, this revision will not increase probability of occurrence of malfunction of equipment important to safety that has been previously evaluated in the LBDs.

2.6.3.5
SCN 95-014

This SCN provided for inclusion of title changes resulting from reorganization and to indicate that central computer for Security System provides an automated decision as to whether or not access is authorized to vital areas.

It was concluded for the safety evaluation that an unreviewed safety question is not introduced as a result of this change. No change to security protecting equipment located in vital areas would be required (i.e., hardware or software changes to the security system computer or vital area portals would not be required). The probability of occurrence of a malfunction from a security perspective that creates additional threat to the public, or safety is not increased as a result of this change. Therefore, the activity would no increase the consequences of an accident evaluated previously in the LBDs.

2.6.3.6
SCN 95-018

This SCN provided for the implementation of Cycle 11 reload fuel and core design.

This activity does not introduce a new mode of operation nor create the possibility of an accident different from those previously evaluated in the LBD. The previously evaluated accidents systematically address all fuel characteristics, fuel related equipment malfunctions and operator actions. This precludes the possibility of an accident which has not been previously evaluated in the LBDs.

2.6.3.7
SCN 95-022

This SCN provided for clarification of the process for conducting contamination surveys upon exit from the Radiological Controlled Area (RCA) and release of personnel and personal items.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change.. This change allows all personnel to use tool monitors to do a quality check on their personal hand carried items that are considered clean. This does not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.3.8
SCN 95-023

This SCN provided for the revision of containment isolation valve description, fuel pool liner drainage description, valve designation description and a clarification discussion of separate trains.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. The Fuel Pool Cooling (FPC) System return line primary containment isolation valves are required to close and remain closed following a loss of coolant accident inside containment or other conditions when the unfiltered release of containment contents cannot be permitted. The use of motor operated gate valves for this application meets the design standards for the FPC System and for containment isolation valves. Furthermore, there is no affect on system performance. Therefore, this activity does not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.3.9
SCN 95-035

This SCN provided for revision of the references to a High Pressure Core Spray (HPCS) System diesel generator output breaker closure permissive on voltage. The word voltage was deleted. In addition, various editorial corrections were made that bring the description on the HPCS Diesel Generator in compliance with the as-built configuration of the plant.

It was concluded from the safety evaluation that the change would not result in the introduction of an unreviewed safety question. Since the HPCS Diesel Generator performs an accident mitigation role, an accident of a different type is not created by the editorial changes made. In the event of a LOCA or LOOP, the loss of HPCS Diesel Generator has been evaluated in the LBDs as the potential most limiting failure. Therefore, this activity does not create the possibility of an accident of a different type.

2.6.3.10
SCN 95-034

This SCN provided for modification and enhancement of the liquid radwaste effluent monitor set point calculation to assure compliance for liquid effluent concentration release to the public.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. The liquid radwaste monitor and the associated monitor setpoint are not used as part of any safety related system. The liquid radwaste monitor setpoint is not considered in any evaluation of the probability of occurrence of an accident. Accordingly, changing the monitor setpoint will not increase the consequences an accident evaluated previously in the LBDs.

2.6.3.11
<u>SCN 95-041</u>

This SCN provided for clarification requirements for containment atmosphere mixing system and addresses minor inconsistencies in regard to the containment cooling system.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. A new analysis shows that atmospheric mixing will be provided by operation of a single head area fan which will satisfy the requirement to prevent formation of pockets of combustible gas mixtures after a LOCA. This is consistent with the current licensing basis. Operation of the other seven recirculation fans are, therefore, unnecessary for post-LOCA containment atmosphere mixing. Accordingly, the consequences of a previously evaluated accident will not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.3.12
<u>SCN 95-043</u>

This allowed for the continued release of batches to the liquid effluent line when the radwaste liquid effluent monitor has been out of service for greater than 30 days.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. The liquid radwaste monitor is not used as part of any safety related system. The liquid radwaste monitor is not considered in any evaluation of the probability of occurrence of an accident. The FSAR specifically excludes the liquid radwaste effluent monitor from the group of radiation monitors important to plant safety. Therefore, changes to the monitor inoperability to greater than 30 days will not increase the probability of occurrence or consequences of an accident evaluated previously in the LBDs.

2.6.3.13
<u>SCN 95-044</u>

This SCN provided for the reduction in the surveillance frequency of some fire system inspections, revision of the fire protection engineer qualification description, removal of the surveillance-related NFPA code deviations, discontinuance of fire damper drop testing during design air-flow, and grammatical improvements.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. The reduction in surveillance frequency is performance-based in that the results of past surveillances were reviewed to determine if the frequencies are appropriate. Although some surveillance frequencies appear appropriate, many are excessive and in a few cases not required. The changes do not lower the ability of safety systems to perform during accident conditions. Fire protection systems are not related to any initiators of previously analyzed accidents. Other changes consist of removing the NFPA code deviations related to surveillance, elimination of fire damper drip testing during air flow conditions and changes to Fire Protection Engineer qualifications. The changes will not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.3.14
<u>SCN 95-045</u>

This SCN provided for inclusion of Biometric Hand Geometry Access control devices, deleted use of serially numbered site badges and allowed for badges and keycards to be taken off site.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. The process of granting unescorted access to the protection area is not directly associated with the design, function or operation of the plant equipment. Thus, the probability of an accident occurrence cannot be impacted by the elimination of the picture badge issuance, collection and storage functions. Therefore, this does not increase the consequences of an accident evaluated previously evaluated in the LBDs.

2.6.3.15
<u>SCN 95-053</u>

This SCN provided for revision of staffing levels for the Fire Brigade positions requiring a minimum of three Operations Personnel by deleting the requirement of Operations personnel and simply requiring that the Fire Brigade Leader and two members be knowledgeable of plant fire safe shutdown systems.

This change does not lower the ability of safety systems to perform during accident conditions and does not increase challenges of safety systems to perform below their design basis without compensating effects. In addition, this change does not involve any plant physical modifications or changes in equipment operations. The proposed change will not increase the probability or consequences of an accident evaluated previously in the LBDs.

2.6.3.16
<u>SCN 95-059</u>

This SCN provided for consolidation of Fire Areas R-17 and R-19 in the Reactor Building into one fire area.

These changes do not lower the ability of safety systems to perform during accident conditions. Fire protection systems are not related to any initiators of previously analyzed accidents. The changes in fire area boundaries do not affect the operation or hazards of plant equipment beyond that previously evaluated and, therefore, will not increase the probability of licensing basis fire accidents. The changes will also not increase the consequences of occurrence of an accident evaluated previously in the LBDs.

2.6.3.17
SCN 95-060

This SCN provided for revision of the Emergency Plan by changing the Emergency Operations Facility Communications Center (EOFCC) to Security Communications Center (SCC), the Plant Emergency Team to Fire Brigade Team, the removal of position titles no longer used, and minor editorial changes.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this change. Renaming the EOFCC to SCC as a result of locating the functions of the EOFCC to other 24-hour staffed areas renders no reduction in function provided. Simplification of the title of the group performing emergency services, whether those services be first responder or fire protection or suppression, causes no reduction of the function provided. Therefore, the consequences of an accident as previously evaluated in the LBDs will not increase because the changes do not impact the evaluated accidents.

2.6.4 PROBLEM EVALUATIONS

The Plant Problems-Plant Problem Reports Procedures (PPMs 1.3.12 and 1.3.12A) provide instructions for the disposition and documentation of plant problems. Plant problems are documented on a Problem Evaluation Request (PER). Safety Evaluations were performed for the following PERs during 1995. In each case, it was determined that the disposition did not involve an Unreviewed Safety Question or represent a change to the Technical Specifications.

2.6.4.1
PER 293-1196

This PER documented a discrepancy pertaining to valve motor brake operability for several valves at degraded voltage conditions that was identified during NRC Inspection 93-23. As a result of further evaluation, it was determined that the original WNP-2 valve specifications required that safety-related motor operated valves be operable at 80 percent voltage. The valve suppliers did not meet the specifications on those valves with brakes. The original 10CFR50.59 review associated with the operability assessment for the PER was revised to reflect the results of brake release testing for High Pressure Core Spray (HPCS) Valve HPCS-V-4 that was completed during the 1995 R-10 Maintenance and Refueling Outage. The revised review supported the permanent "accept-as-is" PER disposition for leaving the brake installed on the motor for HPCS-V-4.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced due to the PER disposition. Continuing to utilize the HPCS-V-4 motor brake is acceptable based on subsequent testing where it was validated that the valve would operate at voltages below that calculated to occur during degraded conditions. Based on testing, it is not expected that the failure rate of the motor brake on the valve would increase due to operation at voltage levels below the manufacturer's recommended minimum 90 percent rated voltage. Operating the HPCS System with the motor brake causing the valve to operate below the manufacturer's recommended voltage is not a problem because testing has shown the brake to operate (release) at voltage levels below that expected during degraded conditions. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.2
PER 295-0029

This PER documented a situation where it was discovered during testing that the tubing block clamp installation nearest to Containment Atmosphere Control (CAC) System Level Transmitter CAC-LT-1B was not installed in accordance with design drawings. The disposition for this PER was permanent "accept-as-is."

It was concluded from the safety evaluation that the current configuration of the CAC-LT-1B low side tubing support does not affect the seismic qualification of CAC-LT-1B or CMS-MS-1B. which are mounted on the CAC skid independently and provide axial anchor points. With no affect on the CAC-LT-1B tubing integrity, the CAC-LT-1B instrument loop would be fully capable of performing its intended design safety function of maintaining normal CAC-MS-1B water levels and providing annunciation in the control room of abnormally high levels which could be indicative of instrument loop malfunction. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.3
PER 295-0159

This PER documented a situation where, following the shift of the Reactor Recirculation (RRC) System pumps to fast speed, Flow Control Valve RRC-V-60B did not immediately move from the minimum position. The probable cause was due to flow control valve ball deflection due to excessive differential pressure resulting in binding at axial bearing location. The safety evaluation allowed for increasing minimum flow control valve position to ten percent open to move the minimum position away from the maximum load conditions to avoid the binding problem when a pump is shifted to fast speed.

It was concluded from the safety evaluation that the activity would not increase the consequences of any previously evaluated normal or accident scenarios evaluated in the LBDs. Changing the position from the minimum position to ten percent open results in a flow change from about 2300 gpm to 3400 gpm at slow speed, and from 1300 gpm to about 1800 gpm at fast speed. This increased flow will have the effect of increasing the margin to safety boundary because the power level will change only slightly. Furthermore, the change will not challenge the bounding operating conditions assumed in the reload analysis for Cycle 11 and is also not expected to challenge the bounding license conditions for future cycle reload analyses because of the conservative assumptions used in the analyses. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.4
PER 295-0231

This PER documented a situation where it was discovered that the breaker controls for High Pressure Core Spray (HPCS) System Emergency Diesel Generator HPCS-DG-3 did not have a generator voltage buildup logic permissive for breaker closure. This condition was contrary to the General Electric standard design configuration and the description in the WNP-2 FSAR. The disposition for this PER was permanent "accept-as-is."

It was concluded from Supply System and General Electric evaluations that the diesel generator was operable without the voltage build-up permissive. In the safety evaluation, it was concluded that the consequence of having less than adequate diesel generator voltage during a design basis accident is the same whether the voltage build-up permissive is included or not. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.5
PER 295-0586

This PER documented a situation where, during the performance of Plant Procedure (PPM) 8.3.361, "ATWS-ARI Functional Test - Cold Shutdown," the as-found "implied" scram time for Control Rods 54-47 and 58-23 exceeded the acceptance criteria of 15 seconds. Actual time were 18 and 19 seconds respectively. This procedure was performed to satisfy the post-maintenance test requirements for scram solenoid pilot valves in which new diaphragm/o-ring material was installed during the 1995 R-10 Maintenance and Refueling Outage. The disposition for this PER was permanent "accept-as-is."

It was concluded from Supply System and General Electric evaluations that there was not a problem to extend start times of control rod motion and completion of rod motions following an Alternate Rod Insertion (ARI) initiation. It was concluded from the safety evaluation that ARI System is used as a protective feature against Anticipated Transient Without Scram (ATWS) scenarios and is not credited for mitigation against any design basis accident in the LBDs. (The ARI System is credited in the ATWS analysis for Anticipated Operational Occurrences.) However, the bounding events for ATWS assume loss of the ARI function. Furthermore, even with credit for ARI, the ATWS events are analyzed to occur without any fuel damage. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.6
PER 295-0639

This PER was initiated to document the results of a General Electric (GE) evaluation of jet pump restrainer bracket adjusting screw tack welds performed during the R-10 1995 Maintenance and Refueling Outage. The evaluation was performed as recommended by GE Service Information Letter 574. During the evaluation a total of 80 jet pump welds were inspected and only two failures were identified. The failures were associated with one tack weld on Jet Pump 5 and one tack weld on Jet Pump 14. The disposition for this PER was permanent "accept-as-is."

It was concluded from the safety evaluation that failure of one of the redundant tack welds on the restrainer bracket adjusting screw or tack welds would not affect the fission product inventory, release mechanism or ability to cool the core. Furthermore, the inside shroud injection systems were not affected and would continue to inject water on top of the core and provide cooling for the fuel assemblies. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.4.7
PER 295-1070

This PER documented a situation where a secondary containment bypass path was discovered through the Reactor Core Isolation Cooling (RCIC) System steam line to the main condenser through Steam Line Drain Valves RCIC-V-25 and RCIC-V-26. In the event of a failure or Motor Operated Turbine Steam Admission Valve RCIC-V-45 to open, valves RCIC-V-25 and RCIC-V-26 would remain open. No analysis had previously been performed for offsite and control room dose consequences for this particular bypass path (with no valves closed). The disposition of this PER was to revise operating procedures to require manual action to assure the valves are closed.

It was concluded from the safety evaluation that there would not be a problem with the revision to plant procedures to include manual closure of RCIC-V-25 and RCIC-V-26 upon initiation of the RCIC System concurrent with high drywell pressure (1.68 psig) and decreasing reactor pressure vessel level indication at or below Level 2 (-50 inches). The valves would by positioned by manually moving the switch to "closed." Valves RCIC-V-25 and RCIC-V-26 are steam line valves between the steam supply line and the main condenser. The valves are designed to close upon the opening of RCIC-V-45. The credited containment isolation valves for this system are RCIC-V-8, RCIC-V-63 and RCIC-V-76. Except for a small line break LOCA, these valves remain open for RCIC injection. Credit for manual initiation and isolation of the RCIC System has previously been taken for level control in the WNP-2 Emergency Operating Procedures. This action requires all isolations Emergency Core Cooling System initiations and emergency diesel generator initiations to have occurred. Once RCIC-V-25 and RCIC-V-26 are manually closed, they will continue to be in that configuration for the remainder of the accident. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.5 PLANT TESTS AND EXPERIMENTS

This section of the report covers WNP-2 Plant tests and experiments not described in the Safety Analysis Report as required by 10CFR50.59.

There were no tests or experiments performed under the provisions of 10CFR50.59 in 1995.

2.6.6 PLANT PROCEDURE CHANGES

The plant procedure control program requires that a 10CFR50.59 determination be made whenever a procedure is changed. This provides assurance that the change does not require a change to the Technical Specifications or involve an Unreviewed Safety Question. The following are summaries of those Plant Procedure (PPM) and Nuclear Operation Standard (NOS) changes for which safety evaluations were performed during 1995.

2.6.6.1
Revision of NOS-14, Operating Experience Review

The purpose of this standard is to ensure that maintenance, operations, and design experiences which apply to nuclear safety and plant reliability are received, assessed and utilized to enhance nuclear plant safety and to maximize plant availability. The revision to this NOS was administrative in nature and did not involve a physical plant modification. Responsibility for Independent Safety Engineering Group (ISEG); administering the operating experiences, nonconforming condition and corrective action process (PER); root cause determination and evaluating industry operating experience was reassigned to the Director, Regulatory and Industry Affairs. It was concluded from the safety evaluation that the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.6.2
Procedure Revision Form for PPM 1.3.36

This procedure establishes the minimum training requirements for personnel responding to emergencies, for fire watches and for First Responders. The revision to this PPM was for the purpose of allowing non-Operations Personnel, who are knowledgeable of plant fire safe shutdown systems, to occupy Fire Brigade positions.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure change. The change does not lower the ability of any safety system to perform during accident conditions and does not increase challenges of safety systems to perform below their design basis without compensating affects. Therefore, the activity would not increase the consequences of an accident evaluation previously in the LBDs.

2.6.6.3
Procedure Revision Form for PPM 1.10.4

This procedure provides instructions for ensuring that maintenance, operations, and design experiences which apply to nuclear safety and plant reliability are received, assessed and utilized to enhance nuclear plant safety and to maximize plant availability. The revision to this PPM was administrative in nature.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure change. It includes deleting Plant General Manager signature requirements on Operating Event Review actions, enables other organizations to perform reviews, defines responsibilities and defines how reviews are performed. Therefore, the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.6.4
Procedure Revision Forms for PPM's 4.12.4.1 and 4.12.1.1

These procedures provides instruction for Control Room Fire, Control Room Evacuation and Remote Cooldown. The revisions to these procedures were necessary to remove interim Operator actions required because of fire safe shutdown design and protection deficiencies, as well as to simplify and make consistent fire-related Operations procedures with Emergency Operating Procedures and Generic Letter guidance.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure change. These changes do not affect system equipment operation or function of Operator response to design basis events. Ensuring that procedures account for potential fire-related effects reduce the potential for equipment malfunctions. Therefore, it was concluded that the activity would not increase the consequences of an accident evaluated previously in the LBDs.

2.6.6.5
Procedure Revision Forms for PPM's 5.0.10 and 5.1.1

These procedures provide instruction for Emergency Operating Procedure for Reactor Pressure Vessel (RPV) Control and the Flowchart Training Manual Procedure. The implementing activity is a change to direct the Operator to inhibit actuation of the Automatic Depressurization System (ADS) by using the ADS Inhibit Switch instead of inhibiting ADS by resetting the ADS timer.

It was concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of these procedure changes. The proposed changes would only have an affect if plant conditions are indicated to be such that PPM 5.1.1 has been "entered" and has been executed to the stage that the Operator has determined that RPV Level cannot be maintained above +13 inches. At present, when this stage has been reached, the Operator is instructed to inhibit ADS by resetting the time. Further, the Operator is required to continually reset the timer such that ADS remains inhibited. Procedure 5.1.1 does not, at any stage, call for the ADS to be actuated. Thus, it is clear that once execution of this procedure has commenced the ADS function is consciously nullified. The proposed change would permit this nullification to be effected through another means that involves only the same logic circuits. Therefore, the proposed changes will not increase the consequences of an accident evaluated previously in the LBDs.

2.6.6.6
Procedure Revision Form for PPM 7.4.0.5.25

This procedure provides instructions for performing a pressure test on piping and components to satisfy ASME Inservice Inspection and leakage pressure testing requirements. This procedure changes the pressure at which shutdown cooling is taken off-line (or put back in service), includes further guidance on required procedure actions and incorporates miscellaneous administrative changes.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure change. The test pressure is the normal operating pressure for power uprate conditions and is within analyzed limits for all allowable temperature ranges. The temperature of the reactor vessel and associated piping will be maintained above the nil-ductility temperature limit to ensure no brittle fracture. The rate of pressurization or depressurization will not increase the possibility of a different type of malfunction of equipment important to safety then previously evaluated in the LBDs. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.6.7
Procedure Revision Form for PPM 7.6.0.8

This procedure provides instructions for Post Accident Sampling System leakage surveillance. The revision to this PPM was to expand the scope of the Post Accident Sampling Leakage Surveillance to perform leak inspection on the atmospheric portion of the PASS system.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure change. The revision maintains double-valve isolation of containment while opening the sample line to the test cart for leak testing. The PASS system, other than the containment isolation valves, does not provide any safety related function for accident prevention or mitigation. The failure of the PASS sample lines or sample station is not an initiating event for any accident scenario. Therefore, there is no increase in the probability of occurrence of an accident previously evaluated in the LBDs.

2.6.6.8
Procedure Revision Form for PPM 8.3.341

This is a new procedure which provides instructions for performing in-situ operability testing on Fuel Pool Cooling (FPC) System Filter Demineralizer Inlet Isolation Valve FPC-V-173.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. The primary intent of this procedure is to satisfy the one-time testing recommendations of NRC Generic Letter 89-10, as delineated in WNP-2's "Motor Operated Valve Program Plan", but may also be used for future periodic or post-maintenance testing. Therefore, this test does not create the possibility of an accident of a different type than any evaluated in the LBDs.

2.6.6.9
Procedure Revision Form for PPM 8.3.342

This is a new procedure which provides instructions for performing in-situ operability testing on Residual Heat Removal (RHR) System Reactor Head Spray Valve RHR-V-23.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. The primary intent of this procedure is to satisfy the one-time testing recommendations of NRC Generic Letter 89-10, as delineated in WNP-2's "Motor Operated Valve Program Plan", but may also be used for future periodic or post maintenance testing. Therefore, this test does not create the possibility of an accident of a different type than any evaluated in the LBDs.

2.6.6.10
Procedure Revision Form for 8.5.11

This is a new procedure developed to provide process controls and final inspection criteria to effectively manage chemical decontamination of the Reactor Water Cleanup (RWCU) System by means of the CITROX process.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. The decontamination solution will be contained in the RWCU System, hoses and vendor equipment. There will be no detrimental affects to either material or components in the RWCU system or adjoining systems and the controls on air, water and electrical power and on controlling spills and leaks from the system. Therefore, the chemical decontamination will not increase the consequences of a malfunction of equipment important to safety previously evaluated in the LBDs.

2.6.6.11
Procedure Revision Form for 8.5.12

This is a new procedure developed to provide instructions for the chemical cleaning of the two-inch portion of the High Pressure Core Spray (HPCS) System loop of the Service Water (SW) System which provides cooling water to the HPCS pump room cooler.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. There is no potential for this chemical cleaning test to impact any equipment that would be relied upon at the time of the chemical cleaning test to perform its safety function. There is no impact to any structure, system or component during this chemical cleaning test that would be necessary to mitigate the consequences of a malfunction of equipment important to safety evaluated previously in the LBDs. Therefore, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.6.12
Procedure Revision Form for 10.3.3

This procedure provides instruction for Drywell Head removal and replacement. This procedure revision provides for an increased area of safe load path for the Drywell Head.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. Moving the drywell head over the proposed safe load path is bounded by the safe load paths approved for the Reactor Pressure Vessel (RPV) head and upper dryer/separator pool shield plug. Either of these components weigh more than the drywell head. Therefore, the margin of safety as defined in the basis for the LBDs is not reduced. Accordingly, the activity would not increase the probability of occurrence or the consequences of an accident evaluated previously in the LBDs.

2.6.6.13
Procedure Revision Form for 14.5.3

This procedure provides instruction for implementing Safeguards Compensatory Measures. This procedure revision provides for several enhancements to vital area doors and administrative changes.

It is concluded from the safety evaluation that an unreviewed safety question is not introduced as a result of this procedure. No change to any security protection equipment is required (i.e., hardware or software changes to the security system computer or vital area portals would not be required). The ability to protect vital equipment target sets continues to be maintained by prompt response to a vital area door alarm when an unauthorized access attempt is detected by the security system. The consequences of malfunction of equipment is not increased as a result of this change. Therefore, this change does not increase the probability of occurrence of an accident evaluated previously in the LBDs.

2.6.7 Miscellaneous

This section covers other plant activities for which a 10CFR50.59 Safety Evaluation was performed during 1995.

2.6.7.1 Computer Change Request TE-93-003

This computer change request provided for modification of the WNP-2 Core Stability Monitoring Program (ANNA) code, alarm headers and displays to allow for human factor improvements. The changes included modification of the alarm header display to show the decay ration and peak-to-peak values at all times, data smoothing of decay ratio output from the auto-correlation calculation, and detection and elimination of incoming data blocks that contain spikes.

It was concluded from the safety evaluation that the activity would not increase the probability of occurrence of an accident evaluated previously in the LBDs. The modifications made to the ANNA Software System are designed to improve the ability of plant operations personnel to accurately identify any potential plant instabilities. The enhancements of alarm headers and displays amplify the visibility of required information. The use of data smoothing and elimination of spiked data blocks eliminates both abnormally high and low false decay ratio spikes (and their corresponding false alarms), allowing the system to report more accurate data. None of these factors can lead to an increase in the consequences of the occurrence of an accident previously evaluated in the LBDs. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.2 COLR 95-11

This safety evaluation allowed for implementation of the WNP-2, Cycle 11, Core Operating Limits Report (COLR).

It was concluded from the safety evaluation that the activity would not increase the probability of an accident evaluated previously in the LBDs. Operation of Cycle 11 within the thermal limits defined in COLR 95-11 does not increase the consequences of the analyzed anticipated operational occurrences or accidents because the mechanical, thermal hydraulic and LOCA design criteria imposed on the fuel to protect it during these events are met. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.3
Licensee Controlled Specification 1.3.3.1

This safety evaluation allowed for relocation of the Technical Specification requirements for post accident monitoring instrumentation to Section 1.3.3.1 of the Licensee Controlled Specification (LCS) Manual.

It was concluded from the safety evaluation that all changes were administrative in nature. On March 27, 1995 the NRC approved a Supply System request that the requirements for Safety/Relief Valve (SRV) position indication requirements be removed from the Technical Specifications and be relocated to licensee controlled documents. The SRV position indication instrumentation is a non-intrusive design that does not affect operation of the SRV. The instrumentation provides only indication and alarm functions. There are no control or accident mitigation features. Furthermore, the SRV position indication does not impact the conditions, assumptions or conclusions of the transient analysis for a stuck open SRV and, as such cannot initiate the event. Because the SRV position indication instrumentation is not an event initiator, relocation of the operability and surveillance requirements to the LCSs will not increase the probability of the previously analyzed event. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.4
Licensee Controlled Specification 1.3.7.2

This safety evaluation allowed for relocation of the Technical Specification requirements for seismic instrumentation to Section 1.3.7.2 of the Licensee Controlled Specification (LCS) Manual.

It was concluded from the safety evaluation that all changes were administrative in nature. On August 22, 1994 the NRC approved a Supply System request that the requirements for seismic instrumentation be removed from the Technical Specifications and be relocated to licensee controlled documents. The changes do not adversely affect the function or design requirements of the instruments as specified in the LBDs, periodic surveillance requirement, allowable outage times, information available to the operators or operator actions if an earthquake occurs, or information reported to the NRC. The proposed changes will not increase the probability of occurrence of an accident evaluated previously in the LBDs. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.5
Licensee Controlled Specification 1.3.7.2

This safety evaluation allowed for the revision to Section 1.3.7.2 of the Licensee Controlled Specification (LCS) Manual. Specifically, the section was revised to change required compensatory measures to initiate a Problem Evaluation Request (PER) rather than submit a special report to the Vice President, Nuclear Operations when the instrumentation channels are not returned to operable status within 30 days.

It was concluded from the safety evaluation that the changes do not modify the seismic monitoring system or instrumentation. The seismic monitoring system does not perform a safety function but provides information to determine design impact post accident. The seismic monitoring system is an indication only system and has no trip functions or automatic actuations. The accelerometers are not accident initiating devices. Therefore, revision of compensatory actions on instrument inoperability will neither increase the probability of occurrence of an accident nor create an unreviewed safety question.

2.6.7.6
Work Order PM 29

This safety evaluation allowed for the placement of staging devices and new core shroud head bolts in the equipment pool, removal of the existing shroud bolts and installation of the new bolts.

It was concluded from the safety evaluation that the lifting devices and staging equipment would not increase the probability of an accident during a seismic event. A load drop on the spent fuel racks and fuel assemblies is bounded by FSAR analysis. Furthermore the work was to be accomplished in accordance with approved procedures and standards. Safe load paths were also to be used to ensure that the loads did not pass over equipment necessary for the safe operation of the plant. The proposed activity will not increase the probability of occurrence of an accident evaluated previously in the LBDs. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.7
Design Specification 15B.1

This safety evaluation allowed for the revision to Design Specification 15B.1 to reflect weld inspection requirements of the ANSI B31.1 Power Piping Code and, thereby, eliminate the augmented (i.e., additional) inspections that were imposed by the WNP-2 Architect engineer and Supply System for production quality control during the plant construction phase.

It was concluded from the safety evaluation that the activity would not increase the probability of an accident evaluated previously in the LBDs. Nondestructive examination (NDE) requirements imposed on non-safety system piping welds are not a basis, or parameter, which is applied in any safe shutdown or offsite dose analysis. All pipe break locations are postulated on the basis of high stress points of constrained flexibility. Alternately stated, no new break location can be created , nor is the probability of any break location increased since pipe breaks are either non-mechanistically postulated or based on stress field information which has no connection to NDE processes which were applied during the joint fabrication. Therefore, implementation of this activity would not create an unreviewed safety question.

2.6.7.8
<u>Supply System POWERPLEX Input for Cycle 11</u>

This safety evaluation allowed for the operation of the POWERPLEX Core Monitoring Software System, with Supply System input, for Cycle 11.

It was concluded from the safety evaluation that the activity would not increase the probability of an accident evaluated previously in the LBDs. The proposed activity is to use Supply System supplied input equivalent to that of the fuel vendor. Implementation of this activity will not change the ability to accurately monitor the operating limits of the core. Because of adequate review of core follow and core monitoring results for operating Cycles six through ten and testing of the Cycle 11 input, this activity will not change the ability to accurately monitor the core operating limits. Therefore, implementation of this activity would not create an unreviewed safety question.

2.7 REPORT OF DIESEL GENERATOR FAILURES

This section of the report contains information regarding diesel generator failures, valid and non-valid, in accordance with the requirements of WNP-2 Technical Specification 4.8.1.1.3.

There were no valid or non-valid load demand failures in 1995 for the three emergency diesel generators.