WISCONSIN ELECTRIC

POWER COMPANY

POINT BEACH NUCLEAR PLANT

UNITS 1 AND 2

ANNUAL RESULTS AND

DATA REPORT

1994

U.S. Nuclear Regulatory Commission
Dockets Nos. 50-266 and 50-301
Facility Operating License Nos.
DPR-24 and DPR-27

PREFACE

This Annual Results & Data Report for 1994 is submitted in accordance with Point Beach Nuclear Plant, Unit Nos. 1 and 2, Technical Specification 15.6.9.1.B and filed under Docket Nos. 50-266 and 50-301 for Facility Operating License Nos. DPR-24 and DPR-27, respectively.

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I. INTRODUCTION

The Point Beach Nuclear Plant, Units 1 and 2, utilize identical pressurized water reactors rated at 1518 MWt each. Each turbine-generator is capable of producing 497 MWe net (524 MWe gross) of electrical power. The plant is located ten miles north of Two Rivers, Wisconsin, on the west shore of Lake Michigan.

II. HIGHLIGHTS

UNIT 1

Highlights for the period January 1, 1994, through December 31, 1994, included a 28-day refueling/maintenance outage. Major work items included reactor vessel head inspection, "A" steam generator loose parts inspection, steam generator sludge lancing, cavity cooler cleaning, removal of the circuits for the LO-LO boric acid storage tank level safety injection auto transfer to the refueling water storage tank, replacement of safeguards sequence timing relays, adjust time delays on degraded grid voltage relays, modified safety injection supports as part of Bulletin 79-14 upgrades, resurface turbine governor valve seats, replace 32 safety-related molded-case circuit breakers, 4-rotor limit switches installed on 13 valve motor operators, as-built electrical walkdowns of 4160 Vac and 480 Vac switchgear, and as-built electrical tracing of reactor protection and safeguards system.

Unit 1 operated at an average capacity factor of 91.9% (MDC net) and an electrical/thermal efficiency of 32.4%. The unit and reactor availability were 92.1% and 92.7%, respectively. Unit 1 generated its 79 billionth kilowatt hour on January 12, 1994; its 80 billionth kilowatt hour on May 6, 1994; its 81 billionth kilowatt hour on July 26, 1994; and its 82 billionth kilowatt hour on October 16, 1994.

UNIT 2

Highlights for the period January 1, 1994, through December 31, 1994, included a 38-day refueling/maintenance outage. Major work items included amptector upgrades, residual heat removal pump rotor replacement, 4-rotor limit switch upgrades, main feedwater check valve replacements, reactor heat shield installed, SI-854A&B internals replacement, Gai-tronics upgrade, G04 emergency diesel generator tie-in work, reactor coolant pump seal water flow transmitter replacement, safeguards sequence timing relay replacements, control rod drive mechanism control current timing modification, degraded grid voltage relay work, steam generator blowdown heat exchanger replacement, and containment service water pump support work as part of continued Bulletin 79-14 upgrades.

Unit 2 operated at an average capacity factor of 88.3% (MDC net) and an electrical/thermal efficiency of 32.3%. The unit and reactor availability were 89.4% and 89.6%, respectively. Unit 2 generated its 80 billionth kilowatt hour on March 21, 1994; its 81 billionth kilowatt hour on June 11, 1994; and its 82 billionth kilowatt hour on September 1, 1994.

III. AMENDMENTS TO FACILITY OPERATING LICENSES

During 1994, there were 16 amendments issued by the U. S. Nuclear Regulatory Commission to Facility Operating License DPR-24 for Point Beach Nuclear Plant Unit 1 and DPR-27 for Point Beach Nuclear Plant Unit 2. The license amendments are listed by date of issue and summarized below:

Amendment 144 to DPR-24, Amendment 148 to DPR-27, January 3, 1994: The amendments modified TS 15.3.10 (Control Rod and Power Distribution Limits.) The changes also modified TS 15.3.10.A.5 by removing its applicability when the reactor is in hot shutdown.

Amendment 145 to DPR-24, Amendment 149 to DPR-27, January 27, 1994: The amendments split TS 15.3.1.E.2 that defined the allowable limits of chloride and fluoride in the reactor coolant, into two individual LCOs, thus clarifying the reactor coolant chemistry limitations. Additionally, the amendments added a 24-hour hot shutdown action statement to the reactor coolant impurity limit LCOs. The amendments also modified the corresponding TS Bases.

Amendment 146 to DPR-24, Amendment 150 to DPR-27, January 27, 1994: The amendments revised TS 15.6 to update several position titles, modified the composition and duties of the Manager's Supervisory Staff, and removed a redundant review of the facility fire protection program implementing procedures.

Amendment 147 to DPR-24, Amendment 151 to DPR-27, April 20, 1994: The amendments added operating conditions and LCOs for the atmospheric steam dump valves, the crossover steam dump system, the turbine stop and governor valves, and various turbine overspeed protection features. Additionally, the change revised the surveillance requirements for the auxiliary feedwater system. The amendments also added explanatory text to the Bases for TS 15.3.4 and 15.4.8.

Amendment 148 to DPR-24, Amendment 152 to DPR-27, May 11, 1994: The amendments revised TS 15.3.7, 15.4.6 and Table 15.4.1-2. The revisions incorporated items identified during a comparison of the accident analyses in the FSAR and the LCO and surveillance sections of the Technical Specifications. The changes added systems or equipment required by the accident analyses. Testing requirements for the EDGs were revised to eliminate the daily testing requirement when one EDG is inoperable.

Amendment 149 to DPR-24, Amendment 153 to DPR-27, August 16, 1994: The amendments modified TS 15.3.1.A.3 related to decay heat removal system requirements and its Basis to improve its clarity.

Amendment 150 to DPR-24, Amendment 154 to DPR-27, August 25, 1994: The amendments changed the inservice test frequency of the safety injection pumps, residual heat removal pumps and containment spray pumps from monthly to quarterly. Also, the amendments added the administration of the inservice testing program to TS 15.4.2. The amendments added requirements to verify the containment sump suction is not blocked and to verify on a monthly basis, valve alignments of the emergency core cooling system and containment cooling systems.

Amendment 151 to DPR-24, Amendment 155 to DPR-27, August 26, 1994: The amendments are administrative only and change all references of rod position in the Technical Specifications to units of "steps" rather than "inches". The amendments revised the Basis for TS 15.3.10 by clarifying the definition of "fully withdrawn" as it concerns rod cluster control assemblies.

Amendment 152 to DPR-24, Amendment 156 to DPR-27, September 23, 1994: The amendments revised the Technical Specifications to establishes the requirements for the electrical systems such that the Technical Specification will provide the appropriate guidance for all interim configurations and the final configuration for the two additional EDGs being installed.

Amendment 153 to DPR-24, Amendment 157 to DPR-27, September 23, 1994: The amendments modified TS 15.3.4 and 15.3.7 to increase the allowed outage times for one motor-driven auxiliary feedwater pump and for the standby emergency power for the Unit 1 Train B 4160 V safeguards bus (A06) from 7 to 12 days. The amendments also modified TS 15.3.3 to provide the clarification that the service water pump (P32E) operating with power supplied by the alternate shutdown system is operable from offsite power. The changes are a one-time extension of specific allowed outage times.

Amendment 154 to DPR-24, Amendment 158 to DPR-27, September 29, 1994: The amendments modified TS 15.3.7 to include an allowed outage time for one of the four connected station battery chargers and subsequent shutdown requirements.

Amendment 155 to DPR-24, Amendment 159 to DPR-27, September 30, 1994: The amendments revised TS 15.3.1.A.5 and 15.3.15 and Table 15.4.1-1. The changes specified more stringent LCOs and surveillance requirements for pressurizer power-operated relief valves and block valves. The changes conform to the NRC plan for resolution of Generic Issues 70 and 94 as conveyed in Generic Letter 90-06.

Amendment 156 to DPR-24, Amendment 160 to DPR-27, October 28, 1994: The amendments revised TS 15.3.1.G to reduce the Unit 2 reactor coolant system raw measured total flow rate and operating pressure, modified TS 15.2.3.1.B to increase the required reduction in the ΔT trip setpoint, and modified TS Figure 15.2.1-1 to reflect new reactor core safety limits, all for Unit 2 only.

Amendment 157 to DPR-24, Amendment 161 to DPR-27, December 8, 1994: The amendments extensively revised TS 15.3.5 and 15.4.1 that specify requirements for the instrumentation and safety circuits necessary to ensure reactor safety and provide for the automatic initiation of the engineered safety features.

Amendment 158 to DPR-24, Amendment 162 to DPR-27, December 12, 1994: The amendments modified TS 15.3.2 by eliminating the necessity for high concentration boric acid and removing the operability requirements for the associated heat tracing.

Amendment 159 to DPR-24, Amendment 163 to DPR-27, December 21, 1994: The amendments modified TS 15.3.3 by incorporating allowed outage times similar to those contained in NUREG-1431 and by clarifying the operability requirements for the service water pumps. The changes also clarified the completion times for placing a unit in hot or cold shutdown, if an LCO cannot be met.

IV. 10 CFR 50.59

PROCEDURE CHANGES

1. AOP-0.1, (Major), Declining Frequency on 345 kV Distribution System, Revision 0. (New Procedure)

   AOP-0.1 is an abnormal operating procedure that provides guidance to operating personnel in the unlikely event of declining frequency on the 345 kV transmission and distribution system.

   Summary of Safety Evaluation: Two scenarios involving degraded frequency on the transmission and distribution system exist in the procedure. Section 4.0 provides separate responses to address an abrupt total collapse of system frequency and a gradual deterioration of system frequency at a rate approaching -0.5 Hz/min.

   Once system frequency drops to 58 Hz, a total collapse of the transmission and distribution system is imminent. Total collapse constitutes a loss of offsite power. Attempts to reduce loading on the generating units only serves to expedite a total collapse and must not be undertaken.

The procedure is prepared in accordance with MAIN Guide 1B "Operating Procedure During Generating Capacity Deficiencies Causing Declining System Frequency or Separation." The guide requires that electrical generators be manually removed from the grid after 30 seconds of operation at ≤58 Hz.

Westinghouse warranty requirements limit lifetime off-frequency turbine operation to 60 minutes maximum at 59.5 to 58.5 Hz and only 10 minutes at 58.5 to 56 Hz. The limits assure that crack propagation of low pressure turbine blading does not continue to the point of blade root severance with tangential missile generation. Although the Unit 2 turbine generator is the most susceptible to experiencing this type of damage over time, torsional resonance peaking occurs on both units at 1784 rpm; ~59.467 Hz. Continuous parallel operation between 1745 and 1795 rpm should be minimized to avoid this type of damage.

Departure from nucleate boiling ratio (DNBR) in the reactor core is assured by an underfrequency trip of both reactor coolant pump (RCP) supply breakers. This actuates the reactor protection system and generates an immediate reactor trip on low RCS flow. Power generation is terminated prior to further degradation of RCS flow by declining frequency. DNBR trends in a conservative direction as power decays away rapidly, while RCS flow decays relatively slow after opening of the RCP breakers due to the inertia of the RCP flywheels. This combination eliminates DNB concerns.

The automatic protection scheme prevents serious motor damage during a major frequency anomaly by removing the power supply prior to the onset of insulation overheating, degradation and failure. However, the extent of rapid heatup of the main generators is unknown. This potential for damage can be avoided, but only by timely manual separation of the main generators from the grid.

The RCP underfrequency setpoints remain unchanged as described in the Technical Specifications. The AOP only provides supplementary precautionary actions for the operators prior to the underfrequency trip. (SER 94-018)

2. AOP-1C, (Major), Cooldown to Cold Shutdown with Reactor Leak, Revision 0. (New Procedure)

Summary of Safety Evaluation. The procedure contains a method to cooldown the plant with primary leakage which may be used during either a RCS leak or a steam generator tube leak. Surveillance testing is postponed until plant conditions stabilize to allow for a timely shutdown during accident conditions. Normal shutdown procedures address testing of PORvs and Unit 2 SG pressure test.

TS Table 15.4.1-1 specifies the PORVs be tested prior to placing the low temperature overpressure protection system in service. AOP-1C directs placing LTOP in service prior to completion of testing if plant conditions are appropriate. The Unit 2 SG pressure test is not performed per this procedure because this helps expedite the required shutdown. The SG pressure test could be performed after plant conditions have stabilized. (SER 94-063)

3. CSP-Z.1, Unit 1 and Unit 2, (Major), Response to High Containment Pressure, Revision 7. (Temporary)

CSP-Z-3, Unit 1 and Unit 2, (Major), Response to High Containment Radiation Level, Revision 6. (Temporary)

ECA-0.0, Unit 1 and Unit 2, (Major), Loss of all AC Power, Revision 11. (Temporary)

ECA-0.2, Unit 1 and Unit 2, (Major), Loss of all AC Power Recovery with SI Required, Revision 9. (Temporary)

EOP-0, Unit 1 and Unit 2, (Major), Reactor Trip or Safety Injection, Revision 14. (Temporary)

The revision adds a response not obtained (RNO) substep to the containment isolation step to shut

manual valves SC-946 and SC-956C, if containment isolation valve SC-966C fails to shut.

Summary of Safety Evaluation: The change decreases the radiological release from containment in the event of an accident. Since containment isolation valve SC-955 is not missile protected, the change ensures that manual valves SC-946 and 956C are shut to isolate containment Penetration 28a if the second containment isolation valve (SC-966C) fails to shut. The change supports JCO 94-01 to place containment Penetration 28a in service to allow continuous use of the failed fuel monitor. (SERs 89-029-05, 89-030-04, 88-091-11, 89-031-07, 88-084-11)

4. EOP Setpoint Usage of G.3 and G.2 instead of G.11. This guidance is provided in accordance with Westinghouse Owners Group Emergency Response Guidelines, Revision 1B.

Summary of Safety Evaluation: Westinghouse Owners Group (WOG) Emergency Response Guidelines direct the use of narrow range steam generator (SG) level just on scale with instrument inaccuracies to specify entry to the heat sink status tree. Current procedures use a plant-specific setpoint (EOPSTPT G.11) for wide range steam generator levels of 200". This deviation is justified on the basis that narrow range is not a qualified instrument and 200" is a sufficient level to provide operators with time to align alternate sources of auxiliary feedwater. Since plant narrow range SG level instruments are qualified, this deviation is no longer justified. This revision uses the values specified in the WOG ERGs which are 28% (EOPSTPT G.3) for adverse conditions and 8% (EOPSTPT G.2) for normal uncertainties. (SER 94-067)

5. EOP-1, Unit 1 and Unit 2, (Major), Loss of Reactor or Secondary Coolant, Revision 14. (Permanent)

EOP-1.2, Unit 1 and Unit 2, (Major), Small Break LOCA Cooldown and Depressurization, Revision 9. (Permanent)

The revision moves steps to ensure the opening of safety injection (SI) core deluge valves (SI-878A&C) within 4 hours and establishes high head core deluge within 14 hours.

Summary of Safety Evaluation: The revision removes the high head core deluge lineup. Core deluge is provided during a large-break LOCA by the residual heat removal (RHR) pumps since RCS pressure for a large-break LOCA is less than the shutoff head for the RHR pumps. During a small-break LOCA core deluge is provided by the high head SI pumps for the higher RCS pressure.

Opening of the high head core deluge valves during a large-break LOCA results in runout of the RHR pump when providing for both the high and low head core deluge paths. Since core deluge is provided by the low head path, the high head path is not aligned. This revision corrects the procedural deficiency. Runout of the RHR pump during a small-break LOCA is not a concern since the RHR discharge head is less than RCS pressure and the low head core deluge path is not active. (SERs 88-087-13, 88-087-14)

6. EOP-1.2, Unit 1 and Unit 2, (Major), Small Break LOCA Cooldown and Depressurization, Revision 9. (Permanent)

The revision includes possible manual actuation of the containment spray system. This ensures proper containment sump pH for a small break LOCA. This function remains a TSC function and is specifically included in this revision as a verification step.

Summary of Safety Evaluation: Detailed considerations are provided for the TSC to decide if manual actuation of containment spray is needed for proper containment sump pH based upon information contained in Westinghouse Nuclear Safety Advisory Letter NSAL-93-016. Guidance for containment sump pH is contained in EOP-1.3, "Transfer to Containment Sump Recirculation," that states, "Consult with TSC to Determine if NaOH Should be Added to Containment." This step is applicable to a

LOCA where containment spray is not automatically initiated. The step is not sufficient to provide proper detailed considerations necessary for the TSC if containment spray needs to be actuated for small break LOCA NaOH addition.

Since mar al actuation of containment spray for a small-break LOCA is equivalent in equipment operation and functions as an automatic actuation of containment spray for a large break LOCA, no unreviewed safety question is presented by this change. (SER 89-037-08)

7. EOP-1.3, Unit 1 and Unit 2, (Major), Transfer to Containment Sump Recirculation, Revision 12. (Permanent)

The change identifies a large-break LOCA and eliminates the refueling water storage tank (RWST) level hold, except for the 28% level hold. This allows more time for establishing containment sump recirculation.

Summary of Safety Evaluation: The revision instructs that one containment spray (CS) pump, residual heat removal (RHR) pump, and safety injection (SI) pump be secured to slow the depletion of RWST. This provides more time to establish containment sump recirculation. The verification step of 1000 gpm flow through containment accident fan coolers is deleted. The component cooling water (CC) heat exchanger lineup is revised to remain within the limits identified in OP-6A, "Operation of Component Cooling System." Transitions to EOP-1.4, "Transfer to Containment Sump Recirculation, One Train Inoperable," are deleted. Appendices are added to specifically address malfunctions of each train. An appendix also lists required local actions for PAB operators to establish containment sump recirculation. The containment sump recirculation lineup is revised to simplify valve operation sequence and minimize the amount of time needed to establish containment sump recirculation. The CS lineup during recirculation phase is revised so CS only occurs when RHR suction is aligned to the RWST.

Appendices G and H provide train-specific details necessary to establish recirculation for each train malfunction. Appendices E and F provide a train-specific method for establishing recirculation when an equipment malfunction results in loss of recirculation but not injection. This reduces the potential for miscommunication because the PAB operator has written instructions to perform actions as directed by the control room. This revision includes another method of establishing containment sump recirculation by securing Train A SI; establishing Train A SI suction from RHR; and, securing Train B for lineup as recirculation. Once Train B is aligned as containment sump recirculation, Train A is secured. Recirculation is then provided by both trains through the low head core deluge and the high head cold leg injection paths. This method is recommended in NRC SER 12/24/74 that addresses boron precipitation concerns. Securing a train of SI during valve lineups provides a slower depletion rate of the RWST since only one train is injecting at a time. This prevents a loss of core cooling due to depletion of the RWST before the recirculation lineup is completed. (SERs 88-089-13, 88-089-14)

8. EOP-1.3, Unit 1 and Unit 2, (Major), Transfer to Containment Sump Recirculation, Revision 12. (Temporary)

The revision includes administrative changes that do not affect the procedure intent. Changes to core cooling steps are improved to better reflect the intent of these steps instead of relying upon operator memory and training.

Summary of Safety Evaluation: The core cooling steps verify that the only injection path is not secured. Indication may not be instantaneous. The steps become continuous action steps and provide assistance in determining adequate core cooling. The changes prevent a hold on these steps when operators consider the intent and help ensure successful transfer to containment sump recirculation before depletion of the RWST level. (SER 88-089-015)

9. EOP-1.3, Unit 1 and Unit 2, (Major), Transfer to Containment Sump Recirculation, Revision 13. (Permanent)

The revision incorporates operator feedback, corrects the format to meet writer's guide requirements, provides specific detail to reflect intent of steps, and improves procedure implementation.

Summary of Safety Evaluation: The revision restores Train A injection if Train A recirculation is not available. This allows Train B recirculation to be aligned without an unnecessary shift. The change allows shifting a train to recirculation with the opposite train injecting while the opposite train is available for injection, but not recirculation.

A change to EOPSTPT V.8 is addressed in SER 94-066. The basis for this setpoint is changed from the low spray additive tank alarm to a change in spray additive tank level corresponding to the optimum containment sump pH.

A change to foldout page for EOP-1 series for the heat sink red path is made and addressed via SER 94-066. The SG wide range level of 200" is replaced by a narrow range level of [28%] 8% since a deviation from the Westinghouse Owners Group ERGs is no longer required. (SER 94-065)

10. EOP-1.4, Unit 1 and Unit 2, (Major), Transfer to Containment Sump Recirculation, One Train Inoperable, Revision 12. (Permanent)

The procedure is canceled with portions of the procedure moved to EOP-1.3.

Summary of Safety Evaluation: Cancellation of EOP-1.4 does not represent an unreviewed safety question and does not require a change to the Technical Specifications. The method of establishing containment sump recirculation is included in EOP-1.3. Changes in the containment sump recirculation lineup are addressed in SER 88-089-14. (SERs 89-100-13 and 89-100-14)

11. EOPSTPT V.8 MISC, (Minor), Spray Additive Tank, Revision 2. (Permanent)

The revision changes one of the criteria for securing containment spray. The revision changes when the spray additive tank low level alarm is received.

Summary of Safety Evaluation: The 12% spray additive tank level low level alarm is not received in simulations since the spray pumps must be secured due to low RWST level. A 12% spray additive tank level change is sufficient for NaOH addition to adjust the containment sump pH to >7 as recommended by Westinghouse Nuclear Safety Advisory Letter NSAL 93-016 to prevent stress corrosion cracking of emergency core cooling components. Previous containment spray termination criteria did not consider containment sump pH. EOPSTPT V.8 describes the basis for the 12% spray additive tank level change using results of Calculation N-94-062. The minimum pH of 7.5 required by FSAR 6.4 is provided with 600 gallons (12%) from the spray additive tank. A volume of 600 gallons is equivalent to a 12% level change. Tank level book (TLB, 19 states a 12% level change provides a 600 gallon volume change within the normal operating range. (SER 94-066)

12. 1&2ICP-02.001; 1&2ICP-02.001RD-1; 1&2ICP-02.001WH-1; 1&2ICP-02.001BL-1; 1&2ICP-02.001YL-1; Unit 1 and Unit 2, (Major), Reactor Protection and Emergency Safety Features Analog Quarterly Surveillance Test, Revision 0. (New Procedures)

Summary of Safety Evaluation: The procedures are standard upgrade procedures based on existing Instrumentation and Control procedures, superseded by these procedures.

The reactor protection system (RPS) and emergency safety features (ESF) analog test frequencies are changed in accordance with revised TS 15.4.1-1. The procedures verify that equipment is returned to service upon completion of the test.

Testing methodology of the RPS and ESF systems is not changed by these tests. FSAR 7.2.2 and 7.5.2 is not changed because the systems are not degraded by the tests. (SER 94-031)

13. 1ICP-02.005A-1; 1ICP-02.005B-1 and 1ICP-02.019-1, Unit 1, (Minor), ESF System Logic Trains A & B Shutdown Surveillance Test and ESF System Logic A & B Train Monthly Surveillance Tests, Revision 3. (Permanent)

The change removes the coil resistance checks for the ESF timing relays. Other checks for continuity of the ESF circuits and other relays are not removed. The coil resistance check verifies that the timing relay is in the circuit, not that it actually functions.

Summary of Safety Evaluation: The new timing circuit relays are Agastat ETR relays which have an electronic timing circuit. This prevents coil resistance from being measured until the relay has timed out. The relays still fail in the same modes as the old relays by failing to actuate or to actuate in the prescribed time allowed.

The Agastat ETR relays are 3 times less likely to fail as the Agastat pneumatic relays. The ETR relays replace outdated Agastat Series 2400 relays. The electronic timing circuit on the ETRs are more accurate in infrequent use applications because pneumatic relays can become plugged up; thus causing the relay actuation time to vary. The six ETR relays that start the service water (SW) pumps are checked each month during EDG testing. Tests show that not checking the relay resistance is not a factor in relay operability.

The timing circuits are functionally tested on an annual basis. The coil resistance check for the timing relays only reveals they are in the circuit. Therefore, removal of this requirement does not degrade the margin of safety as discussed in Technical Specifications. (SER 94-028)

14. 1ICP-02.005A-1; 1ICP-02.005B-1; 1ICP-02.019-1; 2ICP-02.005A-1; 2ICP-02.005B-1; and 2ICP-02.019-1, Unit 1 and Unit 2, (Major/Minor), ESF System Logic Trains A & B Shutdown Surveillance Test and ESF System Logic A & B Train Monthly Surveillance Tests, Revision 4. (Permanent)

Summary of Safety Evaluation: The changes remove the coil resistance checks for the ESF timing relays. Other continuity checks of the ESF circuits and other relays are not removed. The coil resistance check verifies that the timing relay is in the circuit, not that it actually functions. The new timing circuit relays are Agastat ETR relays that have an electronic timing circuit to prevent the coil resistance from being measured until the relay has timed out. The relay still fails in the same modes as the old relays by failing to actuate or failing to actuate in the prescribed time allowed.

The Agastat ETR relays are 3 times less likely to fail as the Agastat pneumatic relays. The ETR relays replace outdated Agastat Series 2400 relays. Only 4 failures are reported to NPRDS on the dc Agastat ETR relays. (SER 94-028-01)

15. ICP-02.012; and 1&2ICP-02.012-1, Unit 1 and Unit 2, (Major/Minor), Independent Overspeed Protection System Analog and Logic Circuits Monthly Surveillance Test, Revision 0. (New Procedures)

Summary of Safety Evaluation: The procedures are standard upgrade procedures based on existing Instrumentation and Control procedures, superseded by these procedures.

While this specific surveillance test is not described in the FSAR, it is a Technical Specification-required activity per Table 15.4.1-1, Item 22. The procedures may be performed at any plant condition. Turbine-generator overspeed is analyzed in FSAR 14.1.12. This activity opens both units' sliders, making both units' independent overspeed protection systems (IOPS) inoperable while

this test is performed. TS 15.3.4.F requires only one turbine overspeed protection system that trips the turbine stop valves or shuts the turbine governor valves to be operable. This test does not disable the mechanical or auxiliary governor overspeed trips.

The IOPS input to the crossover steam dump system is made inoperable when the sliders are open. However, the crossover steam dump system is not inoperable because redundant parallel EHC system Train A and B contacts enable the crossover steam dump system to perform its function. The crossover steam dump system is operable, but the EHC contacts originate from a single overspeed protection controller card making the crossover steam dump susceptible to a single failure mode for ≈1.5 hours during performance of this activity. The crossover steam dump system is not designed to be single failure proof; therefore, it does not need two diverse redundant inputs. An administrative limit is placed on the time the IOPS system can be placed out-of-service. Either or both units may be out-of-service for up to 72 hours. Steps are incorporated to ensure these administrative limits are maintained. The test methodology does not vary from that of previous performances of this surveillance activity. (SER 94-056)

16. 1&2ICP-02.018; and 1&2ICP-02.018-1, Unit 1 and Unit 2, (Major/Minor), Reactor Trip Breaker and Turbine Trip Circuit Trains A and B Shutdown Surveillance Test, Revision 0. (New Procedures)

Summary of Safety Evaluation: The procedures are standard upgrade procedures based on existing Instrumentation and Control procedures, which are superseded by these procedures.

While this specific surveillance test is not described in the FSAR, it is a Technical Specification-required activity per Table 15.4.1-1, Item 22 and Table 15.4.1-2, Items 26 and 27. Test methodology is partially described in FSAR Section 7.2.2. This procedure is performed with the reactor in hot, cold or refueling shutdown. This test disables the operating unit IOPS (a redundant overspeed protection trip to the mechanical overspeed trip) output to the turbine to prevent a possible turbine trip. However, this test does not disable the mechanical or auxiliary governor overspeed trips. As discussed in FSAR Page 10.2-16, test circuitry is provided to prevent tripping of the turbine while testing. The test methodology does not vary from that of previous performances of this surveillance activity. (SER 94-019)

17. 2ICP-02.020; 2ICP-02.020-1; 2ICP-02.020-2; 2ICP-02.020RD-1; 2ICP-02.020WH-1; 2ICP-02.020BL-1; 2ICP-02.020YL-1, Unit 2, (Major/Minor), Post-Refueling Pre-Startup RPS and ESF Analog Surveillance Test, Revision 0. (New Procedures)

Summary of Safety Evaluation: The procedures are standard upgrade procedures based on existing Instrumentation and Control procedures, superseded by these procedures.

Procedures are made unit and channel-specific. One procedure tests annunciators after reaching normal temperature and pressure. Another procedure checks that equipment is returned to normal. The activity directed by these procedures is required by Technical Specifications and is described in the FSAR. The procedures are performed while the unit is shut down. Testing methodology is not changed from previous procedures. Steps are included to verify equipment is returned to service. Engineering setpoint changes for ΔTsp1 and 2 and loop current corrections for setpoints for high steam flow and high-high steam flow bistables are incorporated. (SER 94-055)

18. ICP 3.9, (Minor), RTD Response Time Check, Revision 5. (Permanent)

A test method using available equipment and monitoring a plant transient monitors all or part of the loop RTDs during a plant cooldown transient. Individual RTDs respond to the temperature change by following the temperature ramp of the surrounding fluid. The difference in response time is displayed as an offset between the readings as the ramp continues towards a steady-state rate of change. This

offset remains constant and corresponds directly to the difference in time constant. Several factors influence the results, including loop transport time and whether the RTD is in the hot or cold loop. Differences in response time are calculated and allow direct comparisons to be made between the RTDs.

Summary of Safety Evaluation: Monitoring of the RTDs is accomplished by one of the following methods: Required plant conditions when testing is to occur (HSD); no channels are placed in trip since the test point is used as the monitored point; monitoring occurs during a controlled cooldown from ~547 to 540°F (the cooldown transient should be 50-75°F per hour); or, stabilize temperatures after the transient to confirm a level of signal magnitudes.

Cooldown is within the limiting cooldown rate of 100°F per hour. Additionally, the cooldown is for a small temperature span of ~7°F and is near the normal operating temperature. Thus, no stresses greater than a normal plant transient are placed on the RCS. The procedure directs that the required shutdown margin be maintained.

Simulations of the desired plant transient are performed. ICP 3.9 provides specific direction to the operator to prevent a cooldown in excess of Technical Specification requirements. The procedure also directs the operator to the displays which may be used to monitor the cooldown. Direction is provided to the operator to slow or suspend the cooldown if the rate is seen to be excessive and ensures that sufficient shutdown reactivity margin is provided prior to the cooldown.

No equipment is placed out of service or adversely effected due to the performance of this test. Equipment involved is operated within the normal range. Testing is conducted on the narrow range RTDs only, with no anticipated effects on operator indication or protective functions. The testing equipment that interfaces with the RTD test points has very high input impedances (>100 Kohms) and is attached at the amplifier test points. This is a typical configuration for equipment monitoring and testing. (SER 94-044)

19. ICP-13.001; ICP-13.001-1 through 5; 1&2ICP-13.001; and 1&2ICP-13.001-1 through 5, Unit 1 and Unit 2, (Major/Minor), Radiation Monitoring System Electronic Calibrations, Revision 0. (New Procedures)

Summary of Safety Evaluation: The procedures are standard upgrade procedures based on existing Instrumentation and Control procedures, which are superseded by these procedures.

While these specific radiation monitoring system surveillance tests are not described in the FSAR, they are a Technical Specification-required activity. They provide instructions to satisfy portions of Technical Specification surveillance refueling period calibration requirements for Table 15.7.4-1, Items 1-4 and Table 15.7.4-2, Items 1-6. Steps are included to provide a list of prerequisite component and system conditions necessary for performance. The procedures are unit-specific for ease of preparation of procedure packages. Steps checking rotameter sample flow for 1&2RE-211 and 1&2RE-212 are removed. Health Physics uses FIT-3288 for sample flow determinations. The revision includes steps for DSS permission and signature blocks for work completed on equipment listed in the procedure. Acceptance criteria statements are included.

These procedures may be performed at any plant condition. Although this activity may make equipment important to safety inoperable, redundant channels and manual sampling meet TS requirements. The test methodology does not vary from that of previous performances of this surveillance activity. (SER 94-033)

20. IWP 92-089*B1 and B2, Unit 1, (Minor), Removal of HHSI Pumps Automatic Switchover Safeguards Circuitry, Revision 0. (New Procedure)

IWPs 92-089*B1 and B2, remove the high head safety injection (HHSI) pump automatic switchgear safeguards circuitry per MR 92-089*B (Reference: SER 90-128). During installation, each train of the Unit 1 safeguards control power is removed from service to isolate the components located in the safeguards racks for removal. Only one train of Unit 1 safeguards control power is isolated at a time. Unit 2 safeguards control power is not affected by the IWPs. Each valve is electrically isolated while changes are made to the valve control circuitry.

Summary of Safety Evaluation: The continuity of wires installed to complete the daisy chain of safeguards control power is verified to ensure that no piece of equipment is left without power. ORT 3 and ORT 6 test procedures, along with the safeguards logic test, verifies that safeguards control power is not broken.

One train of Unit 1 safeguards control power is electrically isolated during the removal of the safeguards logic circuitry. Circuits that use the safeguards automatic sequencing of loads onto the buses still have manual operation available. Only one train of Unit 1 safeguards control power is out of service at a time. The work is performed during cold shutdown so the SI timing application for safeguards is not necessary because SI signals are normally blocked during cold shutdown. Service water availability is the limiting case during installation. The normal SW pump start on Unit 1 undervoltage is disabled during the Unit 1 train work. This option is disabled because the Unit 1 applicable train SI time delay relay is out of service during this evolution. Therefore, 2P32D-F SW pumps run to preclude effects on normal SW operation because of a loss of normal power to the Unit 1 bus whose SW pump time delay relays are being worked on. The affected SW pumps still start on a Unit 2 undervoltage signal or a Unit 2 SI signal. Therefore, SW system operability for Unit 2 is not impaired. The other shared safeguards load, P38B auxiliary feedwater pump, also starts on a Unit 2 SI signal.

When either train of safeguards control power is out of service, the containment penetration which cannot be isolated by the other train of safeguards alone is noted on CL-1E, Attachment A. The ability to isolate containment before the RCS time-to-boil is maintained during installation. The margin of safety for service water operability per Technical Specification 15.3.3.D is not degraded. (SER 94-009)

21. OI-2A and B, Unit 2, (Minor), 2HX-1A&B Steam Generator Leak Check, Revision 9. (Temporary)

The temporary change uses P38B auxiliary feedwater pump (AFP) to perform the leak check of the Unit 2 "A" steam generator (SG) instead of P38A. This involves opening the manual crossconnect valves AF-30 and AF-43 between the motor-driven AFPs discharge piping. It also includes placing AF-4021 (P38B discharge to 1HX-1B) in manual and shut to ensure the operability of P38A to Unit 1.

Summary of Safety Evaluation: P38B AFP is used for the Unit 2 "A" SG test because P38A is considered protected equipment for Unit 1 during the LCO timeframe in which the new EDG tie-in is taking place. The precautions regarding protected equipment are also discussed in SER 93-025-23.

The AF system is not an initiator for any accident previously evaluated in the FSAR but rather, mitigates the consequences of an accident, responds to a unit trip, and operates during normal startup and cooldown. The AF lineup does not affect the operating unit in any way that could increase the probability of occurrence of an accident previously evaluated in the FSAR. P38A AFP is operable and unaffected by this evolution. P38B AFP is already out of service during this time. No other equipment important to safety is affected in a way that would increase the probability of its failure or malfunction. Thus the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR is not increased.

During this evolution P38B AFP is inoperable to Unit 1 and under an LCO per TS 15.3.4.C.2 (U2R20 only). Shutting AF-4021 (P38B AFP discharge to Unit 1 "B" SG) is in the scope of the LCO for P38B AFP. P38A AFP remains operable to Unit 1 throughout the evolution. During the timeframe when the manual crossconnects are open and P38B AFP used to supply flow to the Unit 2 "A" SG through the P38A AFP discharge piping, an automatic auxiliary feedwater initiation on Unit 1 causes the Unit 2 "A" SG supply valve from the P38A discharge, AF-4022, (which is open for the test) to shut and the Unit 1 "A" SG supply valve from the P38A discharge piping, AF-4023, which is shut, to open. P38A AFP starts and supplies design flow to the Unit 1 "A" SG. This ensures P38A AFP remains operable to Unit 1 per the licensing basis.

Appropriate steps are taken to ensure P38A is operable to Unit 1 when the P38A&B discharge piping is crossconnected. It is able to perform its design function to assist in mitigating the consequences of an accident previously evaluated in the FSAR. Appropriate electrical loading controls ensure G01 EDG or the 2X13 transformer are not overloaded by running P38B AFP when the buses are tied. Thus G01 EDG is unaffected by the evolution and is available to mitigate the consequences of an accident previously evaluated in the FSAR. P38B AFP is out of service and an AFP LCO is entered. There is a relaxation via the LCO that applies single failure criteria to the auxiliary feedwater that meets the licensing basis. However, the loading analysis allows P38B AFP to run, essentially providing additional redundancy for the auxiliary feedwater system. Therefore, the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR is not increased.

The auxiliary feedwater system is not an initiator of an accident. The electrical loading analysis ensures G01 EDG is affected. Failures of components in the auxiliary feedwater system are evaluated. Single failure criteria are relaxed via the LCO so multiple failures of components are not addressed. However, P38B AFP is available as a redundant component during the evolution. No other failure mechanisms are created that could affect other equipment important to safety. (SER 94-054)

Summary of Safety Evaluation: A step is added to OI-2A for a designated operator to place the P38B AFP control switch in pullout following an SI signal on Unit 1. An assigned operator is also required to close the manual cross connect valves to restore normal system lineup.

The P38A discharge piping is connected to the P38B discharge piping, but no flow paths to the SGs exist through the P38B discharge piping. This allows P38A AFP to supply design flow to Unit 1. P38B discharge control valve, AF-4019 is almost throttled shut to perform the 800 psig test of the SGs. A designated operator in the control room places the P38B AFP control switch in pullout following a Unit 1 SI signal. This prevents additional flow from feeding Unit 1 "A" SG. Subsequent to an AF automatic initiation to Unit 1, the normal AF lineup is restored. There is also a requirement for an assigned operator to shut the manual crossconnect valves, AF-30 and AF-43, subsequent to an AF initiation. Once the normal lineup is restored, P38B AFP is utilized to supply the Unit 1 "B" SG as the electrical loading analysis permits. (SER 94-054-01)

22. OP-4B, (Minor), Reactor Coolant Pump Operation for Degraded Voltage Considerations, Revision 25. (Temporary)

The temporary change relates to disabling the degraded voltage protection on the associated safeguards bus to ensure the safeguards bus is not inadvertently disconnected from the preferred offsite power system.

Summary of Safety Evaluation: In accordance with TS Table 15.3.5-3.a, when degraded voltage relay protection is disabled, it is necessary to declare the associated EDG inoperable for the affected bus. However, having the EDG inoperable to the affected bus is only applicable for degraded voltage conditions. Under a loss of voltage condition, the EDG is fully operable and the EDG itself, as an emergency generator, is fully operable. However, the control circuit to the normal feeder breaker to the safeguards bus is degraded. Also, prior to making the degraded voltage protection inoperable, shared safeguards equipment and unitized opposite train safeguards equipment required for plant conditions is verified to be operable.

Per TS 15.3.7.B.1.g, if an EDG is inoperable, the opposite EDG is tested daily to ensure operability and the engineered safety features associated with the opposite EDG shall be operable. If an EDG is found inoperable and the problem is quickly corrected, that EDG is tested, not the opposite EDG. In this case, since the loss of voltage protection is maintained operable and the degraded voltage protection is made inoperable and then quickly restored, it follows that the degraded voltage protection is verified operable rather than testing an EDG that is not degraded. Verification of power available to the degraded voltage relays verifies operability since the only action taken to disable them has been removal of dc power by pulling fuses. The affected operability of the normal feeder breaker control circuit which contains the degraded voltage protection logic is verified within 24 hours to ensure complete system operability. Therefore, testing of the EDGs is not deemed necessary since operability of the degraded voltage protection is subsequently verified.

As additional conservative action, while the degraded voltage protection is disabled, an assigned operator in the control room is available to disconnect the affected safeguards bus from offsite power under the conditions of a safeguards actuation on either unit. Also, prior to starting a RCP, offsite system voltage is verified to be above the low alarm setting (354 kV) to better ensure that a degraded voltage condition does not occur. (SER 94-014)

23. 4B, (Minor), Reactor Coolant Pump Operation for Degraded Voltage Considerations, Revision 26. nporary)

The change disables degraded voltage protection on the associated safeguard bus to ensure the safeguards bus is not inadvertently disconnected from the preferred offsite power system.

Summary of Safety Evaluation: Prior to starting a RCP, the associated degraded voltage protection is momentarily disabled to ensure that the associated safeguards bus is not inadvertently disconnected from the preferred offsite power source. When the degraded voltage relay protection is disabled, per TS Table 15.3.5-3.4.a, it is necessary to declare the associated EDG inoperable for the affected bus. Having the diesel inoperable is only applicable for degraded voltage conditions. Under a loss of voltage condition the diesel is fully operable and the diesel itself, as an emergency generator, is fully operable. However, the control circuit to the normal feeder breaker to the safeguards bus is degraded. Also, prior to making the degraded voltage protection inoperable, shared safeguards equipment and unitized opposite safeguards equipment required for plant conditions are verified to be operable.

The change prevents simultaneously defeating the emergency power supply to two opposite trains of required safeguards buses.

Per TS 15.3.7.B.1.f&g, if an EDG is inoperable, the opposite EDG is tested to ensure operability, and the engineered safety features associated with the opposite EDG shall be operable. There is no requirement to test the opposite EDG prior to making the associated EDG inoperable, but this is good operating practice. If an EDG is found inoperable, and the problem quickly corrected, that EDG is tested, and not the opposite EDG. Similarly, since the loss of voltage protection is maintained operable and the degraded voltage protection is made inoperable and then quickly restored, it follows that the degraded voltage protection is verified operable rather than testing an EDG that is not degraded. Verifying power available to the degraded voltage relays (1A05, 1A06, and 2A05), or verifying test switches closed (2A06) verifies operability, since the only action taken to disable degraded voltage protection is to pull dc power fuses, or open test switches. Therefore, testing the EDGs is not deemed necessary since operability of the degraded voltage protection is verified.

As an additional conservative action while degraded voltage protection is disabled, an assigned operator in the control room is available to disconnect the affected safeguards bus from offsite power under the conditions of a safeguards actuation and degraded voltage on either unit. Also, prior to starting a RCP, offsite system voltage is verified to be above the low alarm setting (354 kV) to better ensure that a degraded voltage condition is not achieved. (SER 94-061)

Summary of Safety Evaluation: The change prevents simultaneously defeating the emergency power supply to two opposite trains of required safeguards buses below 200°F on the affected unit. Only one F R pump is operating when degraded voltage fuses are removed for 2A05 and degraded voltage relays are defeated for 2A06. (SER 94-061-01)

24. OP-4D, Parts 1-4, (Major), Draining the RCS, Revision 43. (Permanent)

The revision allows for draining the RCS whether or not in reduced inventory and with or without fuel. The change also addresses the removal of blank flanges at RC-576 and 577 and the shutting of RC-570A&B, 580A&B and 575A.

Summary of Safety Evaluation: During draindown operations of the RCS the RV water level is monitored via LT-447/447A. The instruments sense the column of water in the RV via one of the incore flux mapping tubes. The instruments also compensate for gas pressure in the RCS by sensing the gas pressure in the pressurizer. If there is water level in the pressurizer surge line and the RCS gas vent valves are shut then there is a possibility that the pressurizer gas pressure could be different than the gas pressure the RV is subjected to. This causes LT-447/447A to be inaccurate. By removing the blank flange between RC-576 and 577 it is assured that the pressurizer and RV head are both vented to the same conditions (containment atmosphere). RMP 96 removes the RV head and contains necessary steps and administrative controls to ensure reliable operation of LT-447/447A. The pressurizer and RV head is at the same gas pressure when the surge line is empty, regardless of whether the valves are open or the blank flange is removed. The only time there could be a pressure difference is when the surge line contains water. (SER 94-008)

25. OP-4D, Parts 1-4, (Major), Draining the RCS, Revision 43. (Permanent)

OP-4D allows for draining the RCS whether or not in reduced inventory, and with or without fuel.

Summary of Safety Evaluation: The WE response to NRC Inspection Report 90-022 contained an NRC commitment to maintain the flow path for LT-447/447A via red tags to maintain their operability. This safety evaluation slightly alters that commitment. During the course of U1R21, the piping system to the RV head must be removed to allow the RV head to be removed. To allow for shutting RC-570A&B and 580A&B, the pressurizer is vented to containment by removing the blank flange at RC-576 and RC-577, thus ensuring the level transmitters remain vented to the same conditions. Foreign material exclusion is prevented by use of screening the opening. This ensures the transmitters are operable due to reliance on less piping. RMP-96, OP-4D, RP-1B, and OP-4A contain procedural steps for accomplishing this. Use of a screen on the opening prevents the opening from being closed off airtight. (SER 94-008-01)

26. OP-4D, Part 3, (Major), Draining the Cavity and RCS with Fuel in the Vessel, Revision 1. (Permanent)

The revision allows the refueling cavity to be used for redundant decay heat removal with the upper internals installed per DCS 3.1.26, Qualification of the Refueling Cavity for Decay Heat Removal. The change also adds a step to have both trains of RHR available prior to reducing level to less than the top of the RCCA drive shafts per DCS 3.1.26.

Summary of Safety Evaluation: The changes do not affect any accident previously analyzed. OP-4D, Part 3 and the TS interpretation (DCS 3.1.26) can be used during shutdown conditions. This does not conflict with TS or FSAR requirements.

The change does not affect the manner in which equipment is operated. AOP-9C is replaced by SEP-1 and is the preferred procedure. Redundant decay heat removal is still maintained. Only the qualification criteria for redundancy is clarified. Criteria is calculated and discussed in DCS 3.1.26 and Calculation N-94-131. There is sufficient flow area between the RV and the cavity with the upper internals installed to allow cavity cooling of the core should RHR be lost.

The margin of safety in TS 15.3.1.A.3 is not reduced. The TS and its Basis allow taking one train of RHR out of service while the refueling cavity is flooded. TS do not specify to what level the cavity needs to be filled nor whether the upper internals need to be removed. The Basis for allowing removal of one train of RHR is that the flooded cavity acting as a fuel storage pool provides conservative conditions should operability problems develop in the other train of RHR. The qualification criteria for redundancy is clarified. There is sufficient flow area between the RV and the cavity with the upper internals installed to allow cavity cooling of the core should RHR be lost. The 8-hour minimum time-to-boil is based upon being longer than the shortest expected time-to-boil when the internals are removed. This is with the RCS at 140°F (the TS and RP-1C maximum refueling temperature), the cavity flooded to internals lift level (where it would be when the internals are initially lifted), and 5 days after shutdown; time-to-boil is seven hours.

Use of a SI pump to refill the cavity places the core under a forced convection regime. The SI pump is also a safety-related piece of equipment and capable of performing its function should RHR be lost. The internals lifting rig is typically removed quickly after the internals are set in order to commence latching rods. In the unlikely event that the lifting rig is attached, sufficient time exists prior to boiling (RV is still full of water and a reduced flow area between the RV and the cavity exists) to either lift the internals or remove the rig. (SER 94-060)

27. ORT-3B, Unit 2, (Major), Safety Injection Actuation With Loss of Engineered Safeguards AC Unit 2, Revision 29. (Permanent)

The change addresses the G04 EDG tie-in work performed. The procedure is also used as part of the G04 EDG operability determination.

Summary of Safety Evaluation: The major revision for the G01 EDG test is performing the degraded voltage and undervoltage test in conjunction with the load shedding and restoration test. However, G01 EDG is not loaded and the breakers are placed in the test position as previously done (Reference: Calculation N-91-016). The remainder of the G01 EDG test is fundamentally the same. G02 EDG is now a Unit 1 only EDG and as such is not tested during this procedure.

The changes do not increase the probability of occurrence of an accident or malfunction of equipment important to safety previously evaluated in the FSAR. The test is conducted during cold shutdown in accordance with Technical Specification requirements. The availability of offsite power is not affected by these procedures. G04 EDG is specific to Unit 2 and affects only the shared auxiliary feedwater and service water for Unit 1. The shared loads remain available to Unit 1.

The changes to this test do not create any new accident initiators. During the test, both trains of RHR are operable. The test is performed by train and RHR cooling is not interrupted. Equipment is used within its design basis and no new malfunctions of equipment are created by the changes.

ORT-3 is performed to demonstrate ECCS and EDG operability as described in the FSAR. The new test goes beyond the requirements of Technical Specifications. The expanded testing of G04 EDG is an enhancement to the prior test in order to demonstrate new EDG operability. The more rigorous test demonstrates G04 EDG capabilities and performance under design conditions. (SER 94-059)

28. ORTs-71, 72, and 73, (Major), Electrical Penetration Leak Test. (Permanent)

ORTs-75, 76, 77, 78, 79, 80, 81, 82, 83,and 84, (Major), Mechanical Penetration Leak Test. (Permanent)

The revisions clarify the conditions necessary for performing 10 CFR 50 Appendix J, Type B leak tests.

Summary of Safety Evaluation: Testing these penetrations at power is similar in risk to the Appendix J Type B tests performed by existing procedures to leak test the containment hatches and purge supply

and exhaust valves as required by TS 15.4.4.II.C. Upon completion of wire tracing for each system/train, followup testing is performed on circuitry traced. Testing maintains system operability. Terminal blocks and components are visually inspected before and after wire tracing to ensure wires did not become disconnected during wire tracing. (SER 94-020)

29. PBNP 8.4.1, (Minor), Use of Ethanolamine as pH Control Agent in Secondary Side Water. (Permanent)

The change involves substituting ethanolamine (ETA) for morpholine as the pH control agent used in the secondary system.

Summary of Safety Evaluation: The use of ETA is consistent with the intent of EPRI PWR Secondary Water Chemistry Guidelines and Westinghouse Guidelines for Secondary Water Chemistry. The potential of excessive corrosion or other adverse effects is not identified and is not expected to occur. The previously analyzed consequences of potential excessive corrosion (e.g., tube rupture, feed line break, and turbine missiles) are not increased nor has the probability of such postulated events increased. No mechanism is identified for an accident not previously analyzed. The safety factors used in design evaluations of the components including the pressure boundary stress analysis completed in accordance with the ASME Boiler and Pressure Vessel Code remain valid. (SER 94-035)

30. PBTP 021-1, (Minor), As-Built Wire Tracing of G01 EDG Panels C34, C34A, C64 and C64A, Revision 0. (New Procedure)

Hand-over-hand wire tracing is performed in C34, C34A, C64 and C64A, G01 EDG local control cabinets. The tracing is performed during the G01 EDG annual outage. Individual wires are traced by removing wire bundle ties and noting each terminated end for as-built conditions. At the conclusion of tracing, wires are rebundled to their as-built condition or better.

Summary of Safety Evaluation: Wiring is traced from components to terminal boards and from terminal boards to cabling. Termination information is recorded. Non-conductive tools are utilized to remove wire bundles and panel covers to minimize the possibility of short circuits. Precautions are included in the procedure, such as pre-job briefings and the presence of an as-built engineer provide necessary support.

Complete functional testing or verification of continuity for affected circuitry is performed. Concurrent checks are used for testing performed in C02 main control board. In addition, voltage checks in C02 are taken at terminal boards containing only G01 EDG circuitry. Thus, no other system is affected. A list of components verifies that component functionality or circuit integrity is maintained.

Wire tracing is limited to local control circuitry for G01 so no other systems are affected. Circuitry is functionally tested, checked for continuity, or when this is impractical, visually inspected to assure circuit integrity. Precautions ensure that no other system is affected by G01 testing done in C02. Temporary changes made to maintenance procedures performed during the diesel outage serve only to verify circuit integrity and do not affect diesel maintenance. (SER 94-003)

31. PBTP 022-1, (Minor), As-Built Wire Trace of G02 EDG Panels C35, C35A, C65, C65A, Revision 0. (New Procedure)

Hand-over-hand wire tracing is performed in C35, C35A, C65 and C65A, G02 EDG local control cabinets. The tracing is performed during the G02 EDG annual outage. Individual wires are traced by removing wire bundle ties and noting each terminated end for as-built conditions. At the conclusion of tracing, wires are rebundled to their as-found condition, or better.

Circuitry in cabinets wire traced are checked for continuity upon completion of the trace to ensure wiring is not altered. Existing procedures functionally test most of the circuitry traced. Additions are made to the procedures to test the remaining circuits by voltage checks, continuity checks and

observations of relay states. In some cases functional tests are not practical and checkoffs for visual inspections are added to the wire trace procedure.

Summary of Safety Evaluation: Wires are traced from components to terminal boards and from terminal boards to cabling. Termination information is recorded. Wire bundles and panel covers are worked on with non-conductive tools to minimize the possibility of short circuits. A pre-job briefing is conducted and an as-built engineer is present to provide necessary support.

Complete functional testing or verification of continuity for affected circuitry is performed. The changes do not affect EDG maintenance or circuit integrity. Concurrent checks are used for testing completed in the C02 main control board. In addition, voltage checks in C02 are taken at terminal boards containing only G02 EDG circuitry, thus no other system is affected. A list of components verifies that functionality or circuit integrity is maintained. (SER 94-005)

32. PBTP 025, -1, -2, -3, -4, (Major/Minor), As-Built Wire Tracing and Followup Testing in Section 1C03 of the Main Control Board, Revision 0. (New Procedures)

The procedures provide hand-over-hand wire tracing and followup testing for Unit 1 safety-related components in Section 1C03 of the main control board. The components involve the Unit 1 RHR; Unit 1 main steam system; CC system; Unit 1 steam-driven auxiliary feedwater system; and Unit 1 feedwater isolation.

Summary of Safety Evaluation: The tracing of RHR components is performed when the plant is not relying on the components to remain operable. RH-700, 701, and 702 valve control switches are traced and inspected for operability prior to the plant going on RHR for cooldown. 1P10A and 1P10B control switches are traced when their respective train is out of service for maintenance.

1P11A control switch, 1AF-4000 control switch and 1AF-4006 are Train B powered and are traced only after their Train A redundant piece of equipment is tested. Therefore, the opposite train of the respective systems always remains operable.

Systems remain operable during wire tracing and are not affected unless a wire becomes disconnected. LCO entry is not required during routine wire tracing as the activity alone does not affect the operability of a system or component. A disconnected wire is reported to the DSS and responsible engineer for analysis of its function and impact on system operability. An LCO is entered if necessary and the wire is promptly reconnected.

Additional safety precautions are taken to prevent other possible system impacts. Ceramic wire cutters are used wherever possible to prevent electrical shorts, and wire tie straps are collected and discarded to prevent interference with relay contacts. A visual inspection/check tightening prior to work commencing is performed for safety-related components and terminal blocks on risers in 1C03.

Non-safety-related systems having wiring or components in 1C03 include Unit 1 lube oil; Unit 1 condensate and feedwater; circulating water; Unit 1 EH control; and Unit 1 steam dump. The non-safety-related systems are not directly affected as circuitry for these systems are traced.

Upon completion of wire tracing for each system/train, followup testing is performed on circuitry traced. Testing maintains system operability. Terminal blocks and components are visually inspected before and after wire tracing to ensure wires have not become disconnected during wire tracing. (SER 94-020)

33. PBTP 026, -1, -2, -3, -4, (Minor), As-Built Wire Tracing and Followup Testing in Section 1C04 of the Main Control Board, Revision 0. (New Procedures)

The procedures discuss as-built work on 1C04 of the main control board with Unit 1 in cold shutdown. The scope entails visual inspections, tightening of connections, hand-over-hand wire tracing and testing

of safety-related circuitry in 1C04. The systems with circuitry to be traced are the Unit 1 RCS; Unit 1 CVCS; Unit 1 reactor protection system; Unit 1 nuclear instrumentation system; and Unit 1 containment purge supply and exhaust systems.

Summary of Safety Evaluation: The containment purge supply and exhaust and containment isolation systems remain operable during the work. One train of these systems is to be traced and tested before the other train can be traced. However, should a wire become disconnected it is reported to the DSS and the responsible engineer. The wires function and impact on the system is then analyzed. An LCO is entered if necessary and the wire promptly reconnected.

Boration paths that are relied on throughout the outage are not affected. No wire tracing or followup testing is to be performed on equipment while the plant is relying on its operability.

Additional safety precautions are taken to prevent other possible system impacts. Ceramic wire cutters are used wherever possible to prevent electrical shorts. Wire tie straps are collected and discarded to prevent interference with relay contacts.

Other systems having wiring or components in 1C04 include Unit 1 vital instrument bus 120 Vac system, Unit 1 rod drive control system, Unit 1 control rod drive and cooling H&V, containment cleanup system H&V, and reactor cavity cooling H&V. The systems are not directly affected as circuitry for the systems is not traced. Furthermore, the majority of the components are physically separated from the components being traced.

Upon completion of wire tracing for each train, followup testing is performed on circuitry traced. Testing maintains system operability. Terminal blocks and components are visually inspected before and after wire tracing to ensure no wires have become disconnected during wire tracing. (SER 94-021)

34. PBTP-029, -1, -2, -3, -4, (Minor), Wire Tracing and Functional Testing of Miscellaneous Circuits in Main Control Board Section C01, Revision 0. (New Procedures)

The procedures discuss hand-over-hand wire tracing and followup testing for Unit 1 safety-related equipment in C01 main control board. The components involved are those with wiring related to Unit 1: Safeguards; auxiliary feedwater; reactor protection; containment ventilation; and safety injection. Wire tracing and followup testing is performed during U1R21.

Summary of Safety Evaluation: Required systems with redundant equipment are traced one train at a time. Thus, Train B equipment cannot be traced until Train A equipment is traced and tested. No wire tracing or testing is performed on a piece of equipment during a period in which it is relied on for operability. Therefore, systems remain operable during wire tracing. The only way the activity could affect the operability of equipment is if a wire becomes disconnected. LCO entry is not required during routine wire tracing as the activity alone does not affect the operability of a system or component. However, should a wire become disconnected, LCO entry might be necessary. The disconnected wire is reported to the DSS and the responsible engineer for analysis of its function and impact on system operability. Previous as-built work shows that wires which become disconnected are identified by the electricians performing the wire trace.

Additional safety precautions are taken to prevent other possible system impact. Ceramic wire cutters are used wherever possible to prevent electrical shorts. Wire tie straps are collected and discarded to prevent interference with relay contacts. A visual inspection/check tightening prior to work commencing is performed for safety-related components traced and the terminal block on Risers 21, 22, 23, 24, and 27 in C01.

Other systems having wiring or components in C01 include Unit 2 safeguards, Unit 2 instrument air, Unit 2 service air, service water, motor-driven auxiliary feedwater pumps, fuel oil system, Unit 2 main steam, and the rest of Unit 1 safeguards. The systems are not directly affected as circuitry for these systems is not traced.

Upon completion of wire tracing for each system/train, followup testing is performed on circuitry traced. This is accomplished through functional and electrical tests. Testing maintains system operability. (SER 94-022)

35. PBTP-034, (Minor), Leakage Test of Check Valve 2SI-867B, Revision 0. (Permanent)

Prior to increasing the spring force on AOV 2SI-839D, a 0.4 gpm Unit 2 RCS leak existed to the PRT. The leakage path was through first-off check valve 2SI-867B, through AOV 2SI-839D, and through relief valve 2SI-887 to the PRT. This procedure determines the actual leakage through the check valve. The test creates a flow path for the leakage to the "B" SI accumulator by opening AOVs 2SI-841B.

Summary of Safety Evaluation. The test contains a caution so if gross leakage is observed (e.g., >10% level change in 1 minute; 62 gpm) the flow path is immediately secured. The flow path is secured by shutting 2SI-839C&D. The AOVs are designed for 2485 psid and are expected to shut. As a contingency, the padlock is removed from the breaker for 2SI-841B and an operator is stationed by the breaker during the test in case power needs to be restored to the MOV so it can be shut to isolate the flow path to the accumulator.

If backleakage through the check valve is significant, a maximum conservative flow rate of 128 gpm to the SI accumulator is established during the test. The flow rate is based on a simplified conservative calculation using the Darcy fluid flow formula, assumes that the 2501 line class piping upstream of AOV 2SI-839D remains intact (e.g., 40' of 3/4" Schedule 160 piping) and that a 2000 psid differential pressure exists across this piping. If gross leakage is evident (>62 gpm) the flow path is immediately secured by shutting either AOV 2SI-839D and AOV 2SI-839C, which are fail shut valves, or as a contingency, 2SI-841B. In the unlikely event that the flow path cannot be isolated due to failure of all three of these valves to shut, or if the 3/4" 1501 line class piping ruptures, the result is an in-containment LOCA of <128 gpm. This leakage is within charging system capability and within the LOCA analysis. The initial test conditions require that all three charging pumps are operable.

The test procedure could only affect the SI system if both AOVs fail to shut upon termination of the flow path to the accumulator. In this case, an operator shuts the "B" SI accumulator outlet valve 2SI-841B to secure the leakage path.

The test procedure establishes leakage flow through the 3/4" piping between AOVs 2SI-839C&D, which is Westinghouse line class 1501 piping. This piping was designed for 1745 psig and 300° F. A walkdown and engineering evaluation (Calculation N-94-105) found the piping acceptable for full RCS pressure and temperature once several pipe supports are removed as initial conditions of this test. The removal of these piping supports does not affect the seismic integrity of the piping.

The high temperature leakage flow into the accumulator is cooled by the cold water in the accumulator. The relatively small volume of hot liquid which is allowed into the accumulator (e.g., ≈15% level increase, 93 gallons) does not significantly affect the bulk accumulator water temperature. This hot water rises in the tank and mixes so there is no boron dilution at the bottom of the accumulator. This small amount of water from the RCS does not create a boron dilution concern in the accumulator.

No accident of a different type is created by the test procedure. An outside containment LOCA is not a concern since the 3/4" test line is isolated in containment by valve 2SI-879A and outside containment by the manual containment isolation valves in this line. (SER 94-048)

36. REI 6.7, (Minor), Setting Flux Map Detector Limits, Revision 2. (Permanent)

The change revises steps to adjust the upper core limit of each of the flux map thimbles, (e.g., the

verselector settings) based on a new method. The new method calculates the limit based on previous flux map results, thus producing better flux map results.

Summary of Safety Evaluation: The previous method used the upper core reflector as the reference point for determining where the upper detector limit should be set. This method provides an estimate of where the limit should be set and is used for determining limits for the first flux map of a cycle. The new method uses previous flux map data and determines the detector limit to within 0.5". It aligns the upper limit of each thimble so the flux map output matches the grid alignment in the INCORE program. This is accomplished by taking the raw detector output of 310 points per trace and determining where the flux depression occurs for the third grid (Point 195 of 310). The upper limit is calculated by taking the current limit and adjusting for the offset. Aligning the output improves the calculation of hot channel factors and delta flux. The calibration of the power range detectors is thereby also improved. This method is not functionally different than the alternate method as the verselector setting is changed in either case. The procedure has a remote chance of incorrectly setting the verselector setting limits. The new method does not increase the likelihood of this error. In addition, REI 6.0, "Normal Flux Mapping Using the Incore Movable Detector System," cautions the test engineer to verify detector limits during flux mapping. It also requires the test engineer to verify that the detector is responding correctly. The INCORE program aligns the flux traces up to 7" if the detector limits are incorrect. Also, the output of the INCORE program and FMSUM alerts the test engineer to problems that may have occurred during the flux map. (SER 94-036)

37. 1RMP 9056; 1RMP 9056-1; 1RMP 9056-2 and 1RMP 9056-3, (Major/Minor), Calibration and Testing of Safety Related Protection Relays, Revision 0. (New Procedures)

The procedures are upgrades from RMPs 65A, 65B and 65C.

Summary of Safety Evaluation: Calibration and testing of the safety-related protection relays is performed while Unit 1 is in a cold or refueling shutdown. Requisite system and component conditions ensure that decay heat removal is maintained for Unit 1 and ensures design basis conditions are preserved for Unit 2 with respect to common equipment operability.

Calibration and testing of the undervoltage relays that initiate a reactor trip, (1-273/A01, 1-274/A01, 1-273/A02 and 1-274/A02) is not a concern because the reactor is in a cold or refueling shutdown condition. Similarly, calibration and testing of the underfrequency relays (1-811/A01, 1-812/A01, 1-811/A02, 1-812/A02) is not a concern because the RCPs are not in service.

Calibration and testing of the undervoltage relays (1-271/A01, 1-272/A01, 1-271/A02, 1-272/A02), that cause trip of the RCPs and an anticipatory start of auxiliary feed on low voltage is not a concern because the RCPs are not in service and auxiliary feedwater is not needed for the shutdown unit.

Calibration and testing of degraded voltage relays (1-273/A05, 1-274/A05, 1-275/A05, 1-273/A06, 1-274/A06 and 1-275/A06) is not a concern because the relay output is placed in the trip condition during calibration. Coincidence for degraded voltage protection of 1A05 and 1A06 is 1/2 during calibration and testing.

Calibration and testing of the undervoltage relays (1-271/B03, 1-272/B03, 1-273/B03,1-271/B04, 1-272/B04 & 1-273/B04) is not a concern because the relay outputs are placed in the trip condition during calibration. Coincidence for loss of voltage protection of 1B03 and 1B04 is 1/2 during calibration and testing.

While calibrating the 1A05 loss of voltage relays, the procedure requires the in-service decay heat removal loads to be powered by Train B. This ensures continuity of decay heat removal in the event of personnel error while calibrating and testing Train A 4 kV loss of voltage relays.

The procedure states that P32F SW pump should be operable prior to calibration and testing to ensure that at least 3 SW pumps are available in the event of a personnel error while calibrating and testing Train A 4 kV loss of voltage relays.

The procedure requires P38B electric-driven and P29B turbine-driven auxiliary feedwater pumps to be operable prior to calibration and testing Train A 4 kV loss of voltage relays to ensure adequate feedwater is available to the Unit 2 steam generators if RCS temperature is greater than 350°F.

The procedure requires P35B diesel-driven fire pump be operable prior to calibration and testing Train A 4kV loss of voltage relays to ensure adequate fire protection. While calibrating the 1A06 loss of voltage relays, the procedure requires the in-service decay heat removal loads be powered by Train A. This ensures continuity of decay heat removal in the event of personnel error while calibrating and testing Train B 4 kV loss of voltage relays.

The procedure requires that P32D or P32E SW pump be operable prior to calibration and testing to ensure that at least 3 SW pumps are available in the event of a personnel error while calibrating and testing Train A 4 kV loss of voltage relays. (SER 94-026)

38. 2RMP 9056; 2RMP 9056-1; 2RMP 9056-2 and 2RMP 9056-3, Unit 2, (Major/Minor), Calibration and Testing of Safety Related Protection Relays, Revision 0. (New Procedures)

The procedures are upgrades from RMPs 56A, 56B and 56C.

Summary of Safety Evaluation: While calibrating the 2A05 loss of voltage relays, the procedure requires that the in-service decay heat removal loads be powered by Train B. This ensures continuity of decay heat removal in the event of personnel error while calibrating and testing Train A 4 kV loss of voltage relays.

The procedure requires that P32A or P32B SW pumps be operable prior to calibration and testing to ensure that at least 3 SW pumps are available in the event of a personnel error while calibrating and testing Train A 4 kV loss of voltage relays. While calibrating the 2A06 loss of voltage relays, the procedure requires that in-service decay heat removal loads be powered by Train A. This ensures continuity of decay heat removal in the event of personnel error while calibrating and testing Train B 4 kV loss of voltage relays.

The procedure states that P32C SW pump should be operable prior to calibration and testing to ensure at least 3 SW pumps are available in the event of a personnel error while calibrating and testing Train B 4 kV loss of voltage relays.

The procedure requires P38A electric-driven and P29A turbine-driven auxiliary feedwater pumps be operable prior to calibration and testing Train B 4 kV loss of voltage relays to ensure adequate feedwater is available to the Unit 1 steam generators if RCS temperature is greater than 350°F. (SER 94-026-01)

39. 2RMP 9071-2, Unit 2, (Minor), 2A06 4160/480 V Degraded and Loss of Voltage Relay Monthly Surveillance, Revision 1. (Permanent)

The 4160 V bus 2A06 design allows the protective relaying for a loss of voltage to be set in a 2/3 configuration in order to trip the normal supply breaker and start the G04 EDG. TS Table 15.3.5-3 defines the undervoltage scheme for the 4160 V buses as 2-channels per bus in which only one channel is required to trip (1/2 logic). The protective relaying scheme is consistent with TS requirements.

Summary of Safety Evaluation: The new 2A06 bus is tied in and placed in service during U2R20. The new bus is designed with a 2/3 logic scheme for the loss of voltage protection. The old 2A06 had a 1/2 loss of voltage protection scheme. During this work one of the relays on the new 2A06 bus is placed in trip in order to make the 2/3 logic into a 1/2.

TS Table 15.4.1-1 requires these relays be tested monthly. In order to meet this requirement the undervoltage relays on the new 2A06 are temporarily returned to the 2/3 scheme, and the relays are tripped one at a time. This does not compromise the loss of voltage protection for the bus because the 2/3 scheme provides adequate protection and maintains the minimum degree of redundancy. Once testing is complete the scheme is returned to 1/2.

The circuit remains in a 1/2 scheme except for the short period (<30 minutes) of time for the monthly testing. During which time undervoltage protection is still provided to the bus. Failure of one relay during this period does not prevent the UV scheme from operating.

The circuit is not declared inoperable during this test because the protection scheme is not degraded. The TS intent of the 2/3 logic is met since the minimum degree of redundancy is maintained. Failure of one relay does not prevent actuation of the loss of voltage scheme. (SER 94-062)

40. SEP-1.1, Unit 1 and Unit 2, (Major), Alternate Core Cooling, Revision 0. (New Procedure)

SEP-1, "Degraded RHR System Capability" contains methods of alternate core cooling. Information from SEP-1 is included in SEP-1.1 with specific instructions provided to achieve proper equipment configuration for desired core cooling methods. Specific steps for reflux cooling and core cooling by filling the cavity to refueling height with internals in place are included in the procedure.

Summary of Safety Evaluation: Reflux cooling is accepted as a means of alternate core cooling as provided by EPRI TR-102972. SEP-1.1 specifies requirements of reflux cooling to address core cooling requirements for 10 CFR 50. Appendix R concerns when this may be the only core cooling method available.

If the cavity is flooded to the rod latch level or greater, the cavity may be used for decay heat removal. When the internals are installed, additional inventory is added by filling to the refueling height. This increases the time-to-boil since the internals prevent a complete heating of the cavity before boiling takes place. As the cavity is filled the core is cooled by forced convection and later, natural circulation is established between the cavity and the upper plenum through the openings in the internals.

Equipment is operated in the same manner as in other alternate core cooling methods with the exception of throttling flow with SI pump discharge valves SI-866A&B to fill the cavity to the refueling height when the internals are not removed. A slower flow rate of 300 gpm is desired to prolong the time for forced convection during the filling period. These valves have remote throttling capabilities but are not designed as throttle valves. The most likely result is that after throttling, seat leakage may increase. This is not a great concern since the seat leakage of these valves does not need to be maintained within specified limits as do containment isolation valves or closed system boundary valves. Throttling of these valves is also accomplished in ECA-1.1, "Loss of Containment Sump Recirculation" to prolong RWST inventory. (SER 94-049)

41. SLP 2 and SLP 10, (Major), Items Lifted by Containment Polar Crane Unit 2 and Load Weight Listings, Revision 6. (Permanent)

The revisions incorporate requirements for use of RV head shielding during refueling outage and maintenance activities. The shielding reduces personnel radiation exposure levels. The RV head shielding system is designed such that installation and removal is a routine process.

Summary of Safety Evaluation: The lead shielding blankets qualify as a heavy load per NUREG-0612; hence their movement must be carefully controlled. PBNP 3.4.5 defines the controls for the lifting of heavy loads.

MR 90-164 implements the design for the shielding and support structure and specifies the shielding storage requirements in containment during plant operation. RMP 96 controls the sequence in which the shielding is installed and removed during a refueling outage and maintenance activities such that any

lift of the RV head is not made when the shielding is installed. This procedural control is necessary so the capacity of the polar crane is not exceeded during RV head lifts.

The consequences of an accident associated with movement of the lead shielding is not explicitly discussed in the FSAR. The changes do not directly or indirectly increase the consequences of an accident and comply with PBNP 3.4.5 and NUREG-0612 requirements for heavy loads. Therefore, there is no potential for increased radiological consequences.

The integrity of the RCS pressure boundary is not affected. The capability to shut down the reactor and maintain it in a safe shutdown condition is not affected.

No fission product boundaries (e.g., fuel cladding, containment and reactor) are degraded by the procedure changes. Movement of lead shielding along an approved safe load path is similar to other previously approved equipment movements and does not increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR. (SER 94-043)

42. SMPs 1145, 1146, 1147, and 1148, (Minor), Replacement of 1&2A05/A06 Degraded Grid Voltage Relays, Revision 0. (New Procedures)

The procedures install degraded grid voltage relays for buses 1&2A05 and 1&2A06.

Summary of Safety Evaluation: During installation, fuses on the secondary side of the bus potential transformers are removed. This causes isolation of relays from the respective bus. Since work is performed on equipment already isolated, the procedures do not increase the probability of an accident.

Under normal conditions, the relays provide three functions: 1) Automatic startup of the EDGs; 2) loss-of-voltage protection; and 3) degraded grid voltage protection. Since the EDGs are out of service during installation, the lack of automatic startup is inconsequential; therefore, the procedures do not increase the consequences of an accident previously evaluated in the FSAR. Loss-of-voltage protection for the components indirectly supplied by A05/A06 are provided by the loss-of-voltage relays at B03/B04. Degraded grid voltage protection is provided by the opposite train common 4160 V safeguards bus. The relays at these buses are in service and monitoring voltage from a source that is shared with the bus undergoing the relay installation. (The buses share a common low voltage station auxiliary transformer.) If the relays trip because of degraded grid voltage, the operators are instructed to open the feeder breaker to the bus undergoing relay installations. This trips the loss-of-voltage relays at the respective 480 V bus (B03/B04) and strips the necessary components. Since loss-of-voltage and degraded grid voltage protection are provided, the procedure does not increase the probability or the consequences of a malfunction of equipment important to safety. (SER 94-002)

43. SMP 1149, (Major), Isolating and Replacing SW-16, Revision 0. (New Procedure)

SMP 1149 removes and replaces SW-16, north Zurn strainer, SW-2911-BS inlet valve, with a rebuilt valve. To allow sufficient time to repair the valve, SW-16 is replaced with the rebuilt valve.

Summary of Safety Evaluation: Initially, P32D and P32F service water pumps are removed from service. An LCO is not entered for taking two service water (SW) pumps out of service because four SW pumps are still operational (two on each train). A 24-hour LCO is entered prior to isolating the north half of the east header by tagging shut SW-2891 (rebuilt header isolation valve) from the south, SW-63 (north header east isolation) and by tagging out P32E during the valve removal. This constitutes having less than four SW pumps operable per TS 15.3.3.D.2.a. Shutting SW-63 requires an alternate supply of seal water be established for circulating water pumps 2P30A&B. The supply is routed from the threaded union before 2CW-61A, traveling screen strainer blowdown, using 1-1/2" hose and connection to threaded unions in the 2" SW piping between SW-29 and SW-30.

The control room is contacted to ensure the SW system pressure is adequate to maintain system operability based on leakage out of the system. Calculation N-93-113 indicates a maximum inlet lake water temperature of 64°F when isolating the north half of the east header with 1000 gpm of leakage past the isolation valves. If the isolated section of header depressurizes, leakage past the isolation valves will be minimal and the valve can be removed from the header. AOP-9A states the pressure should be >50 psig to prevent SW pump cavitation, although pump cavitation is not a concern when flow is supplied through the south header. The valve is replaced with a rebuilt valve. To protect the three south SW pumps while returning the north header, SW-63 is opened, SW-16 leak checked, and SW pumps returned to service before opening SW-2891. The new SW-16 valve is then leak tested and the LCOs are exited.

The SW system remains operable with regard to seismic concerns throughout the valve replacement since shims are placed under each of the six discharge check valves to reduce loads on the header. The operable SW pumps are not affected because the isolated section of header is tested leak tight. Controlled leakage in the pumphouse does not affect the other SW pumps or diesel fire pump because adequate drainage can be established in the pumphouse. This was determined during past SW valve replacements. The only other equipment important to safety which could be affected are the circulating water pumps and traveling water screens. Shutting SW-63 requires routing water from a screen wash strainer blowdown to the Unit 2 circulating pump seals to keep the cutlass bearing from overheating during this evolution.

The SW pumps are also safe shutdown equipment required to respond to a "worst case" fire for 10 CFR 50 Appendix R concerns. Due to separation concerns resulting from the location of the particular SW pumps removed from service, twice per shift fire watches are posted in the pumphouse and G01 emergency diesel generator room as a prudent action.

If an SI actuation signal is received while three north pumps are isolated, then the affected unit turbine building feeder is isolated because the logic requires nonessential loads to be isolated when less than 4 SW pumps are operating after an SI signal. The resulting loss of coolant to the lube oil cooler could damage turbine bearings. To prevent this damage, contingencies were included in the procedure to supply cooling to the lube oil cooler of the affected unit using fire water if there is an SI actuation signal. This is considered an emergency condition which allows the use of the fire water system for this purpose.

If service water must be routed to the north header from the east header in a timely manner, a contingency exists to install blind flanges on the header flanges so the north service water pumps can be started to route flow around the north Zurn strainer bypass. (SER 94-004)

44. SMPs 1150, 1151, 1152, and 1153, Unit 1 and Unit 2, (Minor), Train A & B Degraded Voltage Time Delay Setpoint Change, Revision 0. (New Procedures)

The procedures and setpoint document reduce the time delay setting on the following Agastat time delay relays to the minimum possible setting: 1&2TDRA/A05 and A06; 1&2TDRB/A05 and A06; and, 1&2TRDC/A05 and A06.

Summary of Safety Evaluation: Time delay relays are reduced to ≈0.2 seconds and the total time delay associated with operations is reduced from 50 seconds to ≈10.2 seconds based on manufacturer data.

The time delay reduction associated with operation of the degraded grid voltage relays does not cause an increase in the probability of any previously evaluated accident or malfunction of equipment important to safety. It may result in the separation of safety-related buses from an unacceptable offsite source in a more rapid manner. While the actions of the degraded grid voltage relays are not specifically described in the FSAR, the action of sensing an unacceptable offsite source and subsequent transfer of safeguards loads to the EDGs is a safety-related function. The intended design of the degraded grid voltage relay scheme is to prevent damage to equipment important to safety due to inadequate supply voltage from the offsite source. The design also prevents unwanted separations from

the preferred offsite source due to transient conditions such as starting of the RCPs.

During a period where the time delay associated with the operation of the degraded grid voltage relays is less than ≈35 seconds there is a potential that starting of the RCP results in depression of 4160 V bus voltage for a period long enough to result in operation of the degraded grid voltage relaying scheme and thus transfer of the associated 4160 V safeguards bus to the EDG. Since this is an unwanted action, operators are instructed not to attempt to start the RCP motors during such periods unless the action of the relays is effectively bypassed. Given proper controls on the starting of the RCPs, it is not anticipated that other plant and system transients result in separation of the safeguards bus from the preferred offsite power source.

The reduction of the time delay associated with operation of the degraded grid voltage relays results in the same action on the safeguards buses that results from a total loss of offsite power. Since previously evaluated accidents and malfunctions of equipment important to safety assume a loss of all offsite power, the consequences do not increase. In addition, this action decreases the probability of a malfunction of equipment important to safety, thus ensuring the equipment is available to mitigate the consequences of an accident.

The activity does not create the possibility of an accident or malfunction of equipment of a different type than previously analyzed in the FSAR. The result is that the safety-related 4160 V buses disconnect from an inadequate offsite source more rapidly and are reconnected to the EDGs. Since this takes place upon a total loss of voltage from the offsite grid, it does not change the FSAR Chapter 14 accident analysis. It is not anticipated that additional plant transients or system disturbances result in unwanted operation of the degraded grid voltage relays.

The action does not affect the margin of safety as defined in the Basis of Technical Specifications. The basis for the present 50-second time delay included in Technical Specification Table 15.3.5-1 is stated in the safety evaluation supporting License Amendment Nos. 74 and 79. The Basis is maintained by the use of administrative controls. (SER 90-059-02)

45. SMP 1155, (Minor), Implementation of the 1X04 Tap Change, Revision 0. (New Procedure)

SMP-1155 changes the tap setting on the primary of 1X04 transformer from tap setting 4 (2.5% boost) to tap setting 5 (5% boost). This implements a setpoint document change previously approved by SER 90-049-03.

Summary of Safety Evaluation: Changing the tap reduces the likelihood of actuating the degraded grid relays on the A05 and A06 buses during plant transients. In order to perform the tap change the 1X04 transformer is deenergized. Technical Specifications allow removing the 1X04 transformer from service while the associated unit is shut down. Power is maintained to the 1A03 and 1A04 buses during this time by closing the 1A03 to 2A03 bus-tie and the 1A04 to 2A04 bus-tie. Also 1A01 and 1A02 are deenergized so that the Unit 2 4160 V fast bus transfer is operable. Since 1A01 and 1A02 are deenergized, the 1B01 and 1B02 buses are supplied from 1B03 and 1B04 respectively. The system is designed so an undervoltage on 1B03(04) trips the tie breakers to 1B01(02). This prevents loading the 1B01 and 1B02 loads on the EDGs. If the tie breakers fail to trip, undervoltage on 1B01(02) trips its load except for the shroud fans. The shroud fan control switches are tagged in pullout to prevent loading the shroud fans on the EDG if the tie breaker fails to trip on undervoltage.

When 1X04 transformer is deenergized, Unit 1 shutdown loads are supplied from 2X04. This transformer is analyzed to supply the maximum load that could be placed on it if a Unit 2 fast bus transfer occurs during this work. The cooling fans to 2X04 are verified operational in order to maintain the FA rating of 37.3 MVA. The loading of 2X04 is not an issue since a fast bus transfer on Unit 2 actuates the degraded grid relays and places the safeguards loads on the EDGs. The degraded grid relays on Unit 2 actuates because the tap change is not complete on Unit 2. Unit 1 and Kewaunee are expected offline during this work, so a Unit 2 trip causes the switchyard voltage to dip more than normal.

After the tap change is complete, a transformer turn ratio (TTR) test verifies acceptability of the new tap setting. To do this, the primary and secondary connections are broken. While Technical Specifications do not limit the length of time 1X04 can be out of service, it is recognized that 2X04 is relied upon as the common provider of offsite power to both units' safeguards buses. Because of this, a contingency plan minimizes the time it takes to restore 1X04, in case something happens to 2X04. 1X04 is able to be restored within four hours at all times during this work. This approach is consistent with that used in RMP-48, that removes 1X04 from service for normal maintenance. Once the TTR test is complete and the connections are restored, insulation resistance tests are performed on windings to verify no grounds are created.

During the time that G05 combustion turbine is islanded, the 13.8 kV fast bus transfer is disabled by placing the control switch for breaker H52-31 in pullout. This is no different than taking 1X03 out of service, since Unit 1 is shut down. If a lockout on 2X03 occurs, offsite power can be restored immediately with minimal breaker manipulation. Also, G05 is running which makes it more readily available as a source of offsite power.

For the duration of this work, the emergency source of power to the safeguards buses is maintained operable. Also, the reliability of the offsite power supply to Unit 2 is not affected. The procedure provides a reliable source of offsite power to the Unit 1 safeguards buses during this evolution. (SER 90-059-05)

46. SMP 1157, (Minor), Implementation of the 2X04 Tap Change, Revision 0. (New Procedure)

SMP-1157 changes the tap setting on the primary of 2X04 transformers from tap setting 4(2.5% boost) to tap setting 5 (5% boost). This implements a setpoint document change previously approved by SER 90-059-03.

Summary of Safety Evaluation: Changing the tap reduces the likelihood of actuating the degraded grid relays on the A05 and A06 buses during plant transients. In order to perform the tap change the 2X04 transformer is deenergized. Technical Specifications allow removing the 2X04 transformer from service while the associated unit is shut down. Power is maintained to the 2A03 and 2A04 buses during this time by closing the 1A03 to 2A03 bus-tie and the 1A04 to 2A04 bus-tie. Also 2A01 and 2A02 are deenergized so that the Unit 2 4160 V fast bus transfer is operable. Since 2A01 and 2A02 are deenergized, the 2B01 and 2B02 buses are supplied from 2B03 and 2B04 respectively. The system is designed so an undervoltage on 2B03(04) trips the tie breakers to 2B01(02). This prevents loading the 2B01 and 2B02 loads on the EDGs. If the tie breakers fail to trip, undervoltage on 2B01(02) trips its load except for the shroud fans. The shroud fan control switches are tagged in pullout to prevent loading the shroud fans on the EDG if the tie breaker fails to trip on undervoltage.

When 2X04 transformer is deenergized, Unit 2 shutdown loads are supplied from 1X04. This transformer is analyzed to supply the maximum load that could be placed on it if a Unit 1 fast bus transfer occurs during this work. The cooling fans to 1X04 are verified operational in order to maintain the VA rating of 37.3 MVA.

After the tap change is complete, a transformer turn ratio (TTR) test verifies acceptability of the new tap setting. To do this, the primary and secondary connections are broken. While Technical Specifications do not limit the length of time 2X04 can be out of service, it is recognized that 1X04 is relied upon as the common provider of offsite power to both units' safeguards buses. Because of this, a contingency plan minimizes the time it takes to restore 2X04, in case something happens to 1X04. 2X04 is able to be restored within four hours at all times during this work. This approach is consistent with that used in RMP-47, that removes 2X04 from service for normal maintenance. Once the TTR test is complete and the connections are restored, insulation resistance tests are performed on windings to verify no grounds are created.

During the time that G05 combustion turbine is islanded, the 13.8 kV fast bus transfer is disabled by placing the control switch for breaker H52-21 in pullout. This is no different than taking 2X03 out of

service, since Unit 2 is shut down. If a lockout on 1X03 occurs, offsite power can be restored immediately with minimal breaker manipulation. Also, G05 is running which makes it more readily available as a source of offsite power.

For the duration of this work, the emergency source of power to the safeguards buses is maintained operable. Also, the reliability of the offsite power supply to Unit 1 is not affected. The procedure provides a reliable source of offsite power to the Unit 2 safeguards buses during this evolution. (SER 94-048)

47. SMP 1159, (Minor), Isolating and Replacing SW-9, Revision 0. (New Procedure)

SMP 1159 removes and replaces the spoolpiece in the SW-9 position (south Zurn Strainer, SW-2912-BS, inlet valve) with a rebuilt valve. This safety evaluation addresses removal of the spoolpiece and installation of the repaired valve in the SW-9 position.

Summary of Safety Evaluation: A 24-hour LCO is entered because SW-2891 is inoperable while it is tagged shut. Inoperability of this valve is defined as not having the ability to be cycled locally or manually. TS 15.3.3.D.1.c states, "All necessary valves, interlock and piping required for the functioning of the service water system during accident conditions are also operable." This does not apply with this valve shut if all 6 SW pumps are operable. Calculation N-93-047 shows that in the most limiting condition (Unit 2 LOCA and G02 EDG failing to start), adequate flow is supplied to the Unit 2 fan coolers for post-accident conditions via 3 SW pumps. In the event that less than six SW pumps are operable, a 24-hour LCO is entered. This is based on the potential of not being able to provide the necessary flow rate to the accident fan coolers with 2 operable SW pumps. This is comparable to the existing TS-required LCO when less than 4 SW pumps are operable, (e.g., 2 per train, resulting in the inability to provide adequate flow to the accident fan coolers.) The 24-hour LCO can be exited by returning required SW pumps to service, or by removing the isolation tag from SW-2891 and having the ability to open both valves from the control room or with the handwheel. Although not an anticipated condition, if either SW-2890 or SW-2891 is shut while operable and there are less than 6 SW pumps operable, a dedicated operator is assigned to open the valve either locally or manually in the event of an SI signal. This ensures adequate flow during post-accident conditions. Cycling either valve for testing does not require entering the 24-hour LCO provided it remains operable and is returned to the open position, or has a dedicated operator assigned for opening in the event of an accident. Another 24-hour LCO is entered for less than four SW pumps operable per TS 15.3.3.D.2.a when the third of three south SW pumps are tagged out of service to isolate the header for the SW-9 replacement.

The SW system remains operable with regard to seismic concerns throughout the valve replacement. Shims are placed under each of the six discharge check valves to reduce loads on the header. The work is performed via an LCO that relaxes the single failure criteria for the SW system. Therefore, an additional failure of the SW system and its potential effect on equipment important to safety is not considered. The operable SW pumps are not affected because the isolated section of header is adequately leaktight. Furthermore, controlled leakage in the pumphouse does not affect the other SW pumps or the diesel fire pump because adequate drainage can be established as determined during past SW valve replacements.

The SW system is required to mitigate the radiological consequences of an accident. The SW system design was evaluated because three SW pumps are removed from service when the south half of the east header is isolated. The condition results in P32D-F SW pumps remaining in service. P32D and P32E pumps are powered from Train B and P32F is powered from Train A. Although Technical Specifications allow 3 SW pumps to be taken out-of-service via an LCO, the conservative interpretation is that one train should remain operable. This results in P32D and P32E (powered from Train B) being the operable train of SW pumps and P32F (powered from Train A) being the train degraded via the LCO. Our design basis accident loads were evaluated with 2 SW pumps available and proved to be adequate (Reference: Calculation N-90-006, Revision 1). The FSAR and Technical Specification Basis state 3 SW pumps are required. There are 3 SW pumps operable during this work.

The adequacy of two pump operation is evaluated for design basis accident loads via Calculation N-93-035 because the ring header is not intact as a section of the header is isolated. The calculation was similar to N-90-006, Revision 1, with the exception that single failure criteria is relaxed because the work is performed via an LCO. The calculation concluded that as long as Lake Michigan water temperature remain below 74°F, two pumps are capable of meeting design basis requirements. The SW system model is used to determine the consequences of system leakage.

The SW pumps are classified as safe shutdown equipment required to respond to a "worst case" fire for 10 CFR 50, Appendix R concerns. Due to separation concerns resulting from the location of the SW pumps removed from service, twice per shift fire watches are posted in the listed areas. This is consistent with Standing Order PBNP 4.12.7.

If an SI actuation signal is received while the 3 south SW pumps are isolated, then the affected unit turbine building feeder is isolated because the logic requires nonessential loads to be isolated when less than 4 SW pumps are operating after an SI signal. The resulting loss of coolant to the lube oil cooler could damage turbine bearings. To prevent this, contingencies supply cooling to the lube oil cooler of the affected unit using fire water if there is an actuation signal. This is considered an emergency condition which allows use of the fire water system.

If SW is needed to be routed to the south header from the east header, a contingency installs blind flanges on the header flanges so the south SW pumps can be started and flow routed around the south Zurn strainer bypass. (SER 93-050-01)

48. SMP 1160, (Minor), Isolating and Replacing SW-21, Revision 0. (New Procedure)

SMP 1160 removes and replaces SW-21, north Zurn strainer, SW-2911-BS, outlet valve, with a rebuilt valve.

Summary of Safety Evaluation: An alternate supply of seal water is initially established for 2P30A&B circulating water pumps. The supply is routed from the threaded union before 2CW-61A traveling screen strainer blowdown using 1-1/2" hose and connection made to threaded unions in the 2" service water piping between SW-29 and SW-30. SW-21 is then isolated by red tagging shut SW-63 (north header east isolation), SW-22 (north Zurn stainer bypass) and SW-16 (north Zurn strainer inlet). Red tagging shut SW-63 requires entering a 48-hour LCO per TS 15.3.3.D.2.c because the valve is out of service while tagged shut. The isolated portion of the SW header is drained using SW-20 (north Zurn strainer drain) and SW-19 (north Zurn strainer auto drain bypass). If the isolated section of header does not depressurize as indicated on PI-2981 (north zurn strainer outlet pressure indicator), then P32D-F SW pumps are tagged out and SW-2891 (south to north crossconnect valve) is tagged shut. A 24-hour LCO is entered because less than 4 SW pumps are operable per TS 15.3.3.D.2.a and because SW-2891 is tagged shut as described in SER 93-077.

The SW system remains operable, with regard to seismic concerns, throughout the valve replacement. Shims are placed under each of the six discharge check valves to reduce loads on the header. The work is performed via an LCO that relaxes the single failure criteria for the SW system. Therefore, an additional failure of the SW system and its potential effect on equipment important to safety is not considered. The operable SW pumps are not affected because the isolated section of header is adequately leaktight during performance of SMP 1143. Furthermore, controlled leakage in the pumphouse does not affect the other service water pumps or diesel fire pump because adequate drainage can be established in the pumphouse as determined during past service water valve removal. The only other equipment which could be affected are the circulating water pumps and traveling water screens. Shutting SW-63 requires routing water from a screen wash strainer blowdown to the Unit 2 circulating pump seals to keep the cutlass bearing from overheating during the evolution.

The SW system is required to mitigate the radiological consequences of an accident. The SW system design is evaluated because isolating the north half of the east header removes 3 SW pumps from service. This condition results in P32A-C SW pumps remaining in service. P32A&B SW pumps are

powered from Train A, and P32C is powered from Train B. Although Technical Specifications allow 3 SW pumps to be taken out of service under an LCO, the conservative interpretation is that one train should remain operable. This results in P32A&B (powered from Train A) being the operable train of SW pumps and F32C Train B being the train degraded via the LCO. Two SW pumps are sufficient for our design basis accident loads per Calculation N-90-006. Calculation N-93-113 evaluates the adequacy of two pump operation, under the interim SW header configuration, for design basis accident loads. The results show that as long as Lake Michigan water temperature remains below 67°F, two pumps are capable of meeting design basis requirements during this replacement if there was no significant leakage. If a leakage of 1000 gpm flowing past SW-2891 is assumed, the maximum permissible lake temperature is 64°F without operator action. Lake temperature is monitored throughout the evolution and nonessential loads are isolated if the temperature exceeds 64°F.

The SW pumps are classified as safe shutdown equipment required to respond to a "worst case" fire for 10 CFR 50, Appendix R concerns. Due to separation concerns resulting from the location of the SW pumps removed from service, twice per shift fire watches are posted in the pumphouse and G01 EDG room. (SER 94-029)

49. STPT 14.11, (Major), Secondary Systems: Auxiliary Feedwater, Revision 10. (Permanent)

A review of EPRI methodology for alert and alarm temperature setpoints for 1&2P29 and P38A&B auxiliary feedwater pumps (AFPs) indicate that the present alert range of 140°F-185°F and alarm setpoint of >185°F should be lowered to 120°F and >160°F.

Summary of Safety Evaluation: The revision lowers the alarm setpoint for the AFP bearings. The pump configuration, bearing configuration, or the bearing type is not changed. There is no change in the type or amount of bearing lubrication used.

The lower bearing temperature alarm setpoint is based on a revised methodology for determining the setpoint using the bearing manufacturer's minimum viscosity recommendation. The value is then combined with empirically determined data from NMAC for the type of oil in use. The value is then adjusted for the operating characteristics of the particular application. An engineering conservatism factor allows time for securing the pump upon a high temperature alarm. The intent is to minimize the damage to the pump during a bearing failure.

A review of operational and testing data indicates the bearings normally operate at 85°F. The only credible mechanism for reaching the 160°F setpoint is a bearing failure. No adverse effects to the equipment or operating characteristics are expected to occur from lowering the alert and alarm setpoints. (SER 94-068)

50. STPT 21.1, Sheets 6 and 10, (Major), Setpoint Change for 1X04 and X02 Transformer Taps, Revisions 2 and 1. (Permanent)

Tap changes on 1X04 and X02 transformers raise the output voltage level by 2-1/2%.

Summary of Safety Evaluation: QCR 94-004 describes a situation where it is possible that the degraded voltage relays (Type 27N, solid-state) installed on the Train A and B 4160 V safety-related buses, may not reset following a design basis accident or trip of the associated unit. The post-transient bus voltage has to stabilize above the reset value of the relays for the relays to reset, if the transient causes the bus voltage to initially drop below the relays operating level. Taking conservatisms into account, the maximum theoretical value required to reset the relays is at least 4011 V. Evaluations show this reset value equates to ≈355 kV which must be present on the 345 kV grid post-transient, assuming worst case loading conditions (LOCA on associated unit).

To resolve the concern with post-transient voltage levels remaining above the relay's reset value, the fixed taps on the high side of 1X04 and X02 auxiliary transformers are changed from the existing tap, that provides a voltage rise of 2-1/2% above nominal, to a tap that provides a rise of 5% above

nominal for a net change of 2-1/2%. The tap change has the effect of lowering the voltage which must be present on the 345 kV bus post-transient, in order to reset the degraded voltage relays, by ≈8.5 kV, or from 355 kV to 346.5 kV. This also lowers the minimum 345 kV bus voltage required to ensure adequate voltage to the safety-related loads (this is the degraded voltage relay operating level) by 8.5 kV to ≈340.2 kV.

Although this equipment is designed to mitigate the effects of an accident while powered from the EDGs, it is desirable to have offsite power available for these loads. The change does increase the likelihood of offsite power being available to this equipment post-accident to mitigate consequences.

There is concern that by raising the voltage available to the 4160 and 480 V safeguards loads by 2-1/2% some of the loads may see terminal voltages slightly greater than 110% of nameplate rating. This may occur in part due to the safeguards buses (supplied by X04) being normally very lightly loaded, yet requiring adequate voltage levels under very heavy starting loads (design basis accident conditions). This factor combined with a 345 kV grid voltage at the maximum expected level of 360 kV causes the 110% rating to be exceeded.

While the potential exists that certain safety-related loads may be operated at slightly above the maximum rated voltage of 110% there are several reasons why this is acceptable and does not affect the ability of the equipment to perform its safety-related function or otherwise significantly decrease its performance or service life:

- The values are determined under minimum bus loading conditions while at maximum expected 345 kV grid voltage. Normally the bus loading is greater than assumed above (e.g., service water pumps running). Under conditions when the safety-related equipment are called upon to perform its safety function, the bus loading becomes significantly greater and causes the bus voltage to drop.

- Operating motors at voltages above 110% of rating may result in increased operating temperatures similar to operating at voltages <90% of rating. However, the effect is less than that which occurs for an undervoltage of the same magnitude. Many motors even run cooler. In addition, motors stalling upon starting or contactors opening is not a concern during an overvoltage condition as it is for an undervoltage situation (Reference IEEE 141-1976).

- The degree to which the evaluations show that motors operate at voltages above 110% of nameplate rating is minimal.

- The voltages which may be present on motor-operated valves is not considered a problem because of the short-term intermittent operation of these motors.

- Most of the safety-related loads which are subject to these voltages are not continuously operating loads. Thus, the effect of such operation is minimal. In addition, the potential conditions are based on the 345 kV grid at a bus voltage of 360 kV. Under a situation where these loads are required to operate to mitigate an accident that results in a unit trip, the 345 kV bus voltage is likely to drop several kV.

- OP-2A requires that 345 kV bus voltage be maintained between 356 and 358 kV. Review of bus voltage records for 1991-1993 indicates that bus section 1 (Unit 1 auxiliaries) exceeded 360 kV for 26 hours during the period and bus section 5 (Unit 2 auxiliaries) exceeded 360 kV for 4 hours.

  Both the system control center and the operators take action when grid voltage exceeds 358 kV. System control also gets an alarm at 360 kV. Operators reduce excitation on the generators to reduce the grid voltage. System control works with the adjacent utility's system control centers to take actions such as switching of reactor banks to adjust voltage. System control may even isolate a line to the switchyard to reduce the voltage. Operators may also

take actions to increase load, and thus drop voltage, on any of the auxiliary buses. Bus voltage information for the safety-related buses is available in the main control room. The concern regarding the potential for an overvoltage condition at certain loads under maximum 345 kV grid voltage is communicated to system control.

- OI-35, Section 11 "4160/480 V Equipment," is revised to include guidance concerning testing of loads under high system voltage conditions. This supports the possibility of performing an inservice test of equipment under high grid voltage conditions with a very lightly loaded bus, which results in voltages near or slightly above the maximum 110% rating.

  The tap changes do not adversely affect the function of equipment that could initiate an accident previously evaluated in the FSAR. The tap changes are designed to decrease the likelihood of a loss of offsite power (LOOP) due to actuation of degraded voltage relays, and the failure of post-trip voltage levels to reach the degraded voltage relays reset value. These tap changes add additional margin between the normally expected 345 kV grid voltage levels, both pre- and post-transient, and the relay's operating and reset voltage levels, thus decreasing the probability of occurrence of a LOOP. The change increases the margin of safety defined in the Basis for Technical Specification 15.3.7 regarding offsite power by increasing the likelihood of offsite power remaining available post-accident.

The availability, design and function of equipment is not adversely affected by the tap changes. No new initiators are created that could create the possibility of an accident of a different type than previously evaluated in the FSAR. There is a concern regarding the subsequent voltage differential between the two units until 2X04 and X02 transformer taps are changed. The normal method of cross-tying the two units A03 and A04 buses per the routine maintenance procedure is altered to have the voltages on the buses matched or the bus deenergized when tying across. This normally is done during an outage or if a problem with an X04 transformer exists. In this case the respective unit is shut down in accordance with Technical Specifications. To address this interim concern, temporary information tags are placed on the control switches for the A03 and A04 tie breakers to note this concern. (SER 90-059-03)

51. STPT 21.1, Sheets 74 and 75, (Major), Degraded Voltage Time Delay Relay Setpoint Change. (Permanent)

The time delay setting is increased for the following Agastat time delay relays associated with the degraded grid voltage protection scheme: 1TDRA/A05; 1TDRB/A05; 1TDRC/A05; 1TDRA/A06; 1TDRB/A06; and 1TDRC/A06.

Summary of Safety Evaluation: The relays are set to a minimum time delay of ≈0.2 seconds, for a total time delay associated with operation of the degraded grid voltage relays of ≈10.2 seconds (Reference SER 90-059-02). The minimum time delay is initiated to limit the time that a safety-related load is attempting to start with less than rated voltage. However, as stated in SER 90-059-02, when the total time associated with the degraded grid voltage protection scheme is less than ≈35 seconds, starting of the RCP motors causes the 4160 V bus voltage to dip low enough to operate the degraded grid voltage scheme, resulting in transfer of the 4160 V safeguards bus to the EDG. Therefore, to facilitate startup of Unit 1, the time delay of the Agastat relays is temporarily raised to 40 seconds, for a degraded grid voltage scheme total time delay of 50 seconds. The time delay of the Agastat relays is lowered back to less than 0.2 seconds prior to arming safeguards systems, prior to increasing RCS temperature above 200°F. Automatic safeguards systems actuation do not occur since safeguards is blocked by a procedure. Automatic safeguard functions are not necessary with these plant conditions. Subsequent to returning the Agastat relay time delay to 0.2 seconds or less, operators are instructed not to attempt to start RCP motors until the degraded grid voltage relays are temporarily bypassed, via operator aids and procedures.

Degraded grid voltage is not an initiating event for an accident previously analyzed in the FSAR, and increasing the time delay associated with operation of the degraded grid voltage relays does not increase

the probability of any previously evaluated accident. The intended design of the degraded grid voltage relay scheme is to prevent damage to equipment important to safety due to inadequate supply voltage from the offsite source. The time delay associated with the scheme is intended to prevent unwanted separations from the preferred offsite source due to transient conditions such as starting of the RCPs.

Plant design and operation is not altered by raising the degraded grid voltage scheme time delay setpoint. Therefore, the setpoint change does not create the possibility of an accident of a different type than previously evaluated in the FSAR. The setpoint change does not modify safety-related equipment or change its basic function. Therefore, there are no additional types of equipment failure than those previously evaluated in the FSAR. In addition, a malfunction of a single component of the degraded grid voltage only affects one of the two redundant safeguards trains.

The setpoint change has no effect on the margin of safety defined in the Basis of Technical Specifications. The basis for the less than 60 second time delay included in Technical Specification Table 15.3.5-1 is stated in the safety evaluation supporting License Amendment Nos. 74 and 79. (SER 90-059-06)

52. TS-1 and TS-2, (Major), G01/G02 EDG Biweekly, Revision 40. (Permanent)

Attachments A and B caution statements are included to verify the fuel oil transfer system is working properly and ensures the EDG is not run without a fuel source (e.g., sump inadvertently run dry due to a faulty level indicator or FTS-L mercoid failure). In the event that G01 or G02 EDGs are operated until shutdown due to no fuel, there is no detrimental effects to the EDGs or their fuel systems.

Summary of Safety Evaluation: The engine fuel system consists of two fully redundant supply subsystems. The primary system consists of the engine fuel oil pump and its associated filters, strainers and check valves. The secondary system consists of a continuously energized electric-driven fuel oil pump, its associated filters, strainers and check valves. The check valves coordinate the interaction of the two systems as well as control the return portion of the system.

In the event of loss of fuel suction the engine stops. The cooling and lubricating function of the fuel in the injectors cease; however, this condition is seen during all shutdowns and is therefore not a function of loss of fuel suction. During a normal shutdown sequence the electric fuel pump is stopped. In the event of loss of fuel suction the electric fuel pump continues to run until the engine stop pushbuttons are depressed. Because the pump is a positive displacement pump this tends to further fill the fuel oil system with air.

In the event that a loss of fuel suction occurs, the following actions must be taken: Restore fuel level in the sump tank; depress the fuel prime pushbutton until fuel pressure is indicated (This restores fuel in the majority of the fuel systems; however, there will be air in the "engine driven" portion of the system.); and, start the engine and idle for 5 minutes (This ensures the engine driven portion of the system is refilled with fuel and trapped air is pushed out.)

The loss of suction is not expected to have a detrimental effect on the strainers and filters. The sump tank can be clean because of the degree of filtering between the day and sump tanks. Debris may consist of corrosion particles and paint chips. No floating debris is expected to exist in the tank.

The loss of fuel suction has no detrimental effects on the longevity of the engine or fuel system. Restoration of the fuel system after the loss of suction does not involve extraordinary efforts other then to reprime the system utilizing the installed system. (SERs 94-051 and 94-052)

DESIGN CHANGES

The following modifications were installed as of the end of 1994:

1. MR 84-228*C, (Unit 2), Instrument Buses. MR 84-228*C installs static transfer capability for four safety-related instrument bus inverters including: Relays, power supply modules and associated wiring in ASIP 2C20 for static switch interlocks and annunciator circuits; alternate power supply cable connections to the red and blue instrument bus inverters; rerouting of conduits and cables from the white and yellow instrument bus inverters to their associated static transfer switches; energization of the alternate ac power source; and, startup and testing of each static transfer switch.

   Summary of Safety Evaluation: The static transfer switches transfer to the alternate ac source upon an inverter failure or a fault condition that causes instrument bus voltage to drop below a preset level. Following a transfer to the alternate source, the affected instrument buses are manually transferred back to the normal or swing inverter via a switch at each inverter or static transfer switch. The instrument bus alternate ac source is intended to be used only until the affected instrument buses are returned to the normal or swing inverter supplies.

   The static transfer switches are seismically qualified and have the same ratings as their associated inverters. New raceways and equipment are seismically installed. Existing safety train separation is maintained.

   The alternate ac source is non-safety-related. Equipment associated with the alternate source is non-QA. This is acceptable because a failure of the alternate source does not cause an inverter failure nor does it prevent the inverters from supplying their respective instrument buses. The interface between the non-safety-related alternate source and the safety-related instrument buses is at the static transfer switches, which are safety-related. The alternate source transformer is equipped with surge and lightning protection to reduce the potential for voltage transients on the alternate source. The static switches have surge protection and design features that prevent voltage transients on the alternate source from affecting static switch operation. Electrical interlocks are provided to prevent inverters from more than one instrument bus channel transferring to the alternate source at the same time. The interlock prevents overloading of the alternate source, and prevents instrument buses from two different channels of the same unit from being supplied from a single non-1E source.

   Each inverter is removed from service to make connections to the static switch. The swing inverters provide power to the instrument buses while the normal inverters are out of service. Testing of the static transfer switches is performed while the associated inverter is supplying only "dummy" loads. Following testing of each of the static transfer switches, the associated instrument buses are transferred to the alternate source to verify proper operation. This is performed during a refueling outage to minimize risk.

   The alternate ac source is sized to supply the instrument buses fed from a maximum of two inverters. Worst case loading occurs if the static switches for two inverters transfer to the alternate source (25 kVA x 2 = 50 kVA). Using single failure criteria, this could occur on loss of the dc bus supplying either the white or yellow inverters (note that 3 inverters fail, including the swing inverter, but only two are loaded). The possibility of more than two loaded inverters failing at the same time is extremely remote. Interlocks are used to prevent the alternate source from simultaneously supplying more than two loaded inverters. (SER 91-083-02)

2. MR 85-025*D, (Common), HVAC. MR 85-025*D replaces rubber steam hoses in the control room with insulated copper tubing. The new tubing is suspended from trapeze hangers in the ductwork. MR 85-025 installs new control and computer rooms humidifiers. The steam supply to the dispersion tubes is through a high temperature rubber hose. The new fiberglass insulated copper tubing is soldered with non-lead bearing solder for higher strength at elevated temperatures.

Summary of Safety Evaluation: The control room HVAC system assures control room habitability during normal and accident conditions. The system removes heat loads from the computer and control rooms and provides filtered air to the control room during control room isolation conditions.

Failure of the new copper tubing does not affect the emergency function of the HVAC system. The supply duct is pressurized with respect to the surrounding areas. Failure of the tubing does not allow radioactive contamination to enter the duct. Air flow is out of the ducting. (SER 90-121-01)

3. MR 87-121*I, (Common), 480 V Switching Devices. MR 87-121*I adds seismically supported switches to the G01 and G02 EDG rooms; Unit 1 and 2 charging pump areas; Unit 2 facade; holdup tank pump room; electrical equipment room; and, 2B32 MCC room.

Summary of Safety Evaluation: The switches meet the original 10 CFR 50 Appendix R commitment for switchgear room bypass. Additional loading to the structures was analyzed for seismic effects. The results show acceptable loading capabilities in these areas. MR 87-121*I does not add raceways or conduit to the affected switches. (SER 90-116-06)

4. MR 87-121*Q, (Common), 480 V Distribution. MR 87-121*Q adds seismically designed conduit for the routing of cables associated with the alternate shutdown system. The conduits are added to the PAB El 8', 26' and 46'; turbine building El 26' and 44'; and control building El 8' and 26'.

Summary of Safety Evaluation: MR 87-121*Q alters a description in FSAR 7.2 that states, "This signal is carried in conduit and cable trays which have been studied for resistance to seismic forces. Appropriate supports have been added to typical configurations to withstand the accelerations determined for the building and elevation through which the conductor is passing." The conduits are installed in accordance with WE Specification PB-220, "Specification for Safety Related Electrical Installation." As a specification requirement, the contractor fabricates and installs the supports in accordance with design guideline DG-E02. The guideline requires Seismic Class 1 conduit supports and ensures the design meets the requirements of FSAR 7.2.

The alternate shutdown modification ensures that a source of 480 V power is available in the event of a fire in the following fire zones: 305 (vital switchgear room), 318 (cable spreading room) and 326 (control room). The conduits are routed and externally protected to enable compliance with the overall requirements of the modification.

Procedure CP-E3.0, Section 4.2.3, requires the contractor install conduit runs so conflict with passageways or access to the operation or maintenance of electrical or other equipment is avoided. The requirement ensures the modification does not adversely impact other equipment. (SER 90-116-01)

5. MR 87-121*R, (Common), 480 V Distribution. The modification installs 3000 kVA, 13.8 kV/480 V switchgear and local switching devices necessary to provide a dedicated source of 480 V power to selected plant equipment independent of the 4 kV switchgear room.

Summary of Safety Evaluation: MR 87-121*R ensures that train separation and/or separation of normal/alternate sources is provided and maintained, and that safe shutdown operability is provided for specific plant equipment in accordance with 10 CFR 50 Appendix R requirements. The interface between the alternate (dedicated shutdown) supplies and existing Class 1E equipment is via Class 1E switching devices. Equipment and raceways associated with the alternate supplies are seismically installed. The switching devices utilize mechanical interlocks such that the normal and alternate sources cannot be tied together. It is possible to deenergize both normal and alternate 480 V supplies

to a given piece of equipment by switching it at the local switch panels. Although not required based upon criteria of Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems," control room annunciation is provided to alarm abnormal switching alignments.

The modification does not affect the present operation of existing equipment/systems when switching devices are in their normal alignment. A worst case failure of equipment associated with the dedicated shutdown system requires fire watches in one or more fire areas. <u>(SER 87-054)</u>

6. <u>MRs 88-093*D, (Unit 1) and 88-094*D, (Unit 2)</u>, Secondary Chemical Treatment System. The modifications install the mechanical portion of the hydrazine injection system.

<u>Summary of Safety Evaluation</u>: MRs 88-093*D/094*D do not change the chemical addition point into the condensate system nor the secondary system water chemistry action levels. Therefore, corrosion rates of the steam generator tubes are not negatively impacted by the change.

A malfunction of the hydrazine controller is detectable by the residual hydrazine, oxygen or pH analyzers. Abnormal levels cause secondary sample panel alarms that call for the control room secondary sample panel alarm. If a problem with hydrazine feed rate is identified, the pumps can be placed in manual operation if necessary to repair or adjust the controller. Hydrazine addition is accomplished by manual control of the pumps, thus proving the acceptability of manual pump control.

The feedwater flow signal is obtained by connecting to the existing I/I that is converter connected to steam generator "A" feedwater flow loop. This provides a signal to the hydrazine pumps in the old hydrazine addition system. Since the old hydrazine pumps are only operated in a manual mode, the removal of the old signal cable may be accomplished at any time. The I/I converter provides isolation to protect the feedwater flow signal loop. As an additional precaution during installation, "A" steam generator main feedwater control is placed in manual for a short time while the old feedwater flow signal is disconnected and the new cable is terminated. The time is minimal in which the feedwater control switch is in manual.

The fluid handling components are compatible with the chemical concentrations being used. The pressure and temperature ratings of these components meet the system design ratings. The system design and construction is in accordance with Power Piping Code B31.1.

Hydrazine spills are addressed in AOP-12A. The floor sloping and nearby turbine hall sump drain at the skid sites allow the chemicals to be contained within the plant boundaries. A service water hose connection is available within ≈20' of each skid and can be used to wash down spills. A subsoil drain manway exists just east of the Unit 1 skid location. The floor is sloped such that a chemical spill would not naturally flow toward the manway. However, if a catastrophic tank failure occurred, a portion of the initial slug of liquid could flow to the manway. In order to guard against this unlikely event, the manway opening is sealed just below the manway cover. The seal is designed such that it could be temporarily removed if access to the manway is ever required. For personnel safety, an eyewash/shower station is installed at each of the skid locations. If the eyewash/shower stations are not installed prior to initial use of the systems for chemical injection, then portable eyewash/shower bottles are placed at the skid locations. The CHES sheets for the chemicals are available at the skids.

The systems do not present an unacceptable increase in fire loading. The highest concentrations of the chemicals present at the skid locations are 35% hydrazine and 40% morpholine. In these concentrations these chemicals do not burn. The chemicals at these concentrations are not considered flammable and therefore do not need to be kept in fire-proof storage cabinets. If hydrazine spills are wiped up with rags, procedures instruct the worker to rinse the rags thoroughly with water after use to ensure the rags do not present a fire hazard as they dry. <u>(SER 89-103-02)</u>

7. MR 88-145,(Common), Control Room HVAC. MR 88-145 replaces VNCR-4840A&B, control room and computer room backdraft dampers. The dampers are located downstream of the control room supply fans W13B1 and B2.

Summary of Safety Evaluation: The installation returns the control/computer room ventilation supply system to its as-designed condition. The new dampers differ from the old in that they have an external balancing arm which allows adjustment and balancing of the system. This difference in damper design is considered an improvement to the operation/maintenance characteristics of this system.

During installation the control room emergency filtration system is operable. The system is designed to filter the control room atmosphere and makeup air during control room isolation conditions, thus, maintaining habitability of the control room. In accordance with TS 15.3.12.3, an LCO is entered during installation. In the event of a monitor alarm, the operators don respirators per standard procedures and training actions. Operator action and procedures maintain control of the control room in the event of an accident.

An operability concern exists with high room temperatures because it may affect the computer equipment and impact plant operations. The FSAR states that equipment in the control/computer rooms function properly in temperatures up to 110°F. Testing is performed prior to installation to ensure the control/computer rooms are maintained in the normal range (75°F ± 10°F). (SER 94-015)

8. MR 88-188*H, (Common), Service Water. MR 88-188*H enhances control room valve position indications for various SW safety-related MOVs. The change improves valve operability. MR 88-188*H replaces existing 2-rotor with 4-rotor limit switches for valves SW-2016; SW-2930A; SW-2930B; SW-2869; SW-2870; SW-2890; and SW-2891.

Summary of Safety Evaluation: The modification enhances the accuracy of valve status information in the control room by providing independent limit-switch rotors for two functions previously wired from a single rotor: Closed valve position indication and open torque switch bypass. Since each rotor can be set at any valve-stem position, splitting these two functions to independent rotors allows for separate limit-switch setpoints for the closed valve-position indication and the open torque switch bypass. The replacement enhances valve operability by allowing the open torque-switch to be bypassed longer and reduces the possibility of the actuator tripping out on open torque and the valve not opening.

MR 88-188*H requires the valve worked on to be electrically isolated and remotely inoperable for ≈12 hours. With the exception of SW-2816, SW-2869, and SW-2870, it is still possible to manually operate the valves as needed to maintain their function during accident conditions. Although it is not possible to operate valves SW-2816, SW-2869, and SW-2870, during the rebuild, their respective manual valves SW-502, SW-224, and SW-221 are used instead, should isolation be required. Position indication is not available in the control room after power is removed for limit switch changeout. Valve position is determined locally by examining valve stem position.

The valves are worked on one at a time and are stroke tested after installation. MOV diagnostic equipment is used to verify valve operability and proper control room indication is verified. The exact piping and electrical system isolation boundaries and valve position is based on other work being performed at the time of installation.

The new limit switch assemblies are not EQ. The additional rotors add negligible weight to the operator and therefore do not affect the seismic classification. (SER 92-066-12)

9. MR 88-188*J, (Common), Motor-Operated Valves. MR 88-188*J replaces 2-rotor limit switches with 4-rotor limit switches for the following MOVs: AF-4009, AF-4016, FO-3930 and FO-3931.

Summary of Safety Evaluation: The valve position indication wiring change provides detection of motor thermal overload relay actuation for these valves and improves valve operability. The change also enhances the accuracy of valve status information in the control room by providing independent

limit switch rotors for two functions previously wired off of a single rotor: Closed valve position indication and open torque switch bypass. Since each rotor can be set at any valve-stem position, splitting these two functions to independent rotors allows for separate limit-switch setpoints for the closed valve-position indication and the open torque switch bypass. The replacement enhances valve operability by allowing the open torque-switch to be bypassed longer and reduces the possibility of the actuator tripping out on open torque and the valve not opening.

The modification requires the valve being worked to be electrically isolated an inoperable for ≈12 hours during the work. The valves may be manually operated as necessary to maintain their function during accident conditions. Position indication is available in the control room after power is removed for limit switch changeout or thermal overload relay rewiring. Valve position is determined locally by examining valve stem position.

The new limit switch assemblies and intermediate gear cases are procured as EQ equipment for EQ valve operators. EQ wire is installed on the EQ valves. The additional rotors and gear cases add negligible weight to the operator. Therefore, the change does not affect the seismic analysis. (SER 92-066-07)

10. MR 88-188*K, (Unit 1), Motor-Operated Valves. MR 88-188*K enhances the control room valve position indications for various safety-related MOVs. The change improves valve operability. MR 88-188*K replaces existing 2-rotor with 4-rotor limit switches for 16 MOVs. Rewiring of the position indication wiring in the limit switch housings provides actuation indication of the valve motor thermal overload devices for 1OS-0001-MOV and 1OS-0002-MOV.

The limit switch replacement is performed on the following Unit 1 valves: AF-4006, CC-0719, CC-754A, CC-754B, SI-841A, SI-841B, SI-852A, SI-860A, SI-878B, SI-878C, SI-878D, SW-2907, and SW-2908. The change enhances the accuracy of valve status information in the control room by providing independent limit switch rotors for two functions previously wired off of a single rotor: closed valve position indication and open torque switch bypass. Since each rotor can be set to change at any valve stem position, splitting the two functions to independent rotors allows for separate limit switch setpoints for the closed valve position indication and the open torque switch bypass. The replacement enhances valve operability by allowing the open torque switch to be bypassed longer and reduces the possibility of the actuator tripping out on open torque and the valve not opening.

Summary of Safety Evaluation: The modifications require the valve being worked on to be electrically isolated and inoperable for ≈12 hours during the work. The valves are manually operated as necessary to maintain their function during accident conditions. Position indication is not available in the control room after power is removed for limit switch changeout. Valve position is determined locally by examining valve stem position. The exact piping and electrical system isolation boundaries and the position of the valve worked on is determined by Operations personnel based on other work being performed at the time of installation.

The new limit switch assemblies and intermediate gear cases are procured as EQ equipment for EQ valve operators. EQ wire is used for installation on EQ valves. The additional components (rotors, gear cases) add negligible weight to the operator and therefore do not affect the seismic analysis.

Once installed, the MOV enhancements decrease the consequences of an accident since control room operators have improved indication of valve position and improved valve operability. It also reduces the probability of equipment malfunction (e.g., an MOV not opening when required) because the MOVs open torque switch is bypassed longer.

No new system components are installed. The modification enhances the existing component functions and does not introduce the possibility of a new accident. Since the modification is internal to the components evaluated for malfunction in the FSAR, any malfunction associated with the modification could at worst cause the valve to be inoperable, which is already evaluated in the FSAR. (SER 92-066-10)

11. MR 88-188*L, (Unit 2), Safety Injection System. MR 88-188*L replaces 2-rotor limit switches with 4-rotor limit switches for the following MOVs in Unit 2: CC-754B, SI-841A, SI-860D, SI-878A-D, and SI-896A.

Summary of Safety Evaluation: The modification enhances the control room valve position indications for various safety-related MOVs. The change improves valve operability. The change enhances the accuracy of valve status information in the control room by providing independent limit switch rotors for two functions previously wired from a single rotor: Closed valve position and open torque switch bypass. Since each rotor can be set to change the state at any valve stem position, splitting the two functions to independent rotors allows for separate limit switch setpoints for the closed valve position indication and the open torque switch bypass. The replacements enhance valve operability by allowing the open torque switch to be bypassed longer; thus, reducing the possibility of the actuator tripping out on open torque and the valve not opening.

The modifications require the valve being worked on to be electrically isolated and inoperable for ≈12 hours during the work. However, the valves may be manually operated as necessary to maintain their function during accident conditions. Position indication is not available in the control room after power is removed for limit switch changeout. Valve position is determined locally by examining valve stem position. The exact piping and electrical system isolation boundaries and the position of the valve worked are determined by Operations personnel based on other work being performed at the time of installation.

The new limit switch assemblies and intermediate gear cases are procured as EQ equipment for EQ valve operators. EQ wire is used for installation on EQ valves. The additional rotors and gear cases add negligible weight to the operator and therefore do not affect the seismic analysis.

The MOV enhancements decrease the consequences of an accident since control room operators have improved indication of valve position and valve operability. The installation also reduces the probability of equipment malfunction (e.g., an MOV not opening when required) because the MOVs open torque switch are bypassed longer. (SER 92-066-11)

12. MRs 89-072, (Unit 1) and 89-073, (Unit 2), Feedwater System. MR 89-072 resolves an NRC commitment that enables individual leak testing/closure verification for check valves 1&2CS-466AA&BB and 1&2CS-476AA&BB. The testing is performed in accordance with ASME Section XI requirements.

Summary of Safety Evaluation: The modification installs test connections that enable individual leak testing of each of the existing check valves. A buttweld pipette fitting is welded to the main feed pipe using proper welding and heat treatment techniques. A 2" line is installed connecting the pipette fittings on both sides of each check valve. A 2" gate valve is also installed in the run of pipe between the two pipette fittings. The materials used meet design requirements and are compatible with the existing system materials. The design meets seismic requirements.

The piping system is sloped in a similar manner as the old main feedwater line. The system is heat traced as required to aid in freeze protection.

There is no change in the function of the main feedwater system or its isolation check valves. The main feedwater check valves prevent auxiliary feedwater from flowing backwards through the main feedwater lines. This does not change with MR 89-072. The test line is isolated by locking the gate valve shut while the unit is at power. The new 2" bypass valve associated with each of the second-off check valves (CS-466AA and CS-476AA) is added to the list of CIVs in the FSAR and tested as such per ISI procedures. The valves do not interfere with proper main feedwater isolation requirements.

Containment closure controls ensure proper closure during installation. The work is performed on one check valve at a time with the other intact. This ensures proper containment closure is available in case of an emergency.

A probabilistic safety assessment (PSA) of each main feedwater line, independently addressed for the probability of the main feedwater system becoming a flow diversion path such that the auxiliary feedwater system cannot perform its design function. Two possible failure paths analyzed determined this to be a very low probability factor. The data shows that the valve failures required to occur for the system to fail is not a safety significant contribution to a failure of the auxiliary feedwater system to perform its design function. There is less than a 1% contribution to a failure of the auxiliary feedwater system.

The assessment also addressed the system configuration after installation. The independent rate is determined to be 3.6.E-11/demand. This is slightly greater than the old condition but still very safe in regard to the overall system safety and reliability. The second failure assessment analyzed a common mode failure of the change. The rate is determined to be 2.0E-8/demand, the same as the common mode failure rate of the old system. This again represents a very safe system. The safety assessment concluded that the probability of system failure with the installation increases slightly because more valves are added. However, the valve additions are not a safety significant contribution to the failure of the auxiliary feedwater system to perform its design functions. (SERs 94-013, 94-013-01, and 94-013-02)

13. MR 89-078*A, (Unit 2), Crossover Steam Dump. MR 89-078*A installs thermometers on the crossover steam dump stacks.

    Summary of Safety Evaluation: MR 89-078*A installs remote reading thermometers on the steam dump stacks. The gauges are mounted to a panel on the side of the platform that surrounds the steam dump valves.

    Components are adequate for Seismic Class 2 qualification so that the crossover steam dump valves and surrounding equipment are not impacted during a seismic event. The old crossover steam dump system and the new gauges are not seismically qualified, and are non-QA.

    There are no 10 CFR 50 Appendix R concerns. The installation does not affect the operation of the steam dump system. (SER 90-033)

14. MR 90-005, (Unit 1), Main Control Boards. MR 90-005 removes the pressurizer low level channel alert circuitry. The safety injection (SI) portion of the circuitry was previously disconnected and abandoned in place. The remainder of the circuitry still provides unnecessary annunciator and status light indications. During installation, each train of Unit 1 safeguards control power is isolated so components are removed. Only one train of Unit 1 safeguards control power is isolated at a time. Unit 2 safeguards control power is not affected by the modification.

    Summary of Safety Evaluation: Removal of unnecessary alarms and abandoned SI signal wiring does not cause safety concerns. The components are not necessary for plant safety since TMI. The continuity of wires installed to complete the daisy chain of safeguards control power is verified to ensure no piece of equipment is left without power. ORT 3 and ORT 6 test procedures, as well as the safeguards logic test verify that the safeguards control power is not broken.

    One train of the Unit 1 safeguards control power is electrically isolated during the removal of components and wiring associated with the pressurizer low level channel alert circuitry. Circuits that use the safeguards automatic sequencing of loads onto the buses still have manual operation available. Only one train of Unit 1 safeguards control power is out of service at a time. The work is performed during cold shutdown so the SI timing application for safeguards is not necessary. SI signals are normally blocked during cold shutdown. Service water availability is the limiting case during installation. The normal SW pump start on Unit 1 undervoltage is disabled for the Unit 1 train worked on because the Unit 1 undervoltage sequencing uses the Unit 1 applicable train SI time delay relay which is out of service. Therefore, Unit 2 powered P32D-F SW pumps are run to preclude affects on normal SW operation due to a loss of normal power to the Unit 1 bus whose SW pump delay relays are being worked on. The affected SW pumps start on a Unit 2 undervoltage signal or a Unit 2 SI signal,

therefore SW system operability for Unit 2 is not impaired. The other shared safeguards load P38B AFP also starts on a Unit 2 SI signal. Thus the consequences of an accident or malfunction of equipment is not increased.

When either train of safeguards control power is out of service, containment penetrations which cannot be isolated by the other train of safeguards are noted on CL-1E, Attachment A. The ability to isolate containment before the RCS "time-to-boil" is maintained during the modification. The margin of safety for SW operability per TS 15.3.3.D is not degraded. (SER 94-011)

15. MR 90-014*B, (Unit 2), Safety Injection System. MR 90-014*B modifies the limit switch contacts for 10 MOVs and 5 AOVs that supply the SI spray ready status panel indications. The change is necessary since most of the indications are not considered correct (e.g., for normally open valves the light illuminates only when the valve is on its shut seat). The valves modified include: 2SI-841A&B, 2SI-878B&D, 2SI-896A, 2SI-866A&B, 2SI-870A&B, 2SI-896B, 2SI-897A&B, 2RH-624, 2RH-625 and 2RH-626.

Summary of Safety Evaluation: The location of wires that supply indication to the SI spray ready status panel are changed to correct contacts on each valve's limit switch. The changes aid Operations personnel by giving accurate indications on the SI spray ready status panel and provides better assurance of proper valve positioning for the associated systems. Valves 2SI-870A&B also have an electrical interlock with valves 2SI-871A&B rewired as part of the modification (one Train A, one Train B). The interlock, which prevents the SI-871 valves from opening until the SI-870 valves are fully shut, is supplied by an auxiliary relay that also supplies the current SI status light indication for the SI-870 valves. The interlock is hard wired into the circuit by using the valves limit switch and removes the auxiliary relay interface. This reduces the chance of interlock failure by removing one component that could possibly fail. The work is performed during the U2R20 refueling outage to negate the need for SI and containment spray systems. (SER 92-068-01)

16. MR 90-159*B, (Unit 1), Feedwater System. MR 90-159*B adds six drain/vent valves to the Unit 1 secondary piping systems. Two of the valves are on the gland steam headers, two on the No. 3 feedwater heater drain lines, and two on the No. 3 feedwater heater dump lines.

Summary of Safety Evaluation: Each drain/vent connection is 3/4" NPS, and is located as close as possible to the low point/high point of each of the referenced lines. Each connection allows the piping section to be depressurized and the energy to be safely relieved prior to maintenance efforts.

The vent/drain connections provide a method of relieving the high-energy fluid from these lines so that six AOVs are more safely maintained. This minimizes the potential for personnel burn injuries.

The connection additions do not affect the FSAR, Technical Specifications, or prior commitments to the NRC. The new connections comply with USAS B31.1-1967 (as reconciled with ANSI/ASME B31.1-1986 with addenda) requirements and other original piping system design requirements. The installations are non-seismic, non-QA, and non-safety-related. (SER 93-019-01)

17. MR 90-160*C, (Unit 2), Feedwater System. MR 90-160*C adds 11 drain/vent valves in the Unit 2 secondary system piping systems. Two of the valves are on the gland steam headers, two on the No. 3 feedwater heater drain lines, two on the No. 3 feedwater heater dump lines, two on the condenser steam dump lines, one on the main steam to heating steam line, and two on the main feedwater lines.

Summary of Safety Evaluation: Each drain/vent connection is 3/4" NPS and is located as close as possible to the low/high point of each of the referenced lines. Each connection allows the piping section to be depressurized and the energy to be safely relieved prior to maintenance.

The drain/vent connections provide a method of relieving the high-energy fluid from the lines so that 11 AOVs may be more safely maintained. This minimizes the potential for personnel burn injuries.

The addition of the connections does not change the FSAR, Technical Specifications, or prior NRC commitments. The new connections comply with requirements of USAS B31.1-1967 (as reconciled with ANSI/ANSI B31.1-1986 with addenda) and other original piping system design requirements. The installations are non-seismic, non-QA and non-safety-related. (SER 92-073-02)

18. MR 90-164, (Unit 2), Radiation Shielding. MR 90-164 reduces personnel radiation exposure during work on the RV head and its appendages. Significant levels of radiation exposure (≈20 man-Rem) are incurred from RV head work during each refueling outage. Radiation exposure occurs during removal/installation of RV head insulation, detensioning of the RV head studs, disassembly/reassembly of the conoseals, storage of the RV head in the laydown area, etc. During plant operation, the shielding panels are stored at a designated location in containment El 66' in stainless steel lined storage boxes during plant operation.

Summary of Safety Evaluation: FSAR Chapter 14 analyses are not affected by the change. The addition of the new RV head shield structure does not affect safety-related systems or components, or equipment required to attain safe shutdown of the plant following a design basis accident. The permanent shielding ring is designed to withstand normal operating and safe shutdown loading conditions. This includes performance of a structural seismic review. Installation is completed while the plant is in cold shutdown and has no effect on the probability of an accident.

The integrity of the RCS pressure boundary is not changed. The capability to shut down the reactor and maintain it in a safe shutdown condition is not affected. The RV head is not affected by the additional weight. The permanent shielding ring is designed to maintain its structural integrity during a safe shutdown earthquake. The permanent support structure does not compromise or impede the functionality of safety-related components/structures in the vicinity in the event of a safe shutdown of the reactor.

No fission product boundaries (e.g., fuel cladding, containment and reactor) are degraded by this change. A finite element analysis performed on the lifting rig structure reviewed the effects caused by the addition of the permanent shielding structure.

The shielding blankets are removed prior to the RV head lift due to the crane capacity. They are reinstalled when the RV head is in the laydown area. The permanent addition of the RV head shielding ring contributes ≈2000 lbs to the weight of the RV head; therefore, affecting the total weight lifted by the polar crane. This represents $<1\%$ to the total weight of the RV head and remains below the rated polar crane capacity of 200,000 lbs. RMP 96 documents the use and limitations of the RV head shielding system. (SER 94-042)

19. MRs 90-260, (Unit 1) and 90-261, (Unit 2), Residual Heat Removal System. The modifications resolve seat leakage occurring through 1&2SI-854A and 1&2SI-854B check valves. The new design uses a soft resilient type seating surface attached to the check valve disc. The new resilient seats allow the disc to seal better than the existing metal-on-metal seal, therefore reducing seat through-leakage to acceptable levels. The soft seat material is an ethylene-propylene compound, EPDM, with properties that withstand the design conditions of the valves and the residual heat removal (RHR) system.

Summary of Safety Evaluation: The SI-854A&B check valves are considered to be part of the RHR pressure boundary which is pressure tested according to TS 15.4.4.IV.A.1.a. Backleakage across the valve seat is also measured during this pressure test According to FSAR 6.2-25, acceptable leakage across the disc of a 300 lb check valve exposed to recirculation flow is 10 cc/hr per inch of valve diameter, or 100 cc/hr in this case.

The installation is performed during U1R21 with the cavity flooded with the upper internals removed and the second train of RHR available. This addresses the necessity of having two trains of decayed heat removal (DHR) available when one train of RHR is out of service.

Post-installation leak testing is performed. The replacement of the check valve disc does not decrease the reliability of the check valve to perform its intended function. This type of ethylene propylene resilient seat is already in use and performs satisfactorily in our auxiliary feedwater systems. Normal operating temperature and pressure conditions are very similar to the auxiliary feedwater system conditions. Under certain conditions such as during a refueling outage, the SI system temperature may increase. However, the expected temperatures are within the design parameters for which these resilient seats have been specified. (SERs 94-012, 94-012-01)

20. MR 90-261, (Unit 2), Residual Heat Removal System. MR 90-261 resolves seat leakage occurring through 2SI-854A and 2SI-854B check valves. The work scope changes the old metallic disc in the two valves. The new resilient seats allow the disc to seal better than the old metal-on-metal seal. This reduces seat through-leakage to acceptable levels. The soft seat material is an ethylene-propylene compound (EPDM) with properties that withstand the design and operating conditions of the valves and RHR system. The design of the system is 600°F and 600 psig. The valves are also exposed to boric acid and gamma radiation. The new discs can withstand these environments.

Summary of Safety Evaluation: The SI-854A&B check valves are part of the RHR pressure boundary that is pressure tested according to TS Section 15.4.4.IV.A.1.a. Backleakage across the valve seat is also measured during the pressure test. According to FSAR Section 6.2, acceptable leakage across a disc of a 300 lb check valve exposed to recirculation flow is 10 cc/hr per inch of valve diameter, or 100 cc/hr in this case.

Installation is performed during U2R20 when the cavity is flooded and he upper internals are removed. The second train of RHR is available for use. This addresses the necessity of having two trains of decayed heat removal available when one train of RHR is out of service.

Post-installation leak tests are performed. The replacement of the check valve disc does not decrease the reliability of the check valve to perform its intended function. (SER 94-012-01)

21. MR 91-054, (Common), Computers. MR 91-054 improves the quality and efficiency of the data link between the PPCS (real and simulated) and the emergency operating facility (EOF). Electrical interference with long wire cable runs was producing errors and delays in transmission. The poor signal quality could hamper efficient decision making in the EOF during an incident. Instead of sending commands over long wire cables to a display generator at the EOF, the new configuration generates the graphics in the computer rooms (real and simulator) and sends this signal over fiber-optics to the EOF. The change avoids the electrical interference in the long wire cable runs and greatly improves the reliability of the EOF PPCS/SAS displays.

Summary of Safety Evaluation: The modification alters the design and operation of the plant computer system as described in the FSAR, but does not affect the description of the computer system. The change enhances the performance of the existing EOF displays.

Although some equipment is removed from service for brief periods during the installation, there is sufficient redundancy and diversity in the design of the computer system. The installation is controlled such that both units have access to SAS/PPCS displays at all times during the installation. In addition, FSAR 7.7.5 states: "The plant design includes adequate instrumentation to provide the operator with sufficient information for proper and safe operation at all times, regardless of the availability of the computer system." NUREG-0696 states that planned computer system outages may be performed provided steps are taken to ensure that the SAS/PPCS displays in the control room, EOF, and technical support center (TSC) are available within 30 minutes. Installation is conducted so the SAS/PPCS displays are available within 30 minutes. (SER 94-032)

22. MR 91-116*D, (Common), New Diesel Generators. MR 91-116*D adds two additional EDGs. The EDGs require control in the control room on MCB C02. The modification installs the new G03 EDG subpanel and analyzes connections for the G05 combustion turbine ammeter and wattmeter circuits.

Summary of Safety Evaluation: An insignificant increase in the potential for electrical system problems while working on cutting the control board does exist. This increase in potential for problems is procedurally controlled.

Temporary blockage of instrumentation on C02 MCB exists while cutting the control board. The blocked instrument(s) are read by moving personnel and/or equipment so as to not interfere with normal operations or accident mitigation. Components and their mounting are seismically analyzed utilizing the SQUG methodology. The components are mounted to assure that no seismic interaction hazards within the panels are created in the final design. The seismic analysis for C02 MCB front panel verifies seismic qualifications of the panel with the added components. The seismic qualification is not reduced. Wire is SIS insulation fire rated in accordance with IEEE-383. (SER 93-025-07)

23. MR 91-116*E, (Common), New Diesel Generators. MR 91-116*E installs 1" branch lines and isolation valves downstream of existing fuel oil valves FO-32 and FO-33.

Summary of Safety Evaluation: The new 1" branch lines are the same size as the old lines. The new piping and valves are made of compatible materials and are physically located in the same rooms. Installed piping is pneumatically tested prior to returning the system to service. The new configuration analysis assures that the branch connections and bales are adequately supported. The modified piping configuration allows for the tie-in of fuel oil storage tank T175A to the G01 and G02 fuel oil systems.

Installation of the underground piping does not affect operating systems. The new components are consistent with the types of equipment important to safety currently evaluated in the FSAR. Precautions are taken to control dust and debris in the construction areas and assure construction activities have no affect on operating equipment. The actual pipe tie-in to the existing fuel oil system is completed with the engine fuel oil transfer system out of service. The tie-in to either fuel oil system has no affect on the fuel oil system of the other engine. (SER 93-025-09)

Summary of Safety Evaluation: This safety evaluation supersedes SER 93-025-09 in its entirety. The final configuration of the piping does not require additional supports. However, one support is installed on each pipe run to facilitate disassembly of the flange at the floor in each room. This also limits the horizontal movement of the pipe due to the HDPE liner installation. (SER 93-025-15)

24. MR 91-116*N, (Common), New Diesel Generators. MR 91-116*N rearranges the C02 annunciator window layout to accommodate future G03 and G04 EDG annunciators. The rearrangement includes the elimination of four existing annunciator windows for G01 and G02 EDG "lube oil temperature" and "start system disable" by merging the inputs with the respective common trouble alarm for G01 and G02 EDGs. The change also adds G03/G04 MCC and fuel oil control switches for future use. To optimize the layout of fuel oil controls, the old control switch for FO-3923 (emergency fuel oil tank inlet control valve) is repositioned.

Summary of Safety Evaluation: Wires are SIS insulation fire rated in accordance with IEEE-383. Components and their mountings in the panels are seismically analyzed utilizing the SQUG methodology. Components are mounted to assure that no seismic interaction hazards within the panels are created in the final design. The panels are seismically analyzed to verify that seismic qualification of the panel with the added components is not reduced.

Interim system configurations occur during installation and testing. Annunciator windows are disconnected one at a time. No system configuration indication (lights or metering) associated with affected systems are lost. Operations personnel are notified each time an annunciator is removed from

service. Based upon past control board modifications, the vibration experienced during the cutting and drilling of C01 and C02 are not expected to cause a malfunction of any adjacent control board equipment.

FSAR 8.2.3 describes the EDG function of FO-3923, "An additional supply of diesel oil is maintained on the site in two 60,000 gallon storage tanks to supply the gas turbine and heating boilers. This oil can be transferred by a gravity feed to the 12,000 gallon underground emergency storage tank." While remote control of this function is disabled during the work, the capability to perform the function is maintained. The EDG day tanks and emergency tank are capable of running both EDGs for over 24 hours. This time is sufficient to restore remote control or manually reposition valve FO-3923. Level indication and annunciator for the emergency fuel oil tank is not affected by the work. (SER 93-025-18).

25. MR 91-116*R, (Common), New Diesel Generators. MR 91-116*R installs raceways with associated supports in safe shutdown areas, such as, the vital switchgear equipment room, AFP room, cable spreading room, central and north auxiliary buildings, and the yellow inverter room. The raceways terminate in existing safety-related equipment (e.g., dc distribution panels D02, D04 and D31, safeguards racks 1C157 and 2C167 station service transformers 1X14 and 2X14, 4160 V vital switchgears 1A05, 1A06, 2A05, and 2A06, G02 local transfer panel C35A, and ESF test racks 1RK-59A and 2RK-59A) as well as non-safety-related equipment (e.g., non-vital switchgears 1A04 and 2A04, fire detection terminal box 1TB-69, and 24 Vdc power panel for fire detection D400). The raceways are for both the safety-related and non-safety-related power and control cables for the EDG addition project.

Summary of Safety Evaluation: This work and the final configuration does not affect equipment in a manner which could initiate an accident or the function important to safety structure, system, or component in affected areas. Furthermore, design and analysis of affected safety-related structures ensures system functionality in accordance with licensing requirements.

The equipment to which the raceways is attached is needed to mitigate the consequences of an accident. Appropriate precautions were taken to prevent damage of safe shutdown equipment during installation. The installation requires that equipment which is in an interim installation condition be secured in such a manner as to provide overall structural stability. The raceways are installed as safety-related, Seismic Class 1 and meet Code requirements. As an alternative, some raceways are installed to meet SQUG requirements. (SER 93-025-11)

26. MR 91-116*S, (Common), New Diesel Generators. MR 91-116*S modifies the fire detection system to alarm and monitor the fire detection for the new G03/G04 EDG building and Warehouse #4. The design change includes installing new fire detection panels, raceways, and cabling; installing a new input zone panel (IZP) in panel D-400; modifying the old graphics annunciator panel C-900 to display new fire zones; and, provides the interfacing connections between the local fire detection equipment for the new EDG building, Warehouse #4 and existing plant.

Summary of Safety Evaluation: The cables are procured to meet the flame retardancy requirements specified in the FPER (e.g., IEEE-383 flame test) with the exception of the fiber optic cable (FP5596M). This cable is constructed of high density polyethylene that does not contain a flame retardant rating. However, since this non-current carrying cable is run in conduit and coiled in enclosed panels, this cable does not pose a self ignition or combustible hazard.

Automatic, early warning, smoke and heat type fire detectors and sprinkler flow alarms are installed in the new EDG building. The signals are connected to the new EDG fire detection system control panel D-418 and the local graphics annunciator panel C-934. During the tie-in of the fire detection modifications, the D-400 control panel and its associated graphics annunciator panel C-900 are tagged out of service for approximately one shift. This removes control room indication of the fire detection system for the entire plant. TS 15.3.14.B.1.b states, "The control room annunciation for the fire detection system may be inoperable provided that within one hour of determining the condition, the

area control panels for each area listed in Table 15.3.14-1 are surveyed hourly." The requirement is specified in IWP 91-116*S2. The fire detection system in the EDG building and Warehouse #4 is tested following this modification. (SER 93-025-19)

27. MR 91-116*V, (Unit 2), New Diesel Generators. MR 91-116*V provides preparatory work for the addition of two new EDGs. The work is performed prior to U2R20. The work scope includes providing a permanent source of safety-related dc power from bus D-04 to the G04 and 2A06 dc auxiliaries through panel D-28 and D-40; providing an additional input to the SW pump start circuit from the G04 output breaker 2A52-93; sparing out 2A05/06 bus tie breaker 2A52-72; and installing control switches, internal wiring, and termination of cables in the control board panels for subsequent design work associated with MR 91-116.

Summary of Safety Evaluation: The D-28 and D-40 panels are procured, installed and tested to meet or exceed the requirements for the existing dc system. Calculation UE&C 6704.001-C-067 documents the acceptability of the mounting details for panels D-28 and D-40. The panels are analyzed utilizing the SQUG methodology to verify the panels are seismically qualified to function during and after a safe shutdown basis earthquake. Calculation N-94-021 justifies the addition of loads on bus D-04 resulting from this work. The calculation determined that the revised system design is acceptable from a load flow and voltage drop perspective for the D-04 to D-28/40 configuration.

The D-28 and D-40 panels and their operating alignment under this scheme are installed to meet the train separation requirements of the plant during all phases of the installation, including final configuration. Circuits on panel D-28 associated with the G03 and 1A06 auxiliaries not tested are isolated to eliminate interactions with the dc system.

The only postulated failure of the change to the SW pump start circuit is the unintentional start of the SW pumps due to the accidental shorting of contacts or the accidental closure of breaker 2A52-93 that does not affect the equipment capability to perform its safety function. Post-installation testing verifies the acceptability of the circuit change. Control of the G04 output breaker 2A52-93 is administratively ·rolled. This prevents unexpected challenges (e.g., unwanted starts of the SW pumps) to safety s ns. The post-installation configuration of the SW pump start circuitry meets the design, material and construction standards applicable to the SW and EDG systems.

The only function changed in the FSAR is the removal of the 2A05/06 bus tie capability (breaker 2A52-72). FSAR Section 8.2.1 states, "The bus tie breakers (1A52-61, 2A52-72, 1B52-16C and 2B52-40C) are supplied to facilitate maintenance of the normal supplies to the respective buses. Breakers 1A52-61 and 2A52-72 have been physically removed from the cubicle and placed in storage outside the safe shutdown area." The change removes the capability to crosstie the 2A05 and 2A06 buses. However, this capability is only used for maintenance and is not required for normal operation, or to mitigate an accident.

Terminal points are checked before termination of pre-outage cables in the control board. This verifies that no cables are terminated on the external side of the terminal blocks. The terminal block sliders are then opened to prevent interaction between the new cables and existing internal wiring. The conductors are then landed at the respective terminal points. In addition, the control board work requires cutting for installation of a new control switch. Installation procedures prevent the degradation of existing structures and components (e.g., vibration, foreign material exclusion) resulting from installation activity and the final configuration. (SER 93-025-21)

28. MR 91-116*W, (Unit 2), IWPs 91-116*W1, and *W3-12, 4160 V System. MR 91-116*W and associated IWPs control the EDG work performed during U2R20. The work completes Phase 3A of MR 91-116 that ties in the G04 EDG as the Unit 2 Train B standby emergency power source. The old 4160 V Unit 2 Train B bus 2A06 is abandoned in place. The new 2A06 bus connected to G04 is tied into the existing normal offsite power supply bus 2A04 for Unit 2 Train B safeguards power, and is also tied into the existing 480 V safeguards bus 2B04 for Unit 2 via the 2X14 transformer. 2P15B SI pump is disconnected from the old 2A06 bus and connected to the new 2A06 bus. G02 EDG is then the Unit 1 Train B standby emergency power source and G01 EDG remains unaffected as the Train A standby emergency power source for both units.

Summary of Safety Evaluation: The previously evaluated accidents or transients applicable to the EDG tie-in activities are a loss of offsite power (LOOP), a loss of electrical load to Unit 1, or a Unit 1 trip. During most of the activities associated with the G04 EDG tie-in, Unit 2 is defueled. The exception to this is the 2P15B SI pump swapover, and some minor control board work involving wire labeling and wiring indication lights for circuit breakers F52-142 (Unit 2 generator output breaker) and H52-30 (H03 supply breaker from 2X03). These activities can begin with Unit 2 in a hot shutdown condition. The SI pump work is done when the SI pump is no longer required by TS and while the breakers are tagged out. Thus, the work has no impact on offsite power to Unit 2. TS 15.3.2.A requires a boric acid injection path with fuel in the RV. This is met by having a charging pump, the other SI pump, or another boric acid makeup source available. The generator output breaker indication light has no impact on offsite power while the generator is offline. The H03 supply breaker work has the potential to affect offsite power to Unit 2, but is scheduled when the 2X04 transformer is out of service for tap changes. During the 2X04 tap changes, 1X03 and 1X04 supply offsite power to both units. Therefore, although the risk of tripping this breaker is minimal (sliders in the control board are opened) there is no impact on offsite power if the breaker opens.

The electrical switching activities that take the 2A04 and old 2A06 buses out of service and tie the 2B03/2B04/2B02 buses together have no impact on Unit 1 operations. Offsite power is available to Unit 2 through the Train A buses 2A03, 2A05, and 2B03. Unit 2 is defueled with the core in the SFP and the electrical load is controlled. One train of SFP cooling is powered from 2B03 and the other from 1B04. Single train SFP cooling capability is a requirement for the 2B03/2B04 bus tie. The SFP cooling lineup is to the Unit 1 1B04 powered train of cooling with the 2B03 supplied train isolated but available. Thus the probability of losing SFP cooling or offsite power is not increased. In addition, precautionary measures restrict certain electrical work during the LCO when the Unit 2 buses are tied and out of service. The restrictions include no 345 kV; 13.8 kV or Unit 2 2A03, 2A05, 2B03 bus relay calibrations; G05 be in a high state of readiness; both units X03 and X04 transformers are in service; and, 3 of the 4 345 kV lines be in service. These measures give additional assurance that offsite power is maintained.

Some of the control system work performed via the IWPs has the potential to affect Unit 1. Work is done in the Train B safeguards rack 1C167. This involves removing a G02 EDG auto start signal on a Unit 2 SI signal. Appropriate care is taken when working in the racks to prevent affecting Unit 1 or equipment important to safety. Double verification steps ensure the correct lead is worked on.

During the Unit 2 core offload, three LCOs are entered: 1) An emergency power LCO for G02 EDG operability for Unit 1 based upon TS 15.3.7.B.1.h; 2) P38B AFP LCO based upon TS 15.3.4.C.2; and 3) 2B03/2B04 safeguards bus crosstie LCO based upon TS 15.3.7.B.1.d & e. The emergency power and AFP LCOs are a 12-day duration. The crosstie LCO has no duration, but requires the Unit 2 core to be offloaded to the SFP and electrical load is controlled. During the LCOs the single failure requirement for the affected systems is relaxed. This means that a failure of a redundant AFP does not have to be postulated to ensure an accident or malfunction of equipment on Unit 1 can be mitigated.

In addition to meeting the licensing basis for required equipment during the 12-day LCO period, additional compensatory measures and contingency actions provide assurance that redundant means are available to mitigate an accident on Unit 1. These include the fact that after the *W3 design package (removing Unit 2 SI signal to G02) is complete, and G02 EDG is available to Unit 1. G02 EDG is technically inoperable for Unit 1 accident mitigation because only 1 SW pump is able to be powered by G02. Calculation N-94-102 demonstrates the capability for G02 EDG (with 1 SW pump) to be able to supply enough SW flow to mitigate a LOOP and a failure of G01 EDG with a Unit 1 trip. The calculation contains a contingency that SW to the SFP cooling be isolated within 10 minutes to prevent damage due to SW pump runout. This is possible by having the SFP cooling train in service that is powered from 1B04. This ensures SW can be isolated from the control room in the time required.

Station blackout commitments continue to be met during the activities because G05 combustion turbine remains operable throughout the tie-in process. Appendix R concerns are administratively controlled through a twice per shift fire watch during the time P38B AFP is out of service. (SER 93-025-22)

Summary of Safety Evaluation: This safety evaluation supersedes SER 93-025-22 in its entirety. In addition to meeting the licensing basis for required equipment during the 12-day LCO, additional compensatory actions provide additional assurance that redundant means are available to mitigate an accident on Unit 1. These include the fact that after the SI portion of the 91-116*W3 design package, G02 is available to Unit 1. (SER 93-025-23)

29. MR 91-135*A, (Unit 2), Main Steam System. MR 91-135*A replaces 2MS-2015, steam generator "B" atmospheric steam dump valve, with a Copes Vulcan 600 lb. globe valve.

Summary of Safety Evaluation: The new valve is similar to the old except for the trim design. The new valve has a balanced plug that balances the pressure differential on the valve plug to eliminate problems with the valves failure to open. The cage is designed to give the valve a better throttling characteristic in the 10-20% flow range for improved controllability. The new valve trim configuration reduces steam cutting and prolongs the life of the valve trim. The valve is installed and operability and leak tight tested. If the valve operates acceptably, the three remaining valves will also be replaced.

The atmospheric steam dump lines must be operable because they are relied upon for RCS cooldown to RHR conditions following a SG tube rupture coincident with a loss of ac power. An atmospheric steam dump line is considered operable if it is capable of providing the controlled relief of main steam flow necessary to perform the RCS cooldown. Isolating an atmospheric steam dump line does not render it inoperable if the line can be unisolated. Also, the RCS can still be cooled to RHR entry conditions through local or remote operation within the time period required by the applicable FSAR accident analyses. The valve replacement reduces the frequency and duration of having a steam dump path out of service.

During installation, containment closure requirements are maintained by closing the manual isolation valve. The valve is tagged shut and maintained in that position until the installation and testing is complete. (SER 94-034)

30. MR 92-089*A, (Unit 1), Safety Injection. MR 92-89*A removes the automatic open safety injection (SI) signal on the boric acid storage tank (BAST) suction line valves.

Summary of Safety Evaluation: The design changes the refueling water storage tank (RWST) as the initial source of safety injection (SI) system fluid, instead of the boric acid storage tank (BAST). The original design automatically used the BAST as the original source of SI fluid. Analyses performed provide the justification for discontinuing the use of the BAST as the initial source of SI fluid.

The SG tube rupture analysis states that the RCS is borated by the high head safety injection pumps (HHSI). It also states that ≈92,485 lbs of reactor coolant is discharged to the secondary side of the faulted steam generator. If all 92,485 lbs are made up by the high head SI system, it needs to provide ≈11,158 gallons. This should be sufficient to borate the reactor for cold shutdown using only 2000 ppm RWST fluid.

The radiological consequences of the steam generator tube rupture accident are not affected if the BAST is not used.

The steam pipe rupture analysis states that the core is ultimately shut down by the boric acid in the SI system. FSAR 14.2.5 also states, "Minimum safety injection capability corresponding to one out of two safety injection pumps in operation. 20,000 ppm boron is assumed in the safety injection system. The time delays required to sweep the low concentration boric acid from the safety injection piping prior to the delivery of the 20,000 ppm boron have been included in the analysis."

Nonconformance reports N-89-286 and N-89-346 cast doubt on the availability of 20,000 ppm boric acid in the SI system. The SI system boron concentration can be expected to be at least 2000 ppm because of the large amount of fluid available in the RWST with this concentration. WCAP-12602, "Report for the Reduction of SI System Boron Concentration," shows that the results of this reanalysis are acceptable.

The following statements in FSAR 14.3.1 pertain to SI system boric acid injection for a small break LOCA: "Reactor trip and borated water injection complement void formation in causing rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures."

WCAP-12602 states that the use of 2000 ppm boric acid solution for the small break LOCA analysis does not adversely affect the licensing basis results.

WCAP-12602 states that the peak LOCA hydraulic forcing functions are seen within the first 500 milliseconds following the break initiation. Since the duration of the event is substantially shorter than the time required to initiate SI flow, the BAST and SI systems are not modeled in this analysis. Therefore, the use of 2000 ppm boric acid in the SI system does not affect the results of the LOCA hydraulic forces analysis.

The containment integrity evaluation is based upon the mass and energy released to containment during a LOCA. SI fluid from the RWST has a lower enthalpy than fluid contained in the BAST, because the highly concentrated acid in the BAST is maintained above 145°F. Therefore, the results of this evaluation do not adversely affect the use of the 2000 ppm boric acid from the RWST.

FSAR 14.3.2 analysis proves that the emergency core cooling system performs to maintain the core coolable and in place. The analysis of environmental consequences of a LOCA assumes the entire inventory of volatile fission products contained in the pellet-cladding gap released during the time the core is being flooded by the emergency core cooling system. Of this gap inventory, 50% of the halogens and 100% of the noble gases are assumed to be released to the containment vessel atmosphere. These conservative assumptions are not affected by the use of 2000 ppm boric acid from the RWST in the high head safety injection system. <u>(SER 90-128)</u>

31. MRs 92-089*B1 and 92-089*B2, (Unit 1), Safety Injection System. MRs 92-089*B1/B2 and 92-147 allow both Unit 1 Train A and B safeguards to have 125 Vdc control power secured.

Summary of Safety Evaluation: The modifications allow for both Unit 1 Train A and B 125 Vdc safeguards control power to be secured from the time the RCS reaches 200°F until the RV head lift begins. The automatic functions that are not available include safety injection (SI), (containment isolation due to a SI or high containment pressure signal); and the containment purge supply and exhaust isolation (due to a high radiation signal from containment.) The SI signals are normally blocked during cold shutdown. CIVs can manually be operated from the control room. CL-1E is used to determine which valves need to be manually controlled. The containment purge isolation from a high radiation signal is required during fuel motion. This function is ensured by restoring a train of 125 Vdc safeguards control power prior to RV head lift.

Unit 2 safeguards equipment is functional. Unit 1 125 Vdc safeguards control power is secured from the time the primary RCS is below 200°F until the RV head lift begins. The automatic functions are not needed or required during the time that both trains of Unit 1 125 Vdc safeguards control power is secured. The normal SW pump start on a Unit 1 undervoltage signal is disabled. However, Unit 2 powered P32D-F SW pumps are run to preclude any effects on normal SW operation due to a loss of power to Unit 1. The SW pumps start on a Unit 2 undervoltage signal or a Unit 2 SI signal, therefore SW system operability for Unit 2 is not impaired. The other shared safeguards load P38B AFP also starts on a Unit 2 SI signal. Thus the consequences of an accident are not increased.

Containment penetrations that lose their automatic isolation are noted on CL-1E. The ability to isolate the containment before the RCS "time-to-boil" is maintained during the work. (SER 94-009-01)

32. MRs 92-090*B1 and 92-090*B2, (Unit 2), Safety Injection System. The modifications remove the high head safety injection (HHSI) pumps automatic switchover circuitry.

Summary of Safety Evaluation: Each train of the Unit 2 safeguards control power is isolated so the components located in the safeguards racks can be removed. Only one train of Unit 2 safeguards control power is isolated at a time. Unit 1 safeguards control power is not affected by the work. Each valve is electrically isolated while changes are made to the valve control circuitry.

The removal of the circuitry for this switchover function does not cause any safety concerns since the components are no longer necessary for plant safety. The continuity of wires installed to complete the daisy chain of safeguards control power is verified to ensure no piece of equipment is left without power. ORT 3 and 6 tests, along with the safeguards logic test, also verify that safeguards control power is not broken. Therefore the probability of an accident or malfunction of equipment important to safety is not increased either during or after installation.

One train of the Unit 2 safeguards control power is electrically isolated during the removal of the safeguards logic circuitry. Circuits that use the safeguards automatic sequencing of loads onto the buses still have manual operation available. Only one train of Unit 2 safeguards control power is out of service at a time. The work is performed during cold shutdown so the SI timing application for safeguards is not necessary. SI signals are normally blocked during cold shutdown. SW availability is the limiting case during installation. The normal SW pump start on Unit 2 undervoltage is disabled for the Unit 2 train worked on because the Unit 2 undervoltage sequencing uses the Unit 2 applicable train SI time delay relay that is out of service. Therefore, 1P32A-C SW pumps are running to preclude any effects on normal SW operation due to a loss of normal power to the Unit 2 bus whose SW pump time delay relays worked on. The affected SW pumps still start on a Unit 1 undervoltage signal or a Unit 1 SI signal. Therefore, SW system operability for Unit 1 is not impaired. The other shared safeguards load, P38B AFP, also starts on a Unit 1 SI signal.

When either train of safeguards control power is out of service, containment penetrations which cannot be isolated by the other train of safeguards alone are noted on CL-1E, Attachment A. The ability to isolate containment before the RCS "time-to-boil" is maintained. (SER 93-069)

33. MRs 92-099, (Unit 1) and 92-100, (Unit 2), CVCS. The modifications replace the existing transmitter with new Rosemount differential pressure transmitter/orifice plate assemblies. New power supplies are installed at the transmitter locations and powered by the existing transmitter ac supplies. New Yokogawa recorders are installed in the C04 main control boards due to the 4-20 ma signals generated by the new transmitters.

Summary of Safety Evaluation: The new transmitters have the same low flow (0-1 gpm) and normal flow (0-6 gpm) range as the old transmitters. The new installation determines flow via differential pressure supplied by an inline orifice instead of a mechanical inprocess float. The new Rosemount Smart transmitter provides significantly more accurate and repeatable results compared to the old instrumentation. The new Smart transmitter provides the capability of calibrating the new transmitters anywhere along the instrument loop. This allows the loop to be calibrated or checked outside of the containment during normal operations.

The changes are non-safety-related, QA-scope work performed during a refueling outage. However, the piping associated with the modification is considered safety-related, Seismic Class 2. The leakoff line maintains the pressure boundary of the RCS in the event the first stage seal fails. Transmitters, flow orifices and valve manifolds are specified to maintain the pressure boundary. Instrumentation and its associated indication functions are non-safety-related.

The modification does not require deenergization of instrument racks 1&2C125 and 1&2C126. Therefore, the modification does not affect other instrument loops in the racks. Power is disconnected from the old transmitters and control board recorders. Isolation of piping between valves 1&2CV-293A and 1&2CV-385A for P1A RCP and valves 1&2CV-293B and 1&2CV-385B for P1B is required. (SERs 94-023, 94-023-02)

Summary of Safety Evaluation: This safety evaluation replaces SER 94-023 in its entirety. SER 94-023 incorrectly referenced the piping associated with MR 92-099 as Seismic Class 2. The correct reference is Seismic Class 1. (SER 94-023-01)

34. MR 92-123, (Common), Spent Fuel Pool. MR 92-123 installs a disconnect switch for the SFP bridge. The disconnect switch is installed between the power supply for the bridge (PP2-10) and the main line contractor that isolates power from the circuitry. The disconnect locally ensures that no power is supplied to the SFP bridge, hoist, and hoist trolley.

Summary of Safety Evaluation: MR 92-123 gives the SFP bridge operator the ability to secure power locally at the bridge. Previously the operators had to go to El 46' from El 66' to secure power at PP2-10 if a problem occurred causing the main line contactor not to open. The ability to secure power locally reduces the possibility of a fuel handling accident in the SFP.

The modification installs the disconnect switch, conduit to the disconnect switch, and wires the switch. The disconnect switch and conduit are mounted per manufacturer specifications. The disconnect switch can be locked in the open position to prevent switch movement during a seismic event. The SFP bridge is not available during installation. (SER 92-085)

35. MRs 92-147, (Unit 1) and 92-148, (Unit 2), Safety Injection. The modifications replace the Unit 1 and 2 safeguards timing relays which are used to sequence loads on the vital buses during a loss of power or safety injection (SI) signal.

Summary of Safety Evaluation: The replacements with newer Agastat ETR solid-state timing, mechanically actuated relays gives the plant a more reliable timing relay in this safeguards application. The failure modes are similar for both the old and new relays in that they both may fail by operating too early, too late, or not at all. The electro-pneumatic relay timing failures could be caused by a pneumatic problem. The ETR relay timing problems could be caused by a solid-state problem. While the failure methods may be different, the failure modes are the same. The older pneumatic timing relays are prone to drift in infrequently actuated applications. The repeatability timing is $\pm 5\%$ for both relays. However, testing has shown the new ETR relays to operate within a smaller band.

The new Agastat ETR relays are procured as Class 1E, safety-related equipment. The relays are used in similar applications at other nuclear plants and are more reliable than the older pneumatic timed relays. The relays are used to sequence loads onto the EDG after a loss of power or a SI signal. The relays cannot cause an accident or malfunction of equipment important to safety since their only purpose is to start loads after an accident that initiates from a SI signal or a loss of power. Unit 1 safeguards equipment is available for manual operation during installation. The only malfunction that could occur during installation is the unnecessary starting of a safeguards controlled piece of equipment. This does not place the shutdown unit in risk since the equipment can quickly be secured if not needed.

One train of safeguards control power is electrically isolated during the installation of the new relays. Circuits that use the safeguards automatic sequencing of loads onto the buses still has manual operation available. Only one train of safeguards control power is out of service at a time. The work is performed during cold shutdown so the SI timing application for safeguards is not necessary. SI signals are normally blocked during cold shutdown. SW availability is the limiting case during installation. The normal SW pump start on undervoltage is disabled during the time the safeguards train is worked on since the undervoltage sequencing uses the applicable train SI time delay relay which is out of service. However, the opposite unit powered SW pumps P32D-F are run to preclude effects on normal SW operation due to a loss of normal power to the bus whose SW pump time delay relays are being worked on. The affected SW pumps start on a the opposite unit undervoltage signal or an opposite unit SI signal, therefore SW system operability for the applicable unit is not impaired. The other shared safeguards load, P38B AFP also starts on an opposite unit SI signal.

Since the new replacement relays operate and fail in a similar manner to the old relays, an accident or failure caused by the malfunction of these relays is unchanged. The only problem that could occur during installation is the accidental starting of a safeguards controlled component. The starting of one of these loads does not cause a safety problem and could be quickly secured if the load is not required. Thus the possibility of an accident or malfunction of equipment important to safety not previously evaluated is not increased.

When either train of safeguards control power is out of service, containment penetrations which cannot be isolated by the other train of safeguards alone are noted on CL-1E, Attachment A. The ability to isolate the containment before the RCS "time-to-boil" is maintained during the modification. The margin of safety for SW operability per TS 15.3.3.D is not degraded. (SERs 94-010, 93-070)

36. MR 93-031, (Unit 2), CVCS. MR 93-031 adds a 3/4" test connection and root valve, 2CV-369C, upstream of 2CV-369A in the 2" RHR to CVCS crossconnect piping to support seat leakage checks on 2CV-369A.

Summary of Safety Evaluation: The test connection is similar to other test connections installed in the CVCS and RHR systems. The test connection is installed using required administrative controls and installation procedures. The materials are compatible to the materials in use in the system. The modification is performed during cold shutdown. Seat leakage testing on 2CV-369A is in accordance with 10 CFR 50 Appendix J requirements. (SER 93-062)

37. MR 93-041*C, (Common), HVAC. MR 93-041*C upgrades the pneumatic controls, pneumatic cooling valve and isolation damper fail positions, RMS auto initiation mode, and emergency filtration ventilation envelope for the control room. The emergency filtration ventilation envelope is all areas which are served by the emergency filtration ventilation system. The revised system operation maintains temperatures in the control room, computer room, mechanical room, and cable spreading room during the system operating modes. The revisions to the HVAC system provide improved temperature controls and reduces the locations for unfiltered inleakage.

Summary of Safety Evaluation: The design package revises the RMS actuation signal from radiation element RE-101 or RE-235 to auto initiate the outside air filtration mode (Mode 4) of the control room HVAC system (the old configuration auto initiated Mode 3, partial return air filtration). The change revises operation of the computer room supply and return air isolation dampers, CV-4849A and CV-4849B, respectively, to remain open during the system operating Modes 1 through 4 (the old configuration isolated the computer room in Modes 2 through 4). The change also revises the supply air source to the mechanical room. By revising the RMS auto initiation to Mode 4, and including the computer room and mechanical rooms in the control room envelope, the locations for unfiltered air inleakage into the control room are reduced. Unfiltered inleakage is reduced because the quality of negative pressure ductwork is reduced, and the area which contains negative pressure ductwork is supplied with ventilation air from the emergency filtration ventilation system. Including the computer room in the control room envelope also ensures cooling air is supplied to the computer room during operating Modes 1 through 4. This serves to maintain temperatures during abnormal operating modes.

The changes increase the inherent reliability and safety of the control room, computer room, and cable spreading room HVAC systems and the associated emergency filtration system by making the systems operable on a loss of instrument air, and by providing an inherently safe lineup of valve and damper positions for operation of the associated emergency filtration system and for cooling supply. The locations of unfiltered inleakage are reduced. The effects of increased control room envelope volume is found acceptable. (SER 94-016)

38. MR 93-047, (Unit 1), Containment Spray System. MR 93-047 upgrades 22 existing piping supports to meet thermal and seismic analysis requirements. Twenty-one of 22 required design changes are required to meet NRC Bulletin 79-14 commitments. The support upgrades include pipe supports on the Unit 1 containment spray (CS), SI, main stream (MS), main feedwater (MFW) and CVCS systems. One of the support upgrades involves the enhancement of an SI valve support that was determined to be inadequately supported as a result of the USI A-46 program. The upgrades ensure that no piping or support component stresses exceed Code allowables.

Summary of Safety Evaluation: The current as-built piping and supports for the SI, CS, MS, MFW and CVCS systems inside Unit 1 containment were evaluated for their ability to withstand the design basis loads and stresses imposed on the systems. The evaluations include both pipe and pipe support stress analyses as part of the NRC Bulletin 79-14 reconciliation program. The results show that while the systems are operable as is, various loading combinations could result in pipe support stresses greater than Code allowable. The stresses are reduced to values below Code allowables via MR 93-047. The current as-built piping and supports and the modifications, as well as the Code

compliance analysis are documented in WE piping system quantification reports 100083, 100086, 100089, 100091, 10093, 100094 and 100104. Code stress allowables for the affected piping and supports are satisfied as a result of MR 93-047.

Temporary support at six of the supports is required to support deadweight loads only. Therefore, the seismic integrity of the systems is not affected. Grinding or welding on the piping is not required, therefore pressure boundaries are not affected by this work. Operability of the piping systems is maintained throughout the installation of the support upgrades. The design changes enhance the affected piping's capability to withstand thermal and seismic loads and are appropriate for the current conditions. (SER 94-025)

39. MR 93-050, (Unit 2), CRDM. MR 93-050 modifies and tests the Unit 2 solid-state rod control system timing.

Summary of Safety Evaluation: The timing change requires repositioning of diodes on the printed circuit boards in the solid-state rod control system logic cabinets. The diode repositioning does not change the functionality or the design of the boards. The timing changes have no impact on normal operation or during any transient. It does not change assumptions made in the safety analysis. The timing changes enhance the reliability of the solid-state rod control system and has no adverse impact on safety-related systems.

The changes to the PC boards in the solid-state rod control system logic cabinets reduce the possibility of asymmetric rod movement during its operation when certain single failures are present. However, the timing change creates some additional failure modes. The new failure modes created are such that a failure of a diode on one of the decoder cards may result in rod motion failure. The failure is only in one direction and depends on what card fails, and at what step in the rod timing sequence the failure occurs. However, no new uncontrolled failures modes are created. All of the controlled failure mode rod movements continue to be within the bounds of the single rod control system malfunction in our licensing basis. (SER 94-046)

40. MR 94-001, (Unit 2), MR 94-001 cuts and caps drain valve 2D-33 (Unit 2 SI/CS test line) because the drain is a source of leakage. A freeze seal of the test return line (6SI-151R-8) to the RWST is utilized during installation. This line ties back into the RWST ≈15' above the bottom of the tank.

Summary of Safety Evaluation: The change to the drain line is made because it is a source of leakage. Welds in the 3/4" drain line have cracks. A possible root cause to the problem is high vibration of the line. Removing the valve significantly reduces the vibration and stress levels on the welds. The drain valve is used for draining the line for repair of the piping as necessary.

The modification (including the freeze seal) does not adversely affect any system, structure or component. During installation Technical Specification required equipment remains functional and operable. In the unlikely case of a failure of the freeze seal, the RWST is not adversely affected because either the leak can be quickly identified, quickly stopped or easily made up to the RWST before TS limits are reached. In addition, leakage through the drain valve into the PAB is well within the capability of the drainage system. (SER 94-001)

41. MRs 94-023, (Unit 1) and 94-024, (Unit 2), Main Steam System. The modifications replace the HX-18A1&2 and HX-18B1&2 steam generator blowdown (SGBD) recovery heat exchangers.

Summary of Safety Evaluation: The new SGBD heat exchangers operate at slightly higher SGBD flow rates during startup conditions. The modification includes changes to system piping and valves, structural supports, rigging for transporting the heat exchangers, reheat tracing for freeze protection, and reinsulating.

SGBD is a function of the volumetric flow rate of blowdown. A greater flow rate of blowdown results in a lower secondary system equilibrium activity if other variables remain constant. If the

primary-to-secondary leak rate, as well as the blowdown rate, remains constant, the number of curies per second exiting through blowdown must also remain constant since the system is at steady state.

Stated another way, the number of curies per second entering the secondary system is constant, a function of the primary-to-secondary leak rate. Therefore, the number of curies per second leaving the secondary system must be the same, otherwise activity is increasing in the secondary system, which is not the case.

FSAR 14.2.4, "Steam Generator Tube Rupture" uses SGBD rate to calculate secondary system equilibrium activity. The radiation released during a SG tube rupture is a function of the secondary system equilibrium activity since some of the water is released. Table 14.2.4-1 lists a blowdown rate of 3.4711×10^3 lb/hr for two steam generators. This corresponds to 55.6 gpm. The total blowdown rate during normal operation for two steam generators is 80 gpm. Since the lower number results in a greater secondary system equilibrium activity (a worse accident scenario), the FSAR calculation is conservative.

FSAR Appendix I also references SGBD and details how radioactive wastes are processed in the effort to keep releases as low as reasonably achievable (ALARA). The average blowdown rate used in the Appendix I calculation is 25 gpm per steam generator, as referenced in Section 2.3. Although this is lower than the normal operating value of 40 gpm per steam generator. This is not an issue because the total number of curies released into circulating water per year is not a function of the blowdown rate.

TS 15.7.3, "Radioactive Effluent Monitoring Instrumentation Operability Requirements", addresses the radiation monitors on the SGBD discharge, blowdown tank, and the SW discharge. The Technical Specification does not contain specific setpoints and refers to the Offsite Dose Calculation Manual (ODCM) for determining these setpoints. The ODCM was updated to reflect the new startup blowdown flow rate. (SER 94-040)

Summary of Safety Evaluation: TS 15.7.3 addresses the radiation monitors on the SGBD discharge, blowdown tank, and the SW discharge. Specific setpoints are addressed in the Offsite Dose Calculation Manual. The replacement of relief valves CS-3108 and CS-3109 protects the shell-side of the SGBD heat exchangers from overpressure due to a tube rupture as required by ASME VIII. The relief valves relieve shell-side pressure by sending flow to the T26 blowdown tank. (SER 94-040-01)

42. MRs 94-029, (Unit 1) and 94-030, (Unit 2), Feedwater System. The modifications replace second-off feedwater check valves, CS-466AA and CS-476AA, from the A and B steam generators. The valves are replaced due to leakage problems.

Summary of Safety Evaluation: The new valves weigh more than the old valves. The added weight is included in a seismic analysis performed for the new system layout.

The original design code for this system was ANSI B31.1-1967 and ASA 16.5. The new valves are designed and tested in accordance with ASME Section III-1974, Class 2, with summer, 1976 Addenda. The new valve design code is equal to the original design, and in many areas more stringent in its design control. The flow function of the valves is also addressed.

There is concern for valve flutter occurring. Calculations show that feedwater flow is not sufficient to raise the disc entirely out of the flow path of the feedwater. Flow will raise sufficiently to not cause a flutter problem with the valve. There is no concern about whether the valve is able to perform its function to open to deliver feedwater to the steam generators as well as to shut and seat properly when auxiliary feedwater is to be delivered to the steam generators.

The ASME Section III requirements for the new valves are acceptable, and exceed in nearly every way, the original check valve requirements. The new valves do not adversely affect the ability of the valves to isolate as containment isolation valves or to assure steam generator pressure integrity.

The new valves are a tilting disc design. The response time of the system is not altered by this installation. The new check valves are a bolted bonnet design which is the same design as the first-off check valves currently in use inside containment. This design allows for ease in future maintenance of the valve. (SERs 94-013-01, 94-013-03)

43. MR 94-033, (Unit 2), Residual Heat Removal System. MR 94-033 welds an angle to the free end of a S-beam to support AC-601R-3-2H6 by anchoring the support to the ceiling of Pipeway #3.

Summary of Safety Evaluation: Residual heat removal (RHR) pipe support AC-601R-3-2H6 is cantilevered off of an embedded channel in the overhead of Pipeway #3. An S-beam is welded to the embedded channel on one end and is free at the other end. The hanger trapeze rods are then attached to the S-beam. The embed rotated due to the applied loading and allowed the free end of the support attachment S-beam to move ≈1" off of the ceiling. This configuration is considered operable. The modification welds an angle to the free end of the S-beam. This ensures the angle is expansion anchored to the ceiling of Pipeway #3 and provides support on both ends of the S-beam. This prevents rotation of the channel embed.

The old spring can hanger support is only considered effective for deadweight support. Therefore, when a temporary support is installed to support the piping during the work, the only forces of concern is the deadweight. The other existing AC-601R-3 pipe supports carry seismic and thermal loading. The change is performed during a non-outage period when the RHR system is not in operation. This reduces the potential for thermal and transient concerns. No work is performed on the pressure boundary of the AC-601R-3 piping. The work does not result in the RHR system being inoperable and does not impact technical specification requirements. The support is located on the containment sump suction line for 2P10A RHR pump just upstream of the tee with the suction from the RWST (just downstream of valve 2-704A).

The interim condition of the modification is short-term. A seismic event does not cause damage to the pressure boundary of the RHR piping. If an accident occurs, the RHR system would function as required with the temporary support carrying the hanger deadweight load. (SER 94-038)

44. MR 94-038, (Unit 2), Service Water System. MR 94-038 modifies 10 SW pipe supports inside Unit 2 containment to meet thermal and seismic analysis requirements.

Summary of Safety Evaluation: The as-built piping and pipe supports for the SW supply and return systems inside Unit 2 containment is evaluated for their ability to withstand the design basis loads and stresses imposed on the system. The results show that while the system is operable as-is, a LOCA imposes thermal stresses on the piping in excess of Code allowable values. These stresses are eliminated with the removal of four stanchion anchors that tie the supply and return headers together. The results of the analysis show furthermore that several pipe support configurations require reinforcement to ensure that no analyzed loads result in support stresses greater than Code allowable. The Code compliance analysis for SW piping is documented in WE Piping System Qualification Report Nos. 200085, 200086, and 200088 through 200097. MR 94-038 satisfies Code stress allowables for the SW piping and supports inside Unit 2 containment. Temporary support of the piping is not required. The piping system remains operable throughout the installation process.

The design changes enhance the SW piping capability to withstand thermal loads without compromising the piping seismic integrity and are appropriate for the current conditions. (SER 94-037)

45. MR 94-041*A, (Unit 2), Safety Injection System. MR 94-041*A cuts and caps drain valve 2D-29 to preclude a fatigue damage repair. The drain line runs from the Unit 2 SI/CS test line piping inside of the Unit 2 facade.

Summary of Safety Evaluation: The drain line is not isolable from the Unit 2 RWST and requires a freeze seal if a repair of the drain line is necessary. The drain line is similar to the other drain line on the SI/CS test line piping that experienced cracking and leakage because of fatigue damage. The drain

line is cut and capped to preclude a fatigue damage repair. The modification is performed during U2R19 while the RWST is drained to allow work without a freeze seal. If the need arises to drain the SI/CS test line, the cap on the drain line is removed.

The work does not require special accessibility considerations. The work is performed inside the Unit 2 facade at El 8'. The work is performed in potential radiation and contaminated areas and requires a radiation work permit (RWP). HP support is provided for work in the facade.

The potential for flooding is not increased because the modification requires the RWST be drained. Removal of the drain valve does not adversely impact the piping stress analysis for the Unit 2 SI/CS test line because it reduces stresses due to the removal of cantilevered weight from the line.

The work modifies safety-related piping and requires QA material. The welders and weld procedure for the fillet weld are certified in accordance with ASME Section IX. (SER 94-039)

TEMPORARY MODIFICATIONS

1. TM 93-030, (Unit 1), Main Steam System. TM 93-030 installs a 5", 600 lb blind, raised face flange in place of the valve bonnet on atmospheric steam dump valve 1MS-2015. The manual isolation valve is used for controlling steam dumping to the atmosphere if required.

   Summary of Safety Evaluation: Replacement of the bonnet with a blank flange is not a safety concern. The flange is a 600 lb rated flange, the same as the original design of the valve being replaced. The flange does not see full system pressure as differential pressure is at the upstream valve. The downstream pressure of this valve is vented to the atmosphere. The flange is installed in place of the valve bonnet for personnel safety if the upstream manual isolation valve needs to be operated. Operation of the system is accomplished through manual operation of the upstream valve. EOP-3.3 and EOP-3 use the manual valve as an available means to dump steam. This allows operation of the piping and flow path for cooldown and depressurization using a steam generator. Use of the valve is controlled by isolating the manual isolation valve shut. The manual isolation valve is only used if considered necessary and appropriate by the DSS. The probability of the valve being stuck open while in use is very small. This occurrence is judged to be similar to other single failures considered in the FSAR. EOPs exist for mitigating such an occurrence. (SER 93-078-02)

2. TM 93-040, (Common), 13.8 kV System. TM 93-040 connects G03 and G04 new EDGs to the 13.8 kV system through the X04 transformer to allow testing the new EDGs under load and provides a source of power for the new auxiliaries and building loads. TM 93-040 connections are removed prior to the final plant tie-in. Breaker manipulation required to load G03/G04 EDGs are procedurally controlled. DSS permission is required for the operation of the H52-15 breaker.

   Summary of Safety Evaluation: The description of the 13.8 kV system in FSAR Section 8.2.2 is not altered by this temporary modification. Although the 13.8 kV system is described in the FSAR, its function is unchanged. The high side of the spare X04 transformer is connected to spare breaker H52-15, which is the intended application (original design function) of this spare breaker. H52-15 is capable of interrupting any fault condition applied to the 13.8 kV system. Relaying is in place to isolate bus H-01 from any fault due to the H52-15, G03, G04, X04S, or any cable connecting the systems. Protective relaying is consistent with existing protective relaying on the system, and is adequate to assure isolation of fault conditions. The protective relaying setpoints are determined based upon the temporary installation configuration. The small load addition and generation capability of new EDGs is within the capability of the 13.8 kV system. Administrative controls prevent the EDGs from being tied to the 13.8 kV system at the same time as G05 combustion turbine.

   Phasing checks and protective relay calibrations are performed prior to high side terminations. Sync checks are performed prior to closing in the EDGs. Adequate fault and overcurrent protection is in place and selective coordination is maintained. Potential failure of equipment installed by this

temporary modification which could affect the operation of the 13.8 kV system is automatically isolated by the protective relaying already in place or installed by this temporary modification. Even if this automatic protection failed, the worst possible scenario is a partial loss of offsite power, which is an analyzed event. (SER 93-025-20)

3. TM 94-003, (Unit 1), Chemical Volume Control System. TM 94-03 replaces AOV 1CV-110C with a manual operator so the air operator for 1CV-110C can either be rebuilt or replaced.

Summary of Safety Evaluation: The manual operator for 1CV-110C is normally maintained shut and is used to prevent dilution of the RCS with reactor makeup water flow to the top of the VCT. The valve is controlled via a 3-position switch on 1C04 MCB which opens automatically when dilute or alternate dilute is selected on the VCT makeup mode selector switch. By replacing the operator with a manual operator, these functions are disabled. During alternate dilute mode of operation, 1CV-110B also opens, which allows the RCS dilution via this mode.

OP-5B describes the operation of various modes of the VCT makeup. The following modes are not affected because the flow path is through 1CV-110B: Manual borate, auto makeup, and manual blend. Dilute mode is not available from the control room without manual action through 1CV-100C. Alternate dilute is affected because 1CV-100C does not automatically open, but in alternate dilute, 1CV-110B also opens so an automatic flow path for dilution is established.

OP-5B contains information for RCS hydrogen concentration. If a batch makeup of ≥2000 gallons or daily makeup of ≥4000 gallons is required, and the entire amount is directed through 1CV-110B, then flow bypasses the VCT and does not pick up hydrogen gas from the VCT. This results in the RCS hydrogen concentration reducing below the required concentration.

An operator aid is placed at the Unit 1 makeup mode selector switch stating that the dilute mode is not available, and in alternate dilute, 1CV-110C does not open. If a batch dilution of ≥2000 gallons or a daily dilution of ≥4000 gallons is required, then alternate dilute is selected and dilution flow through 1CV-100B is established in accordance with OP-5B. 1CV-110C is then locally opened to establish a flow path to the top of the VCT. 1CV-100B is shut via the control switch at 1C04 main control board and the dilution operation is monitored. Prior to adding the entire amount, CV-110B control switch is placed in automatic and the valve is verified open. Then 1CV-110C is locally shut. This method of operation is only to be used for dilution and is only required if the batch or daily limits are reached. All blending operations to the RCS shall be in accordance with OP-5B with the flow path through 1CV-110B.

Since the only function disabled is the dilute mode of operation for VCT makeup and the flow path is still available via local operation for hydrogen control, installation of a manual operator on 1CV-110C does not increase the probability or consequences of an accident.

The manual valve materials are identical to the original air operator. Temperature, pressure, and chemistry are not a concern, as the material is not changed. (SER 94-007)

4. TM 94-012, (Common), Fuel Oil System. TM 94-012 installs two piping supports necessary to support the piping downstream of FO-128 and FO-129 during flushing activities for the underground fuel oil piping installed for MR 91-116 and the EDG project. The piping downstream of FO-128 and FO-129 is normally supported by the flanged connection to the underground piping from the new EDG building. The flanged connection is disassembled during flushing activities. While the flanges are disassembled a jumper is connected to each flange and routed outside through the intake louvers to flush the line with air. The jumpers are then connected and oil circulates through the lines.

Summary of Safety Evaluation: The installation does not affect the operation of the fuel oil transfer system. The fuel oil transfer system is designed to meet seismic Class 1 requirements. The design and installation of the temporary supports maintains the system Class 1 requirements. The lines flushed are not connected to existing plant systems during the flushing. Precautions assure that temporary flange

and hose connections are secured during air and oil flushes to prevent equipment damage or fluid leakage. Barriers are erected to restrict personnel access during flushing activities. Air steams are directed away from permanent plant equipment.

During piping installation the system is not completely seismically supported during the time it takes to install the U-bolt on the temporary support. (SER 93-025-12)

5. TM 94-019, (Common), Water Treatment. TM 94-19 provides a temporary sulfuric acid storage tank for use in the water treatment acid feed system while the existing T39 sulfuric acid storage tank is out of service. A tank truck serves as a temporary tank, and is positioned outside the north wall of the T39 acid tank cubicle. During installation, the temporary tank is connected to an acid discharge/supply line that enables the contents of T39 to be transferred to the temporary tank and subsequently supplied to the acid feed system for use in cation demineralizer bed regeneration. Service air from connection SA-99 in the heating boiler room is used in off-loading the acid from the temporary tank when needed. A pressure regulator is placed on the hose running from SA-99 to the temporary tank to maintain pressure <25 psig.

Summary of Safety Evaluation: The temporary sulfuric acid storage tank is equivalent in function to the existing T39 sulfuric acid storage tank. The primary difference between the two tanks is their location. Since the existing sulfuric acid storage tank is not an initiator of a design basis accident, and since the probability of acid leakage from the temporary tank contacting the main step-up transformers and causing a short is low, the temporary sulfuric acid storage tank does not increase the probability of a previously evaluated accident.

The response to NUREG-0737 Item III.D.3.4 states that because of its low volatility and distant location in the plant the sulfuric acid storage facility is not of concern for control room habitability. Since the temporary acid storage tank is positioned even further from the control room it does not violate this statement. The temporary acid storage tank does not degrade control room habitability via the control room air intakes because sulfuric acid fumes escaping from the temporary tank will sufficiently dissipate before reaching the control room air intakes. The temporary tank has less of a potential to degrade control room habitability than the existing acid storage tank because the existing tank vents to atmosphere so escaping fumes travel into the turbine hall and could enter the control room. Also, a spill in the acid tank cubicle flows to the neutralizing tank, which vents through two vents to the top of the heating boiler room, which is closer to the control room than the temporary tank. In contrast, a spill from the temporary tank stays on the pavement, where it could be cleaned up per AOP-12A. (SER 94-030)

6. TM 94-028, (Common), Water Treatment System. TM 94-028 provides a temporary sulfuric acid storage tank in place of T39 sulfuric acid tank during the neutralization, inspection, and repair of T39. A spill containment dike is constructed around the temporary tank. At times, the temporary tank is connected to the T39 acid tank pumpout connection to enable the contents of T39 to be transferred to the temporary rank and subsequently supplied to the acid feed system for use in cation demineralizer bed regeneration.

Summary of Safety Evaluation: The temporary acid tank is pressurized to ≈ 10 psig using compressed nitrogen to achieve desired acid flow rate during the cation demineralizer bed regeneration process. After the T39 acid tank work is complete, acid remaining in the temporary tank is transferred to T39.

The temporary sulfuric acid storage tank is equivalent in function to the existing T39 sulfuric acid storage tank. The primary difference between the two tanks is their location. Since the existing sulfuric acid storage tank is not an initiator of a design basis accident, and since the probability of acid leakage from the temporary tank contacting the main step-up transformers and causing a short is low, the temporary sulfuric acid storage tank does not increase the probability of a previously evaluated

accident. Additionally, since the existing tank is not associated with any of the accidents evaluated in FSAR Chapter 14, it is not required to mitigate or respond to other design basis events, and does not have a reasonable potential to cause a transient or event which could result in a challenge to safeguards systems. (SER 94-030-01)

7. TM 94-048, (Unit 1), Main Steam System. TM 94-048 adds Furmanite into the gap between the Unit 1 SG handhole cover and the steam generator. Holes are drilled into the sides of the cover plate to provide an injection path into the gap. A wire is wrapped around the handhole cover and peened into the edge of the gap to provide support to the Furmanite while it sets up. Furmanite is injected through ports installed in the holes. After the Furmanite cures, it acts as a temporary gasket.

Summary of Safety Evaluation: The steam generator handhole repair does not increase the probability of occurrence of an accident. Injecting Furmanite into the gasket area stops any leakage in the area thereby reducing the probability of occurrence of an accident. Injecting Furmanite into the gasket area stops leakage in the area and reduces the probability of future steam leaks from the steam generator. A stress calculation shows that the bolts and cover are within allowable stress levels following the Furmanite injection. Injecting Furmanite into the gap between the handhole cover and the steam generator does not increase the consequences of an accident. The handhole is an 8" diameter opening. In the unlikely event that the Furmanite repair caused a complete failure of the handhole, the size of the opening is less than the 16" nozzle considered for the rupture of a steam pipe incident and smaller than the feedwater piping considered in the loss of normal feedwater incident. Therefore, the consequences of a failure are less than previously analyzed. As the stress calculation shows, stress values are within allowable values. Therefore, the probability of a handhole cover failure is not increased.

Furmanite compound is fully compatible with the steam generator materials. Any compound which could enter the downcomer region is broken up and dispersed and removed by normal steam generator blowdown. (SER 94-069)

SPARE PARTS EQUIVALENCY EVALUATION DOCUMENTS (SPEEDs)

1. SPEED 92-032, Part Number Change for Containment Accident Fan Bearings.

Summary of Safety Evaluation: The first bearing change involves a change in part number only. The physical characteristics of the bearing are not changed.

The second change involves using an SKF tapered roller bearing with a steel cage vice the Link Belt tapered roller bearing with a machined bronze cage. The other characteristics of the SKF bearing are the same. The failure modes and failure probability of the two bearings are comparable. The weakest point of this application is the lubricant. Per environmental qualification requirements, the grease is not changed. (SER 94-064)

2. SPEED 93-067, Determination of Reset Level for 27N Degraded Grid Voltage Relays. The SPEED replaces Model 27D degraded voltage relays with Model 27N relays. Unlike the Model 27D relays which have a nominal reset value of 3% above dropout, the Model 27N relays allow for independent adjustment of the reset voltage. It was determined that the reset value should be set at the relay minimum of 0.5% above dropout.

Summary of Safety Evaluation: Degraded bus voltage is not an initiating event for any accident previously analyzed in the FSAR. Tripping of the degraded voltage relays results in the stripping of offsite power followed by the start up and loading of the emergency diesel generators. There is a possibility of unnecessary stripping of offsite power under normal expected operating grid voltages due to the fact that the dropout setpoint for these relays must be set ≈95% of nominal system voltage at the 4160 V safeguards buses to adequately protect safety-related equipment. The stripping of offsite power results in unnecessary challenges to plant safety systems and potentially a unit trip. The time delays associated with these relays allow the relays to reset if adequate voltage is returned to the bus prior to

the completion of the time delay. Lowering the reset value greatly increases the relay's ability to reset and reduces the probability of stripping offsite power due to a short term voltage transient.

The relays assure adequate voltage levels are present at safety-related loads. This is accomplished by setting the appropriate dropout setpoint. Lowering the reset value does not have an effect on the relays ability to assure adequate voltage levels are present at safety-related loads. It does, however, reduce the possibility of stripping offsite power due to a short-term voltage transient. This reduces unnecessary challenges to the safety systems that could reduce wear and tear on safety-related equipment. (SER 90-059-04)

MISCELLANEOUS EVALUATIONS

1. CR 93-418, Service Water Valves SW-LW-61 and SW-LW-62 Do Not Match FSAR Description. Service water AOVs SW-LW-61 and SW-LW-62 receive a non-essential SW isolation signal and can be operated from the blowdown evaporator panel in the primary auxiliary building (PAB). The valves also serve as a seismic boundary. FSAR 9.6.2 states that non-essential service water isolation valves are MOVs capable of remote operation from the control room. FSAR Appendix A states that seismic boundary valves are normally closed or capable of remote operation from the control room. The valve type and control location are not as described in the FSAR. The installed AOVs are capable of performing their safety function and the FSAR is revised to reflect the status of these valves.

   Summary of Safety Evaluation: Service water system operation is not impeded by the use of air operators on SW-LW-61 and 62, or by the location of remote operation for these valves. The system continues to provide cooling to safety-related loads as designated. The SW system cannot initiate accidents as described in FSAR Chapter 14. The control system for SW-LW-61 and 62 is designed to shut these valves if a safety injection (SI) signal is received and less than 4 SW pumps are operating. Use of air operators which cause the valves to fail shut, thereby isolating the non-essential loads, is more reliable than motor operators which fail as-is if control power is lost. The use of air operators and the location of remote operability for these valves does not increase the probability of occurrence of an accident or of a malfunction of equipment important to safety previously evaluated in the FSAR.

   The SW system continues to provide cooling to safety-related loads, allowing safety-related systems to operate as designed, regardless of whether a motor operator or an air operator is used. The use of air operators on SW-LW-61 and 62 increases the probability of these valves performing their design function if the valve control system were to malfunction, since the spring-loaded air operators cause the valves to fail shut. The control circuitry for the SW-LW-61 and 62 solenoids is series in nature, and the solenoids must be energized to open the valves. Failure of the solenoid control switches as a result of a seismic event does not interfere with automatic valve closure. The remote operability location and the use of air operators does not impact the radiation release barriers, create new release mechanisms, or increase the release rate or duration. EOP-0, "Reactor Trip or Safety Injection", directs operators to locally shut SW-LW-61 and 62 if fewer than four service water pumps are running, ensuring proper isolation of non-essential service water loads when required. AOP-9A, "Service Water System Malfunction", describes actions to segment and isolate portions of the SW system following a pipe break.

   Automatic closure operation of SW-LW-61 and 62 is initiated when an SI signal is received and less than 4 SW pumps are operating. For this to occur, the worst single failure has already occurred, specifically the failure of one EDG to start, resulting in only 2 SW pumps operating. The AOVs meet the requirements of MOVs for this application. Use of an air operator is more reliable than a motor operator which fails as-is, and remote operation of SW-LW-61 and 62 from the PAB blowdown evaporator control panel does not create the possibility of an accident or malfunction of equipment important to safety of a different type than previously evaluated in the FSAR.

   Isolation of non-essential SW loads is not discussed in the Basis for any Technical Specification, so remote operation of SW-LW-61 and 62 from the PAB instead of the control room, and use of air

operators, which are more reliable for function than motor operators, on these valves does not reduce the margin of safety as defined in the Basis for any Technical Specification. (SER 94-017)

2. CR 94-011, Safety Evaluation of 345 kV Generator Output Breaker Malfunction.

The General Electric air blast 345 kV generator output breakers experienced a gradual loss of air pressure. It is thought that this problem is due to leakage by a gasket exacerbated by the extreme cold temperatures. The problem with low air to the air blast breakers exists for the generator output breakers.

Summary of Safety Evaluation: There is an interlock in the 345 kV generator output breaker tied to air pressure to prevent it from operating at too low an air pressure. The interlock ensures that the electrical arc can be extinguished and that the breaker is not destroyed. The potential impact of the loss of air pressure on the air blast 345 kV circuit breakers is the failure of the breakers to open on demand.

If the air pressure drops low enough to disable the breaker from operating, it has no impact on the probability of initiating an accident or transient because the breaker remains closed. If the unit trips, stuck breaker protection is provided to isolate the generator from the grid. All safety-related systems and offsite power remain available.

If a turbine or reactor trip signal is generated (not due to an electrical fault), there is approximately a 1-minute delay until the generator output breaker gets an open signal. At the same time, a fast bus transfer of unit auxiliary buses, A01 and A02, to station auxiliary buses, A03 and A04, takes place; the unit auxiliary transformer, X02, low side breakers open; and excitation is removed from the generator. If the generator output breakers fail to open, a stuck breaker signal is generated after ≈7 cycles, which results in a bus section isolation. This normally results in a loss of offsite power to either unit.

In this scenario, offsite power to the safety-related buses is available through the station auxiliary buses and the fast bus transfer takes place. The plant is designed to cope with a unit trip or previously analyzed accidents in the FSAR without the unit auxiliaries; however, if the fast bus transfer does not take place the auxiliary buses can be manually transferred if offsite power is available.

If a trip signal is generated due to an electrical fault on the generator, step-up transformer, X01, or auxiliary transformer, X02, the generator breaker trip signal and fast bus transfer happens immediately. If the generator breaker does not open immediately, the results are similar to that described above. The difference may be that if an electrical fault occurred and the bus sections between the generator output and offsite power supply are split, the fast bus transfer may not occur due to a phase differential. Again, once the fault is cleared the buses can be manually transferred.

The worst case is a cascading failure of breakers resulting in a loss of offsite power to the safety-related buses. This requires additional failures of bus section breakers. All required safety-related equipment is operable including both EDGs. In addition, G05 combustion turbine is operable. Other breakers at the 13 kV and 4 kV levels are not susceptible to the problems with air pressure. The plant is designed to mitigate the consequences of accidents and transients evaluated in the FSAR without offsite power.

The Technical Specifications detail the requirements for offsite power availability to safety buses and the line requirements for power generation from one or both units. These requirements are not affected by the problem with the generator output breakers.

With the problem applicable to the Unit 2 generator output breakers, there is no nuclear safety impact on the units and the potential problem of the breaker not operating is within the design basis of the plant. There are two sources of offsite power and all required safety-related equipment is operable. (SER 94-006)

3. EOPSTPT G.2, SG Level Just in the Narrow Range (Normal Uncertainties).
EOPSTPT G.3, SG Level Just in the Narrow Range (Adverse Uncertainties).

The Westinghouse Owners Group (WOG) emergency response guidelines (ERGs) recommend the use of narrow range SG level just on-scale with instrument inaccuracies to specify entry to the heat sink status tree. Existing procedures used EOPSTPT G.11, "SG Level Just in the Wide Range Including Margin for Operator Response Time (Normal Uncertainties)," for a SG level of 200" during emergency operating procedure usage.

Summary of Safety Evaluation. Use of the G.11 setpoint was justified on the basis that the SG narrow range meter was not a qualified instrument and the fact that 200" was sufficient level for operator actions to align alternate sources of auxiliary feedwater in accordance with EOPs. However, the narrow range instrument is qualified. Therefore, the WOG ERGs recommendation setpoint values of EOPSTPT G.2 (8% for normal conditions) and EOPSTPT G.3 (28% for adverse conditions) are being used for SG level indication. Use of these setpoint values result in entry into the loss of heat sink procedures earlier; thus allowing operators more time to restore heat sink. (SER 94-067)

4. FSAR Sections 11.1.4 and 11.2.5, FSAR Changes to Allow Releases of Tritium Without Passing through RMS.

FSAR Sections 11.1.4 and 11.2.5 changes allow release of a discrete volume of secondary side liquid wastes containing only tritium directly to the circulating water system after isotopically quantifying the tritium in the liquid to be discharged without continuous monitoring by RMS monitors.

Summary of Safety Evaluation: The intent of the wording on liquid discharges in the FSAR is to prevent exceeding 10 CFR 20 dose and radionuclide concentration limits for the general public. For discharges through a pathway not monitored by an RMS monitor, this is accomplished by the isotopic analysis of a discrete volume of water controlling its discharge to ensure sufficient dilution to avoid exceeding the concentration limits. This method must be used for the discharge of liquid whose only detectable radionuclide is tritium even when discharges are via an RMS release pathway because the liquid RMS monitors do not detect tritium. The discharge is controlled via a discharge permit generated by using the Release Accountability Manual procedure RAM 3.2.

The FSAR change does not negate the need for a discharge permit. Therefore, the change does not compromise public safety because it allows liquids to be discharged only after the quantity of radionuclides released are determined and the quantity of liquid released controlled to ensure that concentrations at the point of discharge do not exceed 10 CFR 20 limits.

The changes allow discharge of condenser hotwells containing detectable levels of tritium directly to the circulating system instead of via the retention pond. The direct hard-piped pathway through circulating water discharge can be accomplished much more quickly and does not require flooding the turbine hall sumps or use of a temporary modification. This safety evaluation is an extension to SER 87-017 for MRs 86-085 and 86-086 that provides controlled flow bypass around condensate overboard valves CS-38 and CS-39 to provide better control for the existing condensate overboard flow path. The change facilitates "feed and bleed" operations in the cleanup of condensate. Liquid releases via this path are to be monitored by sampling of discrete volumes. SER 87-017 concludes the sampling to obtain a discharge permit, in accordance with RETS, was sufficient to permit the "feed and bleed" discharge while at power. However, when the hotwells are isolated after shutdown, SER 87-017 does not allow for the use of this pathway for the discharge of condenser hotwells liquids because the air ejector and blowdown monitors no longer monitor the flow. This evaluation documents changes to the FSAR that do not require the blowdown monitor and air ejectors to be used. (SER 94-053)

5. FSAR Figure 5.2, Containment Isolation Valve Designation Changes for Penetration 32b.

The change redesignates 1&2SI-879A as containment isolation valves (CIVs) for Penetration 32b. The CIV designation is removed from 1&2SI-883 and 1&2SI-884, both of which serve as CIVs for

Penetration 32b. The normal position for valve SI-879A is changed from open to locked shut. Normal positions for valves SI-883 and SI-884 remain unchanged.

Summary of Safety Evaluation: Valve SI-879A is included in appropriate Type C local leak rate test procedures as required under 10 CFR 50, Appendix J, for containment isolation valves (CIVs). Local leak rate testing for valves SI-883 and SI-884 are discontinued, consistent with the removal of the CIV designation.

SI-879A is fully qualified to serve as a CIV (Seismic Class 1, ASME Class 2, QA, safety-related, and missile protected). Since 3/4" SI test line return line for Penetration 32b is isolated under normal at-power conditions and is not used by procedure, changing the normal position of SI-879A from open to locked shut has no effect on the operation of the plant. Following the change, Penetration 32b retains two barriers to fission product release, each of which is still a normally locked shut manual valve and qualified to serve as a CIV in all respects.

Moving the CIV designation from outside valves SI-883 and SI-884 to valve SI-879A in-containment is consistent with applicable General Design Criteria referenced in NUREG-0800, and is more consistent with industry standards such as ANS-56.2/ANSI N271-1976, "Containment Provisions for Fluid Systems." The changes do not result in physical changes to plant systems, structures or components. (SER 89-073-05)

6. Manual Relocation of Fuel Assembly V-74 Located in E-2. Fuel assembly V-74 is manually relocated using the polar crane by using hooks suspended by ropes from the crane to engage the springs on the top of the fuel assembly. The assembly is then lifted out of location E-2 and placed in location B-10 or as directed by the core loading supervisor to remain within the temporary storage locations identified in RP-1C, U2R20, "Refueling". The relocation facilitates a correction of a tilted fuel assembly.

Summary of Safety Evaluation: The applicable accident evaluated in the FSAR is a fuel handling accident involving a dropped fuel assembly. If the assembly is not secured on the pins, the manipulator is used to move the assembly. In this case, using hooks suspended by the polar crane is a safer course of action to relocate and secure the assembly than by using the fuel manipulator. The hooks, suspended by nylon rope, are engaged securely into the top springs of the fuel assembly providing assurance of a positive engagement when moving the assembly. The manipulator may not be able to ensure a positive engagement of the assembly and provide too much force on the assembly when attempting to engage it.

The rope is load tested to ensure capability of lifting the fuel assembly. Underwater TV cameras are used to ensure positive engagement of the hooks and to gauge the appropriate height to lift the assembly, relative to adjacent assemblies, in preparation for movement. The assembly is only lifted ≈1'. The polar crane has adequate controls to ensure positive control of the fuel assembly during movement. These controls include fine speed control during lifting motion. Although the polar crane does not have an interlock with a load cell to stop movement, a load cell is used and monitored. If required, manual actions can be taken to stop lifting motion, the assembly is then relocated to a temporary location within the requirements of RP-1C, U2R20. In addition, when the assembly is lifted and moved, personnel are stationed at the polar crane power disconnect switch to disconnect power from the crane should an uncontrolled lifting of the assembly occur. Based on these precautions, the probability of an occurrence of a fuel accident is not increased.

The consequences of a fuel handling accident is not increased. The accident analysis assumptions for a dropped fuel assembly are not affected by this evolution. A backup is stationed to disconnect the power from the polar crane should this be necessary to prevent the possibility of the assembly being raised out of the water. AOP-8B, "Fuel Handling Accident in Containment," addresses actions to respond to this situation. Thus, the consequences of an accident previously evaluated in the FSAR are not increased. Other precautions include limiting personnel in containment to those directly involved with the move. (SER 94-058)

7. Storage of Low-Level Radioactive Waste in the Steam Generator Storage Facility South Bay. Storage of low-level radioactive waste in the south bay of the steam generator storage facility (SGSF) was evaluated when access to a licensed disposal facility is no longer available after June 30, 1994. The storage of low-level radioactive waste is on an interim basis in accordance with Generic Letter 81-038, "Storage of Low-Level Radioactive Wastes at Power Reactor Sites." The facility is used for the storage of low-level radioactive wastes only. Processing of wastes as described in SERs 89-088 and 89-088-01 will not be performed. The wastes to be stored consist of paper, plastic, wood, trash, asbestos, solidified or dewatered liners of primary resin, filter media, solidified or dewatered concentrates, and other miscellaneous items. These wastes are considered "dry" wastes. No wet, corrosive, or radioactive materials that could experience exothermic chemical reactions are stored in the facility.

Summary of Safety Evaluation: Storage of this waste in the south bay of the SGSF does not create the possibility of an accident of a different type than any previously evaluated in the FSAR. The radiological impact of low-level radioactive waste storage in the SGSF south bay is within applicable regulatory limits.

FSAR Section 11.1 is changed to reflect the new waste processing and storage methods employed once interim storage starts. Page 11.1-10, describes the new processing methods for dry activated waste (DAW). Page 11.1-16 described the operation of a DAW baler which is no longer used. Page 11.1-17 reflects present average and annual waste volume. (SER 89-088-02)

8. Unit 1 Cycle 22 Fuel Reload. The U1C22 reload contains 12 fresh Region 24A upgraded optimized fuel assemblies OFA at 4.0 w/o, 16 fresh Region 24B upgraded OFA at 4.4 w/o, 12 Region 23A upgraded OFA, 16 fresh Region 23B upgraded OFA, 12 Region 22A upgraded OFA, 16 Region 22B upgraded OFA, 12 Region 21A upgraded OFA, 16 Region 21B upgraded OFA, 4 Region 20A upgraded OFA, 4 Region 20B upgraded OFA, and 1 Region 13 OFA. The U1C22 core is the sixth reload containing a full region of upgraded OFA fuel for Unit 1. Upgraded OFA fuel is the subject of TS Change Request 127, which was approved by the NRC.

Summary of Safety Evaluation: The reload core involves a potential change to the facility or its operation as described in the FSAR. The U1C22 evaluation concluded the design does not cause safety limits to be exceeded, provided the following conditions are met:

- Cycle 21 burnup is bounded by 11,000 and 11,500 MWD/MTU. Actual Cycle 21 burnup was 11,423 MWD/MTU.

- Cycle 22 burnup is limited to the end-of-full-power-capacity (EOFPC), which is defined as the burnup of fuel when control rods are fully withdrawn, and $\leq$10 ppm boric acid at the Cycle 22 rated power condition of 1518.5 MWt, plus 1500 MWD/MTU power coastdown operation.

- There is adherence to the plant operating limitations given in the Technical Specifications.

Regions 24A and 24B fuel assemblies are Westinghouse upgraded OFA, and have the same mechanical design as the previous Region 23 upgraded OFAs except that the 24A and 24B assemblies incorporate the following three fuel design improvements:

- Fuel assemblies are manufactured with a standard gap of 0.465" between the top of the bottom nozzle and the bottom of the fuel rod end plug. The gap is consistent with the design requirements of the extended burnup bottom grid design. The core neutronic models are unaffected by this repositioning and there is no safety impact on calculated core parameters.

- The bottom nozzle guide thimble and flow hole pitch was adjusted about one mil to ensure proper fit-up of the grid inserts and cold alignment of the thimble tubes and thimble screws. Thermal-hydraulic performance of the bottom nozzle is unchanged.

- A pre-oxidized protective coating on the lower 7" of the fuel rod cladding is applied to guard against debris-induced damage at the bottom grid location. The oxide coating is indistinguishable from in-reactor oxidation. Fuel rod performance and core safety considerations are not adversely affected.

The integral fuel burnable absorber (IFBA) and axial blankets described in WCAP-11872 are incorporated in U1C22. Axial blankets and IFBAs are incorporated in Region 24A. Axial blankets are incorporated in Region 24B.

Design analysis performed for U1C22 assumes a nominal control rod parking elevation (ARO) of 225 steps withdrawn.

The evaluation for fuel assembly reconstitution assesses the safety significance of fuel rod reconstitution and assures that a reconstituted assembly with a stainless steel filler rod meets the design criteria for the existing fuel design. The FSAR Chapter 14 design basis accident analyses affected by the use of upgraded OFA fuel and increased peaking factors are covered in WCAP-11872, except for boron dilution at cold shutdown. The U1C22 kinetics parameter values are bounded by the limit value used in the WCAP-11872 analyses. Core peaking factors for the dropped RCCA event, the rod ejection incident, and the steam line break incident are within the bounds of the analysis limits.

The non-LOCA transient evaluations and analyses show that applicable safety criteria as presented in the FSAR are satisfied. Calculation N-94-029, "Cooldown Recriticality Evaluation U1C22," verifies the validity of Calculation N-89-042, "Evaluation of Containment Pressure Response to a Steam Line Break Based on the Results of Westinghouse Analyses for a Reference 2 Loop PWR," for U1C22 operation.

The large-break LOCA analysis described in the FSAR, shows a peak cladding temperature (PCT) of 2028°F. The small-break LOCA analysis presented in FSAR Section 14.3.1 shows a PCT of 809°F. Subsequent evaluations of the large-break LOCA PCT of 1952°F. Subsequent evaluations of the small-break LOCA analysis have required the addition of 33°F of penalties. This results in an evaluated small-break LOCA PCT of 842°F. Therefore, the PCT limit of 2200°F, as presented in FSAR Section 14.3.1, is met for both the large- and small-break LOCA. The analyses assume an equivalent steam generator tube plugging level limit of 25%. The equivalent tube plugging levels for Unit 1 are <1% for each steam generator. Westinghouse has permanently allocated 5% of the tube plugging margin to offset potential steam generator tube collapse due to postulated seismic and LOCA loads.

The boron dilution at cold shutdown incident with reduced effective RCS volume was evaluated. Calculation N-94-028 shows that ≈15.5 minutes are available from the time dilution starts until the loss of shutdown margin occurs. The acceptance criterion is that minimum operator action time is ≥15 minutes. Therefore, the conclusions of the FSAR for the boron dilution at cold shutdown analysis remain valid.

The evaluation is performed using the Technical Specifications inclusive of Amendment No. 140. (SER 94-027).

9. Unit 2 Cycle 21 Fuel Reload. The U2C21 core contains 121 upgraded optimized fuel assemblies (OFA). Four water displacer assemblies, nine assemblies with integral fuel burnable absorber (IFBA) and twelve peripheral power suppression assemblies (PPSA) are also included in the core.

Summary of Safety Evaluation: The reload core involves a potential change to the facility or its operation as described in the FSAR. The U2C21 evaluation concluded that the design does not cause safety limits to be exceeded, provided the following conditions are met:

- Cycle 20 burnup is bounded by 10,800 and 11,310 MWD/MTU. Actual Cycle 20 burnup was 11,307 MWD/MTU. Letter 94WE*-G-0054, dated October 5, 1994, extends the burnup window reported in the reload safety evaluation from 11,300 MWD/MTU to 11,310

MWD/MTU.

- Cycle 21 burnup is limited to the end-of-full-power-capability (EOFPC), which is defined as the burnup of fuel when all control rods are fully withdrawn, and ≤10 ppm boric acid at the Cycle 21 rated power condition of 1518.5 MWt, plus 1500 MWD/MTU power coastdown operation.

- There is adherence to the plant operating limitations listed in the Technical Specifications.

Operation of the U2C21 core does not involve an increase in the probability or consequences of accidents previously considered, does not involve a decrease in safety margin, and does not involve a significant hazard consideration. Therefore, provided that startup physics testing does not result in any discrepancies with the analysis assumptions, the operation of U2C21 in accordance with Technical Specifications is acceptable based on the reload design and this safety evaluation.

Regions 23A, 23B, 23C and 23D fuel assemblies are Westinghouse upgraded OFA, and have the same mechanical design as the previous Region 22 upgraded OFAs except that Region 23A, 23B, 23C and 23D assemblies incorporate the following fuel design improvements:

- The bottom nozzle guide thimble and flow hole pitch has been adjusted by about 1 mil to ensure proper fit-up of the grid inserts and cold alignment of the thimble tubes and thimble screws. Thermal-hydraulic performance of the bottom nozzle is not changed.

- A pre-oxidized protective coating on the lower 7" of the fuel rod cladding is applied to guard against debris-induced damage at the bottom grid location. The oxide coating is indistinguishable from in-reactor oxidation. Fuel rod performance and core safety considerations are not adversely affected.

The upgraded OFAs and core components are designed to be handled by existing tools. The rod cluster control assemblies (RCCAs), integral fuel burnable absorbers (IFBAs), peripheral power suppression assemblies (PPSAs), and water displacer assemblies are all compatible with the upgraded OFA fuel. Thimble plugs, other than those associated with the water displacer assemblies, are not used in the U2C21 core.

The integral fuel burnable absorber (IFBA) and axial blankets described in WCAP-11872 are incorporated into U2C21. IFBAs are incorporated in Regions 23A and 23B. Axial blankets are incorporated in Regions 23A, 23B, 23C and 23D.

Two new IFBA loading patterns are used in U2C21. The first IFBA loading pattern uses a 132" IFBA stack height (non-standard pattern) in 32 IFBA rods that are loaded symmetrically within the assembly. The second IFBA loading pattern uses a 132" IFBA stack height (non-standard pattern) in 16 IFBA rods that are loaded non-symmetrically within the assembly. The total length of the IFBA increased from 96" to 132," centered axially.

FSAR Chapter 14 design basis accident analyses affected by the use of upgraded OFA fuel and increased peaking factors are covered in WCAP-11872, except for boron dilution at cold shutdown. The U2C21 kinetics parameter values are bounded by the limit value used in the WCAP-11872 analyses. Core peaking factors for the dropped RCCA event, the rod ejection incident, and the steam line break incident are within the bounds of the analysis limits.

The large-break LOCA analysis described in the FSAR shows a peak cladding temperature (PCT) of 2028°F. The small `reak LOCA analysis presented in FSAR Section 14.3.1 shows a PCT of 809°F. Subsequent evaluations of the large-break LOCA analysis have reduced the PCT by 76°F. This results in an evaluated large-break LOCA PCT of 1952°F. Subsequent evaluations of the small-break LOCA analysis have required the addition of 33°F of penalties. This results in an evaluated small-break LOCA PCT of 842°F. Therefore, the PCT limit of 2200°F, as presented in FSAR Section 14.3.1, is

met for both the large- and small-break LOCA. The large-and small-break LOCA analyses assume an equivalent steam generator tube plugging level limit of 25%. The equivalent tube plugging levels for Unit 2 are expected to be ≤19% for each steam generator. Westinghouse has permanently allocated 5% of the tube plugging margin to offset potential steam generator tube collapse due to postulated seismic and LOCA loads.

The boron dilution at cold shutdown incident with reduced effective RCS volume was evaluated. Calculation N-94-133 shows that approximately 15.6 minutes are available from the time dilution starts until the loss of shutdown margin occurs. The acceptance criterion is that minimum operator action time is ≥15 minutes. Therefore, the conclusions of the FSAR for the boron dilution at cold shutdown analysis remain valid.

Asymmetric RCCA withdrawal was analyzed in WCAP-13803, Revision 1, "Generic Assessment of Asymmetric Rod Cluster Control Assembly Withdrawal," August 1993. The analysis is in response to NRC Generic Letter 93-04, "Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies, 10 CFR 50.54 (f)," issued June 21, 1993. The analysis shows that the DNB design basis is satisfied for the most limiting asymmetric RCCA withdrawal case at Point Beach. MR 93-050 changes the CRDM timing sequence to eliminate the possibility for asymmetric RCCA withdrawal during U2R19. (SER 94-057)

10. Unit 2 Cycle 21 Fuel Reload. Supplements to the RSE include a revised Cycle 20 burnup window in letter 94WE*-G-0054, dated October 5, 1994, omission of four thimble plugging rodlets from one water displacer assembly in 94WE*-G-0055, dated October 13, 1994, and a reduction of the minimum measured flow rate in WEP-94-817, dated October 21, 1994.

Summary of Safety Evaluation: As a result of the Cycle 21 evaluation, it is concluded that the Cycle 21 design does not cause safety limits to be exceeded, providing that the following conditions are met:

- Cycle 20 burnup is bounded by 10,800 and 11,310 MWD/MTU. Actual Cycle 20 burnup was 11,307 MWD/MTU. Letter 94WE*-G-0054, dated October 5, 1994, extends the burnup window from 11,300 MWD/MTU, as reported in the Reload Safety Evaluation, to 11,310 MWD/MTU.

- Cycle 21 burnup is limited to the end-of-full-power-capability (EOFPC), which is defined as the burnup of fuel when all control rods are fully withdrawn, and less than or equal to 10 ppm of boric acid at the Cycle 21 rated power condition of 1518.5 MWt, plus 1500 MWD/MTU power coastdown operation.

- There is adherence to the plant operating limitations given in the Technical Specifications.

- Technical Specification Change Request 177 is approved.

The non-LOCA transient evaluations and analyses show that applicable safety criteria, as presented in the FSAR are satisfied. For the U2C21 core, the minimum measured flow rate was reduced by 5200 gpm, to 174,000 gpm as documented in Technical Specification Change Request 177. Westinghouse and WE reviewed all the licensing basis accidents which potentially could be affected by the reload core design and the flow reduction. An evaluation shows the acceptability of revised operating parameters on the LOCA, non-LOCA, steam generator tube rupture, containment integrity and component fatigue analyses. The evaluation is documented in letter WEP-94-817, dated October 21, 1994, "Evaluation of Revised Operating Conditions." The evaluations were performed using methodology, models and procedures which the NRC staff has reviewed and approved. NRC acceptance of reanalyses for the minimum measured flow rate reduction is their anticipated approval of TS Change Request 177.

Steam generator "A" has a higher tube plugging percentage (18.4%) than "B" (15.6%). The asymmetry of the tube plugging about the average (17%) is assessed and the accident analyses remains valid as documented in WEP-94-817, dated October 21, 1994.

A problem with the calibrated range of the resistance temperature detectors was identified. The previously calibrated range of 540°F to 615°F was too narrow to provide adequate reactor protection for some postulated accidents (Reference CRs 94-495 and 94-532). The required range, according to analysis, is 530°F to 635°F. Testing has demonstrated that the existing temperature instrumentation is valid and operable over the extended range with no change in instrument accuracy or uncertainty. The instruments have been calibrated over the extended range.

The large-break LOCA analysis described in the FSAR shows a peak cladding temperature (PCT) of 2028°F. The small-break LOCA analysis presented in FSAR Section 14.3.1 shows a PCT of 809°F. Previously documented evaluations of the large-break LOCA analysis have reduced the PCT by 76°F. TS Change Request 177 increases the PCT by 10°F as a penalty to offset potential steam generator tube collapse due to postulated seismic and LOCA loads. The 10°F PCT penalty replaces a 5% steam generator tube plugging penalty that had been applied to offset the tube/seismic effects. This results in an evaluated large-break LOCA PCT of 1962°F. Subsequent evaluations of the small-break LOCA analysis have required the addition of 33°F of penalties. This results in an evaluated small-break LOCA PCT of 842°F. Therefore, the PCT limit of 2200°F, as presented in FSAR Section 14.3.1, is met for both the large-and small-break LOCA. The analyses assume an equivalent steam generator tube plugging level limit of 25%. The equivalent tube plugging levels for U2C21 are 18.4% for the "A" steam generator and 15.6% for "B". TS Change Request was approved on October 28, 1994. (SER 94-057-01)

NUMBER OF PERSONNEL AND PERSON-REM BY WORK GROUP AND JOB FUNCTION - 1994

Job Group Station Employees	Number of Personnel Greater Than 100 mrem	Total rem for Job Group	Work Function and Total Person-rem					
			Reactor Operations & Surveillance	Routine Maintenance	Inspections	Special Maintenance	Waste Processing	Refueling
Operations	61	16.850	10.070	-------	5.100	-------	0.180	1.500
Maintenance	45	36.020	-------	18.130	0.620	-------	-------	17.270
Chemistry & Health Physics	29	15.660	14.430	-------	-------	-------	1.230	-------
Instrumentation & Control	16	3.080	-------	2.010	0.090	-------	-------	0.980
Administration & Engineering, Regulatory Services	11	3.350	1.600	-------	1.750	-------	-------	-------
Utility Employees	35	20.680	3.010	16.350	1.320	-------	-------	-------
Contractor Workers & Others	170	74.627	0.350	-------	12.330	60.727	1.220	-------
GRAND TOTALS	367	170.267	29.460	36.490	21.210	60.727	2.630	19.750

1294 individuals were monitored exempt from the provisions of 10 CFR 20.

Note: Some data is based upon self-reading dosimeter.

VI. STEAM GENERATOR EDDY CURRENT TESTING

UNIT 1

Inspection Plan: Eddy current testing was not performed during the Unit 1 Refueling 21 outage.

UNIT 2

Inspection Plan: During the Unit 2 Refueling 20 outage, eddy current testing was performed October 5, 1994, to October 12, 1994. Full length eddy current testing was performed on 100% of the unsleeved tubes in each steam generator. In addition, 20% of the sleeved tubes were inspected and 20% of the cold leg unsleeved tubes not included in any inspection plan were inspected to the first support plate. The extent tested in each steam generator is as follows:

Eddy Current Inspection Plan		
Extent of Inspection	Number of Tubes	
	"A" SG Hot/(Cold)	"B" SG Hot/(Cold)
Full Length	1395	1530
No. 1 TSP	(226)	(115)
SLEEVES	1498 (304)*	1396 (281)*
RPC	46	45
Totals	2939 (530)	2971 (396)

* - includes 22 cold leg sleeves in the "A" steam generator and 130 cold leg sleeves in the "B" and the free span of the tube in the cold leg over to the hot leg sleeve.

NOTE: As a result of the preliminary results from the 20% sleeve inspection a decision was made to expand to 100% of the hot leg sleeves based on a Technical Specification C-3 categorization. There was no need to expand on the cold leg sleeve program.

Inspection Results: The results of these inspections revealed 204 tubes in the "A" steam generator with reportable indications, and 173 in the "B" steam generator. The following is a summary of the eddy current inspection results listing the largest reportable indication per tube:

Eddy Current Inspection Results Hot Leg (Cold Leg)		
	"A" SG	"B" SG
DI	0 (0)	6 (0)
DRI	7 (0)	1 (0)
20-29%	10 (20)	23 (28)
30-39%	4 (6)	15 (34)

40-49%	1 (0)	1 (0)
≥50%	4 (0)	2 (0)
NQI	1 (0)	4 (0)
Axial Ind	10 (0)	12 (0)
Sleeve Ind	155 (0)	66 (0)
Totals	192 (26)	130 (62)

% - Percent Through Wall Indication
MBM - Manufacturing Burnishing Marks
MMB - Multiple MBMs
DI - Distorted Indications
MAI - Multiple Axial Indication
SAI - Single Axial Indications
NQI - Non-Quantifiable Indications
*LPI - Upper Sleeve Lower Joint Indication
*UPI - Upper Sleeve Upper Joint Indication

1c - # Tube Support Cold Leg
1h - # Tube Support Hot Leg
FL - Full Length
TEC/H - Tube End C/H Leg
STC/H - Sleeve Top C/H Leg
TSC/H - Tubesheet C/H Leg
DRI - Distorted Roll Ind

* - For LPI and UPI indications the designations of TSH refers to the Top of the Sleeve in the Hot Leg.

"A" Steam Generator Indications

1-6H or C - Tube Support Plate No. Hot or Cold Leg
BPH or C - Baffle Plate Hot or Cold Leg
MBM - Manufacturing Burnishing Marks
NQN - Non-Quantifiable Indication - Not Reportable
TSH or C - Tube Sheet Hot or Cold Leg

DNG - Ding
AV1-4 - Anti-Vib Bar No
MMB - Multiple MBMs

NOTE: All inch marks are above the referenced location unless otherwise specified.

Row - Column	Indication	Location	Inch Mark
6-39	LPI	TSH	0.2
6-40	LPI	TSH	0.5
6-42	LPI	TSH	0.3
6-46	UPI	TSH	2.9
6-54	UPI	TSH	2.3
6-58	LPI	TSH	0.4
6-60	UPI	TSH	3.3
7-31	UPI	TSH	2.8
7-31	LPI	TSH	0.4
7-37	LPI	TSH	0.1

Row - Column	Indication	Location	Inch Mark
7-39	UPI	TSH	2.9
7-43	LPI	TSH	0.2
7-49	LPI	TSH	1.3
7-60	LPI	TSH	0.3
7-78	29	TSH	0.6
8-33	UPI	TSH	2.6
8-47	LPI	TSH	0.5
8-47	UPI	TSH	2.8
8-51	UPI	TSH	2.4
8-54	LPI	TSH	0.1
8-76	LPI	TSH	0.5
9-5	22	1H	0.2
9-32	LPI	TSH	0.5
9-34	LPI	TSH	0.6
9-35	LPI	TSH	0.4
9-38	UPI	TSH	2.4
9-39	UPI	TSH	2.6
9-43	LPI	TSH	0.4
9-47	UPI	TSH	2.7
9-51	UPI	TSH	2.7
9-59	LPI	TSH	0.2
9-63	LPI	TSH	0.4
9-66	UPI	TSH	3.6
10-33	LPI	TSH	0.3
10-37	UPI	TSH	2.6
10-42	LPI	TSH	0.6
10-43	UPI	TSH	2.5
10-43	LPI	TSH	0.4
11-33	LPI	TSH	0.5
11-75	LPI	TSH	0.3
12-39	LPI	TSH	0.5
12-70	LPI	TSH	0.3

Row - Column	Indication	Location	Inch Mark
12-75	LPI	TSH	0.5
13-18	LPI	TSH	0.8
13-22	LPI	TSH	0.4
13-66	LPI	TSH	0.3
13-68	LPI	TSH	0.5
13-69	UPI	TSH	3.5
14-21	LPI	TSH	0.0
14-22	LPI	TSH	0.2
14-28	LPI	TSH	0.3
14-32	LPI	TSH	0.2
14-51	UPI	TSH	2.6
14-56	LPI	TSH	0.0
14-57	LPI	TSH	0.2
14-66	LPI	TSH	0.2
14-67	LPI	TSH	0.1
14-72	LPI	TSH	0.3
14-76	LPI	TSH	0.3
15-27	LPI	TSH	0.4
15-37	LPI	TSH	0.3
15-42	LPI	TSH	0.3
15-56	LPI	TSH	0.2
16-18	LPI	TSH	0.8
16-19	LPI	TSH	0.4
16-21	LPI	TSH	0.0
16-22	LPI	TSH	0.7
16-40	LPI	TSH	0.4
16-45	LPI	TSH	0.2
16-57	UPI	TSH	2.7
16-76	LPI	TSH	0.4
16-87	MAI	TEH	2.4
17-18	LPI	TSH	0.2
17-19	LPI	TSH	0.3

Row - Column	Indication	Location	Inch Mark
17-21	LPI	TSH	0.0
17-39	LPI	TSH	0.3
17-42	LPI	TSH	0.5
17-42	UPI	TSH	2.8
17-47	LPI	TSH	0.3
17-50	LPI	TSH	0.3
17-55	LPI	TSH	0.2
17-63	LPI	TSH	0.3
18-5	36	1H	0.1
18-6	47	1H	0.1
18-32	UPI	TSH	3.3
18-33	LPI	TSH	0.6
18-36	UPI	TSH	2.6
18-70	LPI	TSH	0.5
19-18	LPI	TSH	0.3
19-25	LPI	TSH	0.4
19-37	UPI	TSH	2.5
19-41	UPI	TSH	2.9
19-47	LPI	TSH	0.4
19-52	LPI	TSH	0.4
19-73	UPI	TSH	4.2
20-19	LPI	TSH	0.0
20-21	LPI	TSH	0.4
20-55	UPI	TSH	4.2
20-57	UPI	TSH	3.6
21-66	LPI	TSH	0.6
21-73	LPI	TSH	0.6
22-7	33	2H	0.0
22-7	30	2H	0.1
22-20	LPI	TSH	0.3
22-56	UPI	TSH	1.8
22-67	LPI	TSH	0.3

Row - Column	Indication	Location	Inch Mark
23-21	LPI	TSH	0.2
23-36	LPI	TSH	0.2
23-38	LPI	TSH	0.6
23-65	LPI	TSH	0.2
24-23	LPI	TSH	0.2
24-67	LPI	TSH	0.3
24-68	LPI	TSH	0.3
25-23	LPI	TSH	0.3
25-32	UPI	TSH	2.0
25-57	LPI	TSH	0.0
25-63	LPI	TSH	0.6
25-63	LPI	TSH	0.3
25-67	LPI	TSH	0.3
26-25	LPI	TSH	0.3
26-26	LPI	TSH	0.4
26-56	LPI	TSH	0.3
27-65	LPI	TSH	0.2
28-31	LPI	TSH	0.3
28-34	LPI	TSH	0.0
29-35	LPI	TSH	0.0
29-37	LPI	TSH	0.0
29-42	LPI	TSH	-0.1
29-53	LPI	TSH	0.3
30-43	LPI	TSH	0.0
30-44	LPI	TSH	0.5
30-55	UPI	TSH	4.5
31-37	LPI	TSH	0.4
31-41	LPI	TSH	0.6
31-42	LPI	TSH	0.3
31-45	LPI	TSH	0.2
32-47	UPI	TSH	2.8
32-49	LPI	TSH	0.2

Row - Column	Indication	Location	Inch Mark
33-20	MAI	TEH	2.3
34-57	SAI	TEH	2.4
36-19	MAI	TEH	2.6
36-60	MAI	TEH	2.9
37-70	MAI	TEH	3.0
39-50	27	1H	14.9
40-26	31	TSH	5.8
40-62	86	TEH	7.4
40-62	76	TEH	2.5
40-62	87	TEH	7.4
40-62	MAI	TEH	8.7
40-62	83	TEH	7.9
41-37	MAI	TEH	6.4
42-51	27	TSH	0.4
43-44	20	1H	0.0
43-50	21	1H	0.0
1-91	34	1C	0.0
4-31	21	TSC	1.0
4-34	29	TSC	1.5
5-31	30	TSC	0.5
5-31	23	TSC	1.1
5-64	22	TSC	0.4
5-74	21	TSC	1.7
6-25	23	TSC	0.8
6-33	24	TSC	0.5
6-34	29	TSC	0.5
7-30	23	TSC	0.5
7-34	27	TSC	0.6
7-37	27	TSC	0.9
7-37	36	TSC	0.6
8-24	21	TSC	1.0
8-34	34	TSC	0.5

Row - Column	Indication	Location	Inch Mark
8-36	21	TSC	0.6
8-59	29	TSC	0.4
9-25	23	TSC	0.6
9-58	41	TSC	0.5
11-47	33	TSC	0.7
14-48	26	TSC	0.6
14-48	34	TSC	1.3
17-47	21	TSC	0.6
18-60	22	TSC	11.5
19-30	20	TSC	1.0
40-48	23	TSC	41.8

"B" Steam Generator Indications

1-6H or C - Tube Support Plate No. Hot or Cold Leg
BPH or C - Baffle Plate Hot or Cold Leg
MBM - Manufacturing Burnishing Marks
MMB - Multiple MBMs
NQN - Non-Quantifiable Indication - Not Reportable
TSH or C - Tube Sheet Hot or Cold Leg
DNG - Ding
AV1-4 -Anti-Vib Bar No.

NOTE: All inch marks are above the referenced location unless otherwise specified.

Row - Column	Indication	Location	Inch Mark
3-23	UPI	TSH	2.3
3-28	UPI	TSH	3.4
3-55	UPI	TSH	1.2
3-62	UPI	TSH	2.5
3-63	UPI	TSH	2.3
3-66	UPI	TSH	1.1
3-83	SAI	TEH	0.3
3-84	29	5H	-0.3
4-26	UPI	TSH	2.5
4-27	LPI	TSH	0.3
4-35	LPI	TSH	0.0

Row - Column	Indication	Location	Inch Mark
4-42	LPI	TSH	0.3
4-57	UPI	TSH	2.2
4-66	UPI	TSH	1.3
4-68	UPI	TSH	2.8
5-56	UPI	TSH	2.3
5-63	UPI	TSH	2.6
5-67	UPI	TSH	4.1
5-86	MAI	TEH	3.0
6-35	UPI	TSH	3.7
6-63	UPI	TSH	2.1
6-66	UPI	TSH	4.5
7-15	22	1H	0.1
7-61	UPI	TSH	3.9
8-24	UPI	TSH	2.7
8-71	UPI	TSH	3.0
8-73	UPI	TSH	3.2
8-86	MAI	TEH	3.9
8-91	31	TSH	42.3
8-91	20	TSH	49.9
9-67	UPI	TSH	1.5
9-81	28	1H	19.1
10-18	UPI	TSH	3.4
10-34	UPI	TSH	2.8
10-55	UPI	TSH	2.9
10-71	UPI	TSH	3.5
10-76	32	TSH	0.2
10-86	SAI	TEH	7.8
10-86	SAI	TEH	9.1
11-29	UPI	TSH	3.5
12-23	UPI	TSH	3.2
12-89	20	TSH	3.0
13-64	LPI	TSH	0.7

Row - Çolumn	Indication	Location	Inch Mark
14-23	UPI	TSH	2.4
14-32	UPI	TSH	0.5
14-83	MAI	TEH	3.5
14-86	SAI	TEH	7.7
14-86	MAI	TEH	2.8
14-87	MAI	TEH	6.5
16-24	UPI	TSH	2.7
16-33	UPI	TSH	3.5
16-34	UPI	TSH	3.4
16-38	UPI	TSH	1.2
16-38	LPI	TSH	0.1
16-39	UPI	TSH	3.4
16-44	LPI	TSH	0.2
17-5	24	1H	4.9
17-15	21	TEH	4.5
17-43	LPI	TSH	0.4
18-36	UPI	TSH	3.0
18-37	UPI	TSH	2.7
18-38	UPI	TSH	3.8
18-39	UPI	TSH	3.7
18-41	UPI	TSH	3.5
18-64	LPI	TSH	0.2
18-72	UPI	TSH	3.3
19-22	UPI	TSH	2.5
19-24	UPI	TSH	2.4
20-70	UPI	TSH	3.2
21-6	29	1H	0.9
21-56	UPI	TSH	3.1
22-19	36	TSH	30.8
23-12	SAI	TEH	8.1
23-14	34	TEH	5.8
23-45	LPI	TSH	0.1

Row - Column	Indication	Location	Inch Mark
23-53	LPI	TSH	0.8
24-47	UPI	TSH	3.2
25-16	SAI	TEH	6.2
25-31	UPI	TSH	2.8
25-36	UPI	TSH	2.3
25-47	UPI	TSH	4.7
26-10	32	4H	0.0
26-10	29	3H	0.0
26-16	SAI	TEH	9.9
26-47	UPI	TSH	2.8
26-73	23	1H	18.5
26-75	27	1H	14.2
27-33	UPI	TSH	3.4
27-44	UPI	TSH	2.4
27-79	28	TSH	6.2
27-79	33	TSH	3.7
28-16	32	TSH	46.9
28-16	32	TSH	43.0
28-34	UPI	TSH	2.8
29-43	UPI	TSH	2.4
29-45	LPI	TSH	0.3
30-40	UPI	TSH	2.7
30-53	UPI	TSH	3.2
31-71	26	1H	8.4
32-35	21	1H	18.6
32-44	UPI	TSH	2.7
32-53	20	1H	10.8
32-53	25	TSH	1.3
32-53	35	TSH	1 4
33-48	28	TSH	0.6
33-67	MAI	TEH	7.1
34-39	39	1H	7.7

Row - Column	Indication	Location	Inch Mark
36-48	22	TSH	35.7
36-48	21	TSH	42.5
38-25	30	TSH	50.3
38-33	28	1H	29.0
38-61	32	AV4	0.0
39-31	54	TEH	6.6
39-31	69	TEH	6.1
39-31	SAI	TEH	6.6
41-29	28	TSH	23.6
41-49	20	TSH	39.1
42-41	26	TSH	35.6
42-60	28	TSH	6.1
42-60	32	TSH	0.7
43-58	38	TSH	2.3
43-60	28	TSH	3.0
43-60	36	TSH	2.6
45-47	33	2H	0.0
1-2	33	1C	0.0
2-1	24	TSC	8.9
3-58	24	TSC	0.6
3-59	20	TSC	0.6
3-67	33	TSC	1.7
4-71	33	TSC	0.7
5-2	24	1C	0.0
5-59	35	TSC	0.7
7-76	27	TSC	1.3
11-29	33	TSC	0.8
12-71	27	TSC	1.0
13-71	22	TSC	0.6
16-33	29	TSC	10.1
17-36	23	TSC	0.7
19-37	21	TSC	1.3

Row - Column	Indication	Location	Inch Mark
20-58	20	TSC	0.7
21-7	30	1C	-0.1
21-31	24	TSC	1.2
22-8	23	1C	0.0
22-28	37	1C	0.0
22-86	35	1C	0.0
26-12	21	1C	0.0
26-13	29	1C	0.0
26-65	31	TSC	38.1
26-68	23	TSC	0.8
28-49	30	TSC	2.2
29-28	34	1C	0.0
29-30	24	1C	-0.1
30-47	33	1C	0.1
30-48	35	1C	0.1
30-49	34	1C	0.1
31-28	35	1C	-0.1
31-36	35	1C	0.1
31-67	34	1C	-0.0
32-21	34	1C	-0.1
32-70	37	1C	-0.1
33-36	24	1C	-0.1
33-46	36	1C	-0.1
33-48	34	1C	0.0
33-72	35	1C	-0.1
33-73	38	1C	-0.1
34-23	36	1C	-0.1
34-52	32	1C	0.0
34-53	23	1C	-0.1
34-55	26	1C	-0.1
35-22	34	TSC	12.5
36-21	27	1C	-0.2

Row - Column	Indication	Location	Inch Mark
36-22	20	1C	-0.1
36-25	39	1C	-0.1
37-21	36	1C	-0.1
37-27	25	1C	-0.0
37-62	33	1C	0.0
38-52	30	1C	-0.1
38-54	32	1C	-0.1
38-55	29	1C	-0.1
39-24	25	1C	-0.1
39-25	37	1C	0.0
39-27	31	1C	0.0
39-35	29	1C	-0.0
39-56	27	TSC	41.7
41-48	33	1C	0.1
42-49	28	1C	-0.0

Repaired or Plugged Tubes: Steam generator tube plugging was performed on each steam generator during U2R20 as a result of eddy current indications. There were 167 tubes plugged in the "A" steam generator and 78 tubes plugged in the "B" steam generator. The tubes that were plugged in both steam generators were per the Technical Specification plugging limit of 40% or as a result of industry recognized pluggable indications. The rise in the number of pluggable indications is a direct result of an industry driven requirement to examine the upper sleeve joint parent tube. As a result of the phenomena alone we plugged 155 tubes in the "A" steam generator and 66 in the "B" steam generator.

NOTE: All inch marks are above the referenced location unless otherwise specified.

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
4-6	DRI	TEH	2.0
4-6	MAI	TEH	2.2
18-6	DSI	1H	0.0
18-6	47%	1H	0.1
16-18	LPI	TSH	0.8
17-18	LPI	TSH	0.2
19-18	LPI	TSH	0.3
13-18	LPI	TSH	0.8
36-19	DRI	TEH	2.8
36-19	MAI	TEH	2.6
16-19	LPI	TSH	0.4
17-19	LPI	TSH	0.3
20-19	LPI	TSH	0.0
33-20	DRI	TEH	2.5
33-20	MAI	TEH	2.3
22-20	LPI	TSH	0.3
4-20	LPI	TSH	0.0
17-21	LPI	TSH	0.0
14-21	LPI	TSH	0.0
20-21	LPI	TSH	0.4
23-21	LPI	TSH	0.2
6-21	LPI	TSH	0.4
4-21	LPI	TSH	0.1
16-21	LPI	TSH	0.0

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
16-22	LPI	TSH	0.7
14-22	LPI	TSH	0.2
3-22	LPI	TSH	0.4
13-22	LPI	TSH	0.4
2-23	LPI	TSH	0.3
3-23	LPI	TSH	0.2
25-23	LPI	TSH	0.3
24-23	LPI	TSH	0.2
3-24	LPI	TSH	0.3
4-24	LPI	TSH	0.7
26-25	LPI	TSH	0.3
19-25	LPI	TSH	0.4
4-25	LPI	TSH	0.4
26-26	LPI	TSH	0.4
15-27	LPI	TSH	0.4
5-27	UPI	TSH	2.7
5-27	LPI	TSH	0.3
6-28	LPI	TSH	0.2
14-28	LPI	TSH	0.3
7-31	UPI	TSH	2.8
7-31	LPI	TSH	0.4
28-31	LPI	TSH	0.3
14-32	LPI	TSH	0.2
25-32	UPI	TSH	2.0
18-32	UPI	TSH	3.3
9-32	LPI	TSH	0.5
10-33	LPI	TSH	0.3
8-33	UPI	TSH	2.6
18-33	LPI	TSH	0.6
11-33	LPI	TSH	0.5
28-34	LPI	TSH	0.0

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
5-34	LPI	TSH	0.5
4-34	UPI	TSH	2.6
4-34	29%	TSC	1.5
9-34	LPI	TSH	0.6
4-35	LPI	TSH	0.6
5-35	LPI	TSH	0.3
5-35	16%	TSC	1.3
29-35	LPI	TSH	0.0
9-35	LPI	TSH	0.4
9-35	1%	TSC	0.6
23-36	LPI	TSH	0.2
18-36	UPI	TSH	2.6
15-37	LPI	TSH	0.3
19-37	UPI	TSH	2.5
31-37	LPI	TSH	0.4
41-37	NQI	TEH	6.7
41-37	NQI	TEH	4.9
41-37	MAI	TEH	6.4
7-37	27%	TSC	0.9
7-37	LPI	TSH	0.1
7-37	36%	TSC	0.6
29-37	LPI	TSH	0.0
10-37	UPI	TSH	2.6
9-38	14%	TSC	1.9
9-38	UPI	TSC	2.4
23-38	LPI	TSH	0.6
9-39	UPI	TSH	2.6
6-39	LPI	TSH	0.2
7-39	UPI	TSH	2.9
12-39	LPI	TSH	0.5
17-39	LPI	TSH	0.3

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
16-40	LPI	TSH	0.4
6-40	LPI	TSH	0.5
5-40	UPI	TSH	3.0
31-41	LPI	TSH	0.6
19-41	UPI	TSH	2.9
5-41	UPI	TSH	2.6
31-42	LPI	TSH	0.3
15-42	LPI	TSH	0.3
10-42	LPI	TSH	0.6
17-42	UPI	TSH	2.8
17-42	LPI	TSH	0.5
6-42	LPI	TSH	0.3
29-42	LPI	TSH	-0.1
30-43	LPI	TSH	0.0
10-43	LPI	TSH	0.4
10-43	UPI	TSH	2.5
9-43	LPI	TSH	0.4
7-43	LPI	TSH	0.2
4-43	LPI	TSH	0.3
30-44	LPI	TSH	0.5
16-45	LPI	TSH	0.2
31-45	LPI	TSH	0.2
6-46	UPI	TSH	2.9
4-47	LPI	TSH	0.3
4-47	UPI	TSH	2.5
9-47	UPI	TSH	2.7
19-47	LPI	TSH	0.4
8-47	UPI	TSH	2.8
8-47	LPI	TSH	0.5
17-47	21%	TSC	0.6
17-47	LPI	TSC	0.3

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
32-47	UPI	TSH	2.8
7-49	LPI	TSH	1.3
32-49	LPI	TSH	0.2
17-50	LPI	TSH	0.3
9-51	UPI	TSH	2.7
14-51	UPI	TSH	2.6
8-51	UPI	TSH	2.4
19-52	LPI	TSH	0.4
29-53	LPI	TSH	0.3
8-54	LPI	TSH	0.1
6-54	UPI	TSH	2.3
30-55	UPI	TSH	4.5
20-55	UPI	TSH	4.2
20-55	18%	TSC	19.9
17-55	LPI	TSH	0.2
5-55	LPI	TSH	0.3
22-56	UPI	TSH	1.8
26-56	LPI	TSH	0.3
14-56	LPI	TSH	0.0
15-56	LPI	TSH	0.2
14-57	LPI	TSH	0.2
16-57	UPI	TSH	2.7
34-57	DRI	TEH	2.9
34-57	SAI	TEH	2.4
20-57	UPI	TSH	3.6
25-57	LPI	TSH	0.0
9-58	41%	TSC	0.5
6-58	LPI	TSH	0.4
4-59	UPI	TSH	4.4
9-59	LPI	TSH	0.2
2-59	UPI	TSH	3.2

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
7-60	LPI	TSH	0.3
4-60	UPI	TSH	2.7
6-60	UPI	TSH	3.3
36-60	DRI	TEH	2.6
36-60	MAI	TEH	2.9
3-62	LPI	TSH	0.4
40-62	RST	2H	0.0
40-62	83%	TEH	7.9
40-62	86%	TEH	7.4
40-62	76%	TEH	2.5
40-62	87%	TEH	7.4
40-62	MAI	TEH	8.7
25-63	LPI	TSH	0.6
25-63	LPI	TSH	0.3
17-63	LPI	TSH	0.3
9-63	LPI	TSH	0.4
27-65	LPI	TSH	0.2
23-65	LPI	TSH	0.2
2-65	UPI	TSH	3.0
9-66	UPI	TSH	3.6
14-66	LPI	TSH	0.2
13-66	LPI	TSH	0.3
3-66	UPI	TSH	3.5
21-66	LPI	TSH	0.6
3-67	LPI	TSH	0.0
24-67	LPI	TSH	0.3
14-67	LPI	TSH	0.1
25-67	LPI	TSH	0.3
5-67	LPI	TSH	0.2
5-67	LPI	TSH	0.3
22-67	LPI	TSH	0.3

Plugged Tube in the "A" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
4-68	LPI	TSH	0.0
13-68	LPI	TSH	0.5
24-68	LPI	TSH	0.3
13-69	UPI	TSH	3.5
18-70	LPI	TSH	0.5
37-70	DRI	TEH	2.1
37-70	MAI	TEH	3.0
12-70	LPI	TSH	0.3
14-72	LPI	TSH	0.3
21-73	LPI	TSH	0.6
19-73	UPI	TSH	4.2
12-75	LPI	TSH	0.5
11-75	LPI	TSH	0.3
8-76	LPI	TSH	0.5
16-76	LPI	TSH	0.4
14-76	LPI	TSH	0.3
5-77	74%	TEH	12.4
5-77	80%	TEH	12.1
5-77	SAI	TEH	10.3
16-87	DRI	TEH	2.9
16-87	MAI	TEH	2.4

% - Percent Through Wall
1H or 1C - Support Plate Number Hot or CD Cold Leg
DRI - Distorted Roll Indication
MAI - Multiple Axial Indication
SAI - Single Axial Indication
TEH - Tube End Hot Leg
TSH - Tube Sheet Hot Leg
DTI -Distorted Tubesheet Indication

DI - Distorted Indication
RST - Restricted
NQI - Non-Quantifiable Indication
DIM - Dimension

Plugged Tube in the "B" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
23-12	DI	TEH	8.3
23-12	SAI	TEH	8.1

Plugged Tube in the "B" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
26-16	DI	TEH	9.4
26-16	SAI	TEH	9.9
25-16	DI	TEH	6.4
25-16	SAI	TEH	6.2
10-18	UPI	TSH	3.4
19-22	UPI	TSH	2.5
12-23	UPI	TSH	3.2
14-23	UPI	TSH	2.4
3-23	UPI	TSH	2.3
19-24	UPI	TSH	2.4
8-24	UPI	TSH	2.7
16-24	UPI	TSH	2.7
4-26	UPI	TSH	2.5
4-27	LPI	TSH	0.3
3-28	UPI	TSH	3.4
11-29	33%	TSC	0.8
11-29	UPI	TSH	3.5
25-31	UPI	TSH	2.8
39-31	69%	TEH	6.1
39-31	54%	TEH	6.6
39-31	SAI	TEH	6.6
14-32	UPI	TSH	0.5
16-33	UPI	TSH	3.5
16-33	29%	TSC	10.1
27-33	UPI	TSH	3.4
10-34	UPI	TSH	2.8
16-34	UPI	TSH	3.4
28-34	UPI	TSH	2.8
4-35	LPI	TSH	0.0
6-35	UPI	TSH	3.7
25-36	UPI	TSH	2.3

Plugged Tube in the "B" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
18-36	UPI	TSH	3.0
18-37	UPI	TSH	2.7
18-38	UPI	TSH	3.8
16-38	UPI	TSH	1.2
16-38	LPI	TSH	0.1
18-39	UPI	TSH	3.7
16-39	UPI	TSH	3.4
30-40	UPI	TSH	2.7
18-41	UPI	TSH	3.5
4-42	LPI	TSH	0.3
29-43	UPI	TSH	2.4
17-43	LPI	TSH	0.4
16-44	LPI	TSH	0.2
27-44	UPI	TSH	2.4
32-44	UPI	TSH	2.7
23-45	LPI	TSH	0.1
29-45	LPI	TSH	0.3
24-47	UPI	TSH	3.2
25-47	UPI	TSH	4.7
26-47	UPI	TSH	2.8
23-53	LPI	TSH	0.8
30-53	UPI	TSH	3.2
10-55	UPI	TSH	2.9
3-55	UPI	TSH	1.2
3-55	17%	TSC	0.8
5-56	UPI	TSH	2.3
21-56	UPI	TSH	3.1
4-57	UPI	TSH	2.2
7-61	UPI	TSH	3.9
3-62	UPI	TSH	2.5
6-63	UPI	TSH	2.1

Plugged Tube in the "B" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
5-63	UPI	TSH	2.6
3-63	UPI	TSH	2.3
13-64	LPI	TSH	0.7
18-64	LPI	TSH	0.2
3-66	UPI	TSH	1.1
4-66	UPI	TSH	1.3
6-66	UPI	TSH	4.5
33-67	DI	TEH	12.8
33-67	DI	TEH	5.9
33-67	MAI	TEH	7.1
5-67	UPI	TSH	4.1
9-67	UPI	TSH	1.5
4-68	UPI	TSH	2.8
20-70	UPI	TSH	3.2
8-71	UPI	TSH	3.0
10-71	UPI	TSH	3.5
18-72	UPI	TSH	3.3
8-73	UPI	TSH	3.2
3-83	DRI	TEH	0.5
3-83	SAI	TEH	0.3
14-83	NQI	TEH	4.5
14-83	MAI	TEH	3.5
5-86	DI	TEH	3.6
5-86	MAI	TEH	3.0
10-86	DI	TEH	8.2
10-86	SAI	TEH	7.8
10-86	SAI	TEH	9.1
8-86	NQI	TEH	3.9
8-86	MAI	TEH	3.9
14-86	NQI	TEH	5.7
14-86	SAI	TEH	7.6

Plugged Tube in the "B" Steam Generator			
Row - Column	Indication/ %	Location	Inch Mark
14-86	MAI	TEH	2.8
14-87	NQI	TEH	3.0
14-87	MAI	TEH	6.5

% - Percent Through Wall
1H or 1C - Support Plate Number Hot or Cold Leg
MAI - Multiple Axial Indication
SAI - Single Axial Indication
TEH - Tube End Hot Leg
DTI -Distorted Tubesheet Indication
NQI -Non-Quantifiable Indication

TSH - Tube Sheet Hot Leg
RST - Restricted
DI - Distorted Indication
DIM - Dimension

VII. REACTOR COOLANT SYSTEM RELIEF VALVE CHALLENGES

Overpressure Protection During Normal Pressure and Temperature Operation

There were no challenges to the Unit 1 or Unit 2 reactor coolant system power-operated relief valve or safety valves at normal operating pressure and temperature in 1994.

Overpressure Protection During Low Pressure and Temperature Operation

There were no challenges to Unit 1 or Unit 2 power-operated relief valves during low temperature and low pressure operation in 1994.

VIII. REACTOR COOLANT ACTIVITY ANALYSIS

There were no indications during operation of Unit 1 or Unit 2 in 1994 where reactor coolant activity exceeded that allowed by Technical Specifications.