SMUD
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AN ELECTRIC SYSTEM SERVING THE HEART OF CALIFORNIA

RJR 85-531

October 25, 1985

DIRECTOR OF NUCLEAR REACTOR REGULATION
ATTN HUGH L THOMPSON JR
DIVISION OF LICENSING
U S NUCLEAR REGULATORY COMMISSION
WASHINGTON D C 20555

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SUMMARY AND SUPPLEMENTAL INFORMATION FROM TRANSIENT OF OCTOBER 2, 1985

References: R. J. Rodriguez to H. L. Thompson 10/14/85 (RJR 85-514)
R. J. Rodriguez to H. L. Thompson 10/18/85 (RJR 85-520)

During an NRC/SMUD meeting on October 23, 1985 concerning the Rancho Seco Auxiliary Feedwater system (AFW), the District assented to supply the NRC with additional and summary information on the October 2, 1985 transient, and a description of the District's actions concerning plans to upgrade the AFW system.

The references described certain items the District is pursuing and will continue to pursue as a result of its systematic program to resolve concerns from the October 2, 1985 transient. The items in the District's plan include both pre and post startup actions to determine root cause of the October 2, 1985 event, and to institute corrective programs to significantly reduce the likelihood of similar reoccurrences.

On October 25, 1985, the District in a teleconference call with various NRC staff, including Region V, NRR and I&E, agreed to submit information on 11 items of interest. These items are attachments to this letter.

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The following briefly describes the 11 items the District is submitting:

(1) Main Feedwater Pump Trips - Analysis and Findings

After an intensive investigation, the District has determined the probable cause of the MFP trips. The District used not only key District personnel, but also the resources of INPO, Arkansas Power and Light and vendor representatives. The team concluded:

- The A-MFP trip was caused by a defective High Discharge Pressure Switch.
- The most probable cause of the B-MFP trip was an operator manual trip.
- The MPFs, their controls and operator training, are adequate to support power operation.
- The addition of trip monitoring circuitry to the MFPs will significantly enhance future efforts to investigate MFP trips.

(2) HPI "A" Flow Anomaly:

As a result of analysis, testing and surveillance, the District has traced the HPI "A" flow anomaly to a characteristic of the Rosemount transmitters used to provide HPI flow indication.

As part of the investigation, the District confirmed through special functional flow testing that flow was always available as designed in the HPI "A" line. Radiography, in conjunction with the functional tests of the HPI "A" control valve, verified that the source of the anomaly was instrumentation and not mechanical.

(3) Heat Balance for Cooldown of 10/2/85 Transient

The District performed a quasi steady state energy balance that showed good agreement between RCS heat removal and the observed cooldown. The analysis used heat removed from the OTSG's, based on AFW flow, OTSG level and assumed steam loads.

(4) Evaluation of the Reactor Vessel Cooldown

The RCS cooldown caused by the transient of October 2, 1984 was within the analytical limits meeting the requirements of 10 CFR 50 Appendix G.

(5) Auxiliary Feedwater Control Logic Modification

The District is modifying, prior to startup, the AFW valve control logic. The initiation of ICS controlled AFW valves will be off of Main Feedwater Pump discharge pressure. This is the same parameter that initiates the start of AFW pumps. This change has been made to ensure AFW flow into the steam generators should the need arise. We have not identified any failure that would cause both a loss of main feedwater and prevent AFW from being available to cool the steam generators. This applies to the specific concern of a failure closing all four main feedwater valves and preventing the ability to supply AFW.

(6) Auxiliary Feedwater Pump Surveillance Testing

The District has scheduled the Rancho Seco Auxiliary Feedwater Pump Surveillance from a quarterly to a monthly test period. During testing, an operator is stationed at and observes the test valve. Additionally, the District will submit a Technical Specification Change Request within 60 days to reflect this increased testing frequency.

(7) Review of Operating Procedures

The District has reviewed the Emergency Operating Procedures (EOP) in light of the October 2, 1985 event. The review has determined that the EOP's are appropriate and correct. The District will incorporate, prior to startup, an enhancement to the excessive heat transfer procedure (main steam line break, overfeed). Feedwater pumps will be tripped to terminate overcooling should closure of FW valves fail to terminate excessive FW regardless of OTSG level.

(8) Oil Levels on Safety Related Pumps

The District is upgrading the training of operators to assure oil levels in all safety related rotating equipment is properly maintained. The program includes:

- Review of training practices relating to oiling.
- Upgrading oiling instructions for consistency.
- Confirming proper slinger ring configuration.
- Installation of new oilers where appropriate.

(9) <u>NSCW Pump Surveillance Failure</u>

The District has evaluated the Nuclear Service Cooling Water system. The attachment provides a description of the system balancing performed to optimize a nominal system flow rate.

(10) <u>Housekeeping and General Surveillance in Safety Related Areas</u>

The District is conducting a housekeeping review in safety related areas. Management has directed that walkdowns be used to observe evidence of oil leaks, covers in place, fasteners properly engaged, etc. The District will use these walkdowns to document and evaluate any findings to confirm that operability is not degraded.

(11) <u>Valve Configuration Walkdown</u>

The Rancho Seco Operations Department has conducted walkdowns of selected systems to verify valve configurations. This walkdown includes assuring that valves required in the procedures are tagged and identified. The P&ID's were compared for correctness and any discrepancies were dispositioned by a non conformance report. Other than the valve on the MSR that initiated this effort, the walkdown team found only one nonconforming valve, associated with a steam trap, that could affect system function.

The District is also including the latest revision of the <u>Action List</u> that identifies the resolution program. As noted in the status column, almost all the items the District identified to close prior to criticality are indeed complete. The remaining startup required tasks will be closed prior to power escalation. Also, as discussed in the October 14 letter, the District will submit its status of the identified short range items as well as the schedule for completion of the long term tasks by November 18, 1985.

At the conclusion of the October 23 meeting, the District agreed to describe its actions to further enhance the reliability of the Rancho Seco Feed Water systems. The District will:

- Perform a reliability study of the Rancho Seco AFW system. The District and other utilities with similar AFW configurations, will meet with NRC staff to agree on the methodology and schedule. The District anticipates this initial meeting will occur within the next several weeks. The projected completion of the reliability study has a tentative date of mid-1986.

- Scrutinize priorities, using its Living Schedule program, in an attempt to accelerate the implementation of Emergency Feedwater Initiation and Control (EFIC). This is a full safety grade initiation and control AFW system. Although scheduled in two phases with final implementation by Cycle 9 startup, the District believes it can complete a majority of the EFIC modifications during the next refueling outage. To accomplish this, the District will adjust the Living Schedule by deferring items that do not significantly affect the safety or reliability of the plant.

- As discussed during the October 23 meeting, the District has committed to the development of a preventative and predictive maintenance program for the secondary side of the plant. The District has also embarked on a "root cause" program that will investigate significant failures of the MFW and AFW systems. These investigations will result in corrective actions to reduce challenges to the AFW system.

- Other areas along the above lines that the District is pursuing include:

  - Instrumenting the MFP's to determine the root cause of trips.

  - Participating in the B&W Owner's Group MFP reliability program.

  - Tuning the ICS to allow it to run more efficiently.

  - Engineering studies to determine possible enhancements to the main feed pump control system.

The District believes the information being provided as attachments to this letter completes our response to all requests for information related to the concerns over the October 2, 1985 Reactor Trip at Rancho Seco. The Confirmatory Action Letter of October 4, 1985, requested a briefing of our assessment of the root cause and justification as to why the Rancho Seco facility is ready to resume power operation. We have held numerous telephone conversations with Region V, NRR, and I&E; have participated in several inspections on site; have met with NRC staff on October 10, 11 and 16, 1985 at Rancho Seco, and on October 23 in Bethesda, MD; and have submitted correspondence dated October 14 and October 18, 1985, plus this letter. We are satisfied all commitments have been met and that Rancho Seco is ready to resume power operations.

R. J. RODRIGUEZ
ASSISTANT GENERAL MANAGER,
NUCLEAR

Attachments

ATTACHMENT 1

Main Feedwater Pump Trips - Analysis and Findings

1. Introduction

On October 2, 1985, the day of the event, a program of detailed investigation into the causes of both Main Feedwater Pumps (MFPs) tripping was initiated. This effort took advantage of the following sources of information:

- Memory Trip Review, computer data showing alarms and logs of selected parameters,
- Operator logs and reports,
- Operator interviews,
- As found calibrations of trip devices,
- Plant design and configuration data,
- Relevant operating procedures,
- Equipment Supplier Field Engineers,
- Nuclear Utility Industry Consultants,
- Plant maintenance history,
- Plant history and reliability data

Due to the complex nature of the event, which at one time or another, included the combined effects of a "Loss of Condenser Vacuum," "Loss of Main Feedwater," and "Rapid Cooldown" events, it was necessary to proceed in a number of simultaneous investigations so as to gain a full understanding of the expected behavior of the MFPs, and determine the cause of their tripping. This effort was necessary, and made quite complex, as a result of only one of the potential tripping parameters having been provided with a "seal in" indication requiring a conscious act to reset. That one was the "Turbine Thrust Bearing" trip with the other trips self resetting. The following report summarizes the activities of the investigating team and presents their findings.

2. MFP Trips, Interlocks, and Alarms

The following are automatic MFP Turbine trips which operate through the MFP control scheme:

	Setpoint
Pump High Discharge Pressure, Instantaneous	1650 ± 10 psig
Pump Discharge Pressure, Time Delay	1575 ± 5 psig for 5 sec
Thrust Bearing Wear, Normal	0.040 ± 0.001 inches
Thrust Bearing Wear, Reverse	0.007 ± 0.001 inches
Low Lube Oil Pressure	10.5 ± 0.5 psig
Manual (Remote, or Local) Pushbutton	Contact

The following trips are mechanically operated at the MFP turbine:

Overspeed	5800 ± 20/-100 RPM
Mechanical	Lever

All trips function by dumping AUTOSTOP OIL pressure to the reservoir, depriving the stop valves of pressure necessary to hold them open, and the governor valves of the CONTROL OIL pressure necessary to position the governor valves.

There are no condenser vacuum, vibration, or low pump suction pressure trips. Low pump suction pressure does auto start an additional condensate pump. Low autostop oil pressure gives the "Tripped" indication, closes the MFP turbine stop valves, and initiates a reactor anticipatory trip signal. ARTS trip blocked at <20% power. Any of the MFP control scheme trips also sends a permissive signal to the ICS allowing automatic control of the auxiliary feedwater control valves. Vibration, bearing temperatures, and a number of autostop oil, lube oil system, and control system parameters are alarmed either in the Control Room, or on the computer.

3. Scenarios Considered in MFP Trip Investigation

A summary of the major scenarios considered as possibly creating the trip condition follows. It was always considered a "given" that both MFPs did in fact "trip," and that the trip condition was real. This was due to the observation that upon trip of the second MFP, i.e, B-MFP, the ICS controlled auxiliary feedwater valves immediately began delivering AFW to the OTSGs. The only way this signal can be generated is for a trip signal to each MFP's AUTOSTOP OIL DUMP solenoid to exist and be "latched" by the in-parallel holding coil, thus both MFPs were "tripped."

a. MFW Pressure Spikes to $\geq$ 1575 psig

1. Main or Startup FW Control or Block Valves movement causing MFW pressure spikes/oscillations.

2. Water hammer in secondary plant feedwater piping.

3. Cavitation at MFP suction, (inadequate NPSH).

4. Flashing at MFP due to overheating at 4th Point Feedwater Heaters.

b. Autostop, Control, Bearing Oil System Pressure Transients

1. Rapid demand changes in Governor Valve position.

2. Setpoint overlap and correctness.

3. "Trip Signal" to Stop Valves without trip of Autostop Oil.

4. A-MFP Trip Investigation

A review of each of the trip parameters follows:

a. Pump/Turbine Overspeed Trip

Prior to the A-MFP tripping, it had been in manual control maintaining approximately 3450 rpm. Six minutes prior to the A-MFP trip, the generator OCBs were opened followed by the loss-of-vacuum event. Within two minutes, vacuum had dropped to approximately 20 inches Hg and the Turbine Bypass Valves locked out, steam header pressure control transferred to the Atmospheric Dump Valves. Steam header pressure immediately began rising to the correspondingly higher controlling setpoint which resulted in an increase in A-MFP speed of approximately 400 rpm. This suggests that the steam supply to the A-MFP was at that time coming through nearly full open LP

4. a. (Continued)

Governor Valves from the Auxiliary Steam System. Coincident with the shift from bypass to atmospheric valve control of header pressure, the 4A Feedwater Heater shell reliefs had opened releasing approximately 280,000 lbm/hr to atmosphere at a pressure of approximately 150 psig. The source of this steam was primarily from Main "Pegging" steam, while the auxiliary steam load was carrying the balance of plant steam loads. Since the LP Governor valves were nearly full open, any change in auxiliary steam pressure would result in a corresponding change in steam available to the A-MFP LP Steam chest. Approximately two and one half minutes after the Bypass/Atmospheric valve transfer, the LP Governor valves were full open and condenser vacuum had further degraded to approximately 15 inches Hg. This resulted in a rapid coastdown of the A-MFP Turbine, as it was still under load. A-MFP delivery of feedwater to the OTSGs had dropped to zero by the time the A-MFP Turbine tripped at 01:32:01. At the time the A-MFP Turbine tripped, its speed had decayed to approximately 2500 rpm.

Review of the MFP control scheme also shows that the overspeed trip of the MFP does not initiate a trip of the autostop oil trip solenoid, thus the signal to the ICS permitting automatic control of the Auxiliary Feedwater Control Valves is not operated.

For the above reasons, it is concluded that the A-MFP did not trip on overspeed.

b. Instantaneous Pump Discharge Pressure $\geq$ 1650 psig

At the time of the A-MFP trip, the feedpump was delivering water at a pressure less than that necessary to inject water into the OTSGs. OTSG Steam Header pressure was approximately 925 psig at this time. During the preceding minutes, in which there had been sizeable feedwater flow oscillations, the feedwater control valves had seen differential pressure of as much as 300 psi. If an allowance for OTSG and piping losses of 75 psi is added, the maximum possible feedwater header pressure would not have exceeded 1300 psig, well below the 1650 $\pm$ 10 psig trip setpoint. With the pump speed down to approximately 2500 rpm, it is not possible for the pump to generate pressure of this magnitude. Alternative events were considered, specifically, water hammer caused by rapid closure of the FW control valves, or block valves, cavitation or flashing at the pump suction, and instrument failures.

4. b. 1. Rapid Closure of FW Control or Block Valves

At reactor power of approximately 15%, the ICS will transition from the Main to Startup FW Control Valves, and close the Main Block Valve. For the three minutes prior to the A-MFP failing to develop flow into the OTSGs, a relatively smooth increase in FW flow was observed. This suggests that the main to startup transition had already occurred and that there were no significant oscillations occurring, certainly none which could be categorized as "water hammer" due to control valve transients; secondly, as a result of the low MFP discharge pressure at the time of the trip, the MFPs were "isolated" from the control valves by the discharge check valves. Since this pressure switch is located on the open cross-tie between the A and B MFPs, downstream of the MFP Check Valves, and the B-MFP did not experience a coincident trip, pressure spikes could not have caused the trip.

2. Cavitation or steam flashing events likewise could have caused pressure spikes, but for the reasons above, these did not trip the MFPs.

Independently, the A-MFP suction temperature was observed to increase from a value of approximately about 205°F fifteen minutes before the A-MFP trip to a steady 360°F at the time of the trip. At this temperature, 160 psia is required to maintain subcooled saturated water, also, about 40 psia is required to assure NPSH requirements for the pump. The system is provided with an autostart of a condensate pump at a low MFP suction pressure of 230 psig. Neither of the standby condensate pumps autostarted, hence, it is concluded that adequate suction pressure existed to preclude flashing or steam binding as a source of pressure spikes. Furthermore, operators and engineers present in the turbine building and MFP vicinity, did not observe water hammer or unusual noises other than those expected for the existing conditions.

3. Instrumentation

Following the event, several calibration checks were performed on the A-MFP high dishcarge pressure (instantaneous) pressure switch and all were within specification. Later, in the process of installation of trip parameter contact monitoring devices, it was noted that the pressure switch which developed this signal was in a "tripped" condition. At the time, the

4. b. 3. (Continued)

A-MFP was on clearance for control system troubleshooting. Investigating the cause of the intermittent switch condition determined that corrosion was present at the terminals of the pressure switch assembly. This could have provided a path for the 125 vdc power to bypass the actual bourdon tube actuated microswitch. The initial failure was random although the combined vibrations from nearby relief valve operations probably accounted for the A-MFP trip on an "apparent" instantaneous high discharge pressure.

c. Time Delayed High Discharge MFP Pressure

All of the factors and events imparting the likelihood of the instantaneous high discharge pressure are appropriate to this trip parameter. They are located adjacent to each other and sense the same source of pressure. This switch was found to have similar corrosion, although there is no indication that a trip signal was generated by this device. This parameter was not considered to be a source of the trip.

d. Low Lube Oil Pressure

Several hours following the A-MFP trip, it was noticed that both the lead and backup AC Lube Oil Pumps were operating. A single pump is normally sufficient to provide the autostop, control, and bearing lube oil requirements. Queries to the operators determined that the second pump was not manually initiated. Since the low lube oil pressure trip of the A-MFP is associated, a detailed investigation was pursued to determine if this was a likely source of the actual A-MFP trip. By comparing these actuations to the diverse alarms or actuations which actually occurred, it is possible to determine whether or not this was the source of the trip. Note that a check of the setpoints of these devices found them to be in specification.

The backup lube oil pump starts on autostop oil pressure decreasing to 160 ± 2.5 psig. Efforts to simulate rapid governor valve motion did create oil pressure fluctuations which were sufficient to autostart the backup oil pump. This condition has been observed in other facilities with similar arrangements. Given the complexity of events preceding the A-MFP trip, it is likely that the backup pump did autostart as a result of rapid governor valve motion and not as a result of the failure of the lead pump.

4. d. (Continued)

The DC Lube Oil Pump was not found to be inservice. It autostarts at 10.5 psig and insures that the turbine bearings are not damaged due to insufficient lubrication. There is an alarm on the Lube Oil System at 15 psig. It was not received. It is concluded that there was no failure of the AC Lube Oil Pumps.

The operators observed the A-MFP "Trip" light illuminate at their Control Room panel. This was recorded by the computer alarm monitor as was the coincident event of all four ARTS trip switches signaling their respective Reactor Protection System channels.

The A-MFP Low Lube Oil Trip occurs at 10.5 ± 0.5 psig. The alarm on Low Lube Oil Pressure was not observed by the computer, nor was the DC Lube Oil Pump autostarted. From this, it is concluded that there were pressure fluctuations in the autostop oil system sufficient to autostart the backup AC Lube Oil Pump, but that the A-MFP trip occurred prior to any Low Lube Oil Alarm, or condition, which would autostart the DC Lube Oil Pump. The A-MFP did not trip on Low Lube Oil Pressure.

e. Thrust Bearing Wear, Normal or Reverse Direction

The degrading vacuum condition on the A-MFP turbine exhaust would cause a shift in thrust as seen at the thrust bearing, compounded by the changes in steam flow, and supply pressures, and the balancing thrust generated by the main feedwater pump itself.

Thrust bearing trips are the only trips which have a "seal-in" feature requiring operator action prior to allowing the MFPs to be reset. No such operator action was required in this event. While this precluded a thrust bearing trip, an investigation was carried out to determine the thrust bearing condition and the viability of the "seal-in" feature. Disassembly of the thrust bearing housing sufficient to allow inspection and thrust bearing "trip" verification was done. Operation was as expected, although the as found settings of the trip probes were found to require adjustment. This did not change the observation that a valid trip had not, nor should not have occurred, nor that if one had, it would "seal-in." Thrust bearing wear did not cause the A-MFP to trip during the event.

4. f. Manual Trip

The A-MFP Autostop Oil System can be electrically tripped from the Control Room or from the local control panel. It can also be tripped by manually actuating the overspeed trip device on the MFP Turbine. Interviews with both licensed and non-licensed operators and observers confirms that the A-MFP was not manually tripped.

g. A-MFP Seal Water

Several minutes prior to the A-MFP trip, an operator called the Control Room and reported that the A-MFP was blowing "steam" from its bearing glands. The Control Room Operator immediately began increasing B-MFP speed in preparation for placing the B-MFP inservice and tripping the A-MFP. This was not completed prior to the actual A-MFP trip; thus, when the trip came, the B-MFP was still at idle speed. Prompt action by maintenance personnel repaired the seal water regulator control linkage which had lost a pivot pin. This incident complicated the overall event, but did not damage the pump or impact the outcome.

5. B-MFP Trip Investigation

A review of each of the trip parameters follows:

a. Pump/Turbine Overspeed Trip

Seven minutes prior to the Main Generator being taken off-line, adjustments were made in attempt to increase the B-MFP turbine speed. These adjustments were not effective in increasing the unit's speed, which continued at a nominal 2450 rpm, and seemed to be matched to parallel changes in the steady state speed of the A-MFP. It is likely that these changes in speed are the result of changes in the auxiliary steam supply pressure which was being driven by concurrent changes in the main steam header pressure. At the time of the A-MFP trip, the B-MFP speed began to decrease below its idle speed. Attempts by the operator to increase its speed had not produced observable results, although the LP governor valve was caused to drive full open by the speed demand. B-MFP tripped approximately 30 seconds after the A-MFP. Both pumps show a fairly extended coastdown to turning gear speed which is attributed to leakage past the stop valves.

There was insufficient energy available to the B-MFP to accelerate it above its idle speed at the time of its trip. The B-MFP did not trip on overspeed.

5. b. Instantaneous Pump Discharge Pressure $\geq$ 1650 psig

The discussion in 4.b above, applicable to the A-MFP, is directly applicable to the B-MFP with the exception that no problems have been found in its pressure switches. In adddition, since the pump was at only idle speed, it could not have generated overspeed conditions commensurate with a high discharge pressure trip.

c. Time Delayed High Discharge MFP Pressure

As discussed above, this trip could not be generated by the pump. Only instrumentation problems, which were not observed, could cause this parameter to trip. Based upon this analysis, the B-MFP did not trip as a result of this parameter.

d. Low Lube Oil Pressure

Only one lube oil pump was inservice and neither the AC or DC backup pumps were found on. Likewise, there were no pressure alarms received prior to the trip. The instruments were found to be properly calibrated.

The investigations into the autostop, control, and lube oil systems done on the A-MFP are applicable to the B-MFP and support that the B-MFP did not trip on low lube oil pressure during the event on October 2.

e. Thrust Bearing Wear, Normal or Reverse Direction

The B-MFP turbine exhaust steam discharges into the same condenser vacuum as does the A-MFP turbine. If the significant degradation of vacuum (increase in backpressure) caused the trip, then it would be expected to have caused the trips on both units. Although the trips occurred only 30 seconds apart, the fact that a detailed inspection of the A-MFP Thrust Bearing, and its associated trip device, did not suggest the generation of a thrust bearing wear trip can likewise be excluded from having occurred on the B-MFP. In addition, the operators did not reset any thrust bearing trips in their efforts to reset the B-MFP following its trip on October 2. Finally, the running speed and degraded steam supply at the time of the trip were such as to preclude significant thrust loads of the nature which would be necessary to cause a thrust bearing wear trip.

5. f. Manual Trip

Several minutes prior to the MFP trips, the operators had faced several episodes of main feedwater oscillations, followed by a call from a plant operator that the A-MFP was blowing steam from its gland seals. The operators were attempting to bring the speed of the B-MFP up to the point where it could supply feedwater to the OTSGs in preparation to tripping the A-MFP. Several relief valves in the secondary plant were noisily blowing, the main generator had been manually tripped, and condenser vacuum was rapidly decreasing. At this point, the A-MFP tripped and the operator noted that both Auxiliary Feedwater Pumps had autostarted (on Main Feedwater Header Pressure < 850 psig) and that OTSG levels were rapidly falling in response to the large steam loads then existing (the main turbine had not tripped on low-vacuum) and the reactor was still at a nominal 15% FP. The B-MFP was not responding to operator inputs to increase its speed and a Reactor/Turbine trip then occurred. Operator training in ICS operation tells them that upon tripping of both MFPs, or all four Reactor Coolant Pumps, the ICS controlled auxiliary feedwater control valves will operate to maintain OTSG level. With an immediate need to provide feedwater to the OTSGs, with the knowledge that both Auxiliary Feedwater Pumps are operating, and prior training that tripping both MFPs will provide auxiliary feedwater to the OTSGs, the operator probably tripped the B-MFP manually from the Control Room.

Post trip discussions with the operators did not get a definitive "...I tripped the B-MFP..." response. Rather it was "...I may have tripped the B-MFP..." Subsequently, the operator said that, "...I probably tripped the B-MFP..."

This lack of clear memory is not considered to be inappropriate. At the point when the B-MFP tripped, there was a lot happening in the plant with the immediate need being to get feedwater into the OTSGs. It is in such situations that the benefit of training is most important, and immediate action to trip the recalcitrant B-MFP and obtain the needed feedwater from an available, and diverse, auxiliary feedwater system is entirely appropriate. In fact, a similar situation is a part of the operator training syllabus on the plant simulator. Manually tripping the B-MFP was not a "memorable" action, it was a trained response to the conditions the operator faced.

6. Auxiliary Steam Supply

Each of the MFP Turbines are provided with two sources of driving steam, identified as to the steam chest they supply, the LP (Low Pressure) and HP (High Pressure) steam chests.

LP steam is the perferred source. It is used during startups and for operation up to the normal full load, as each MFP is rated for about "half capacity" of plant demand. Should only a single MFP be available, it can supply feedwater demands up to at least 80% full power by the addition of steam from the HP chest. HP steam is taken directly from the main steam lines at a nominal 885 psig and admitted through the HP governor to the MFP. As HP steam is high valued economically, generating considerable revenue when expanded in the main turbine, the HP chest is not intended for use during normal operation.

LP steam comes from the auxiliary steam header during startups, shutdowns, and during periods of lower power operation. When the main turbine/generator is on-line, hot reheat steam is drawn from the moisture separator reheaters and routed to the MFP Turbine LP steam chest. A pressure regulator reduces the demand for auxiliary steam as the hot reheat steam pressure increases with main turbine load. At about 40% full power, hot reheat steam is entirely sufficient to provide the demands of the MFPs and the use of auxiliary steam is curtailed. Upon power reductions, the auxiliary steam regulator will open to maintain the supply to the LP chests between 150 to 250 psig as set by the operator.

During the October 2 event, the HP steam chest's steam supplies were manually isolated. This condition has existed since plant heatup the week before as a method for minimizing leakage through the HP stop valves and thereby enabling the plant to sustain a "Hot Shutdown" condition. As described above, the HP steam would not have been needed until the plant was to be escalated above 50% FP.

The supply of auxiliary steam was coming from one of the main steam headers via a pressure reducing and desuperheating station. Normal auxiliary steam header pressure is 250 psig. Although no actual data is available on auxiliary steam pressure up to the time of the MFP trips, there were no low pressure alarms so it can be assumed that adequate steam was available, at least up to the controller to the MFPs.

From this review it is apparent that the MFP LP Governor Valves were properly responding by stroking full open just prior to the MFP trips, and that the MFP Turbines were not able to develop accelerating torque in the existing conditions.

7. Effect of Resetting a MFP Turbine Trip

Following the MFP trips, the operators attempted to reset the trip. The efforts were unsuccessful until about twenty minutes later when the B-MFP was reset and immediately, the auxiliary feedwater valves closed.

Investigation into these two conditions showed that both were appropriate and could have been anticipated.

The MFPs will not reset unless both of the governor steam stop valves are closed, and there is no "demand" signal to the governor which would cause it to be open when steam is again supplied. After several attempts to "reset," the operator drove the speed "demand" to zero and the reset was subsequently effective. The demand signal was that which had existed at the time the MFP had tripped.

A successful "reset" removes from the ICS the indication that the MFPs are tripped, thus returning the auxiliary feedwater control valves to "zero" or closed. This requires the operator to take the valves in "manual," which was done, and appropriate feedwater flow continued. Prior to plant restart, the AFW control logic will be modified to initiate ICS control of AFW valves on the same parameter as that which initiates AFW pumps, low MFP discharge pressure.

8. ICS Performance

Several of the occurrences during the transient initially suggested that the Integrated Control System (ICS) may have been a source of the problems observed. Those modules which were suspect were checked and found to be properly calibrated and serviceable. Analysis shows that, as a system, the ICS performed as expected, including its interface with the MFPs through the Lovejoy controllers. Likewise, the investigation into the operation of the Lovejoy controls verified that they operated correctly.

A recommendation coming from this investigation is that during power escalation, a program to "tune" the ICS/MFPs be implemented to validate the interface and improve operator confidence in automatic control of the MFPs.

9. Conclusions

a. The A-MFP trip was caused by a defective High Discharge Pressure Switch. Switch actuation coincident with the event was probably the result of vibrations due to the transients in progress.

9. Conclusions

   b. The most probable cause of the B-MFP trip was an operator manual trip so as to obtain auxiliary feedwater flow to the OTSGs during a period when the secondary plant was in a complex upset condition.

   c. The MFPs, their controls and operator training, are adequate to support power operation.

   d. The addition of trip monitoring circuitry to the MFPs will significantly enhance future efforts to investigate MFP trips.

ATTACHMENT 2

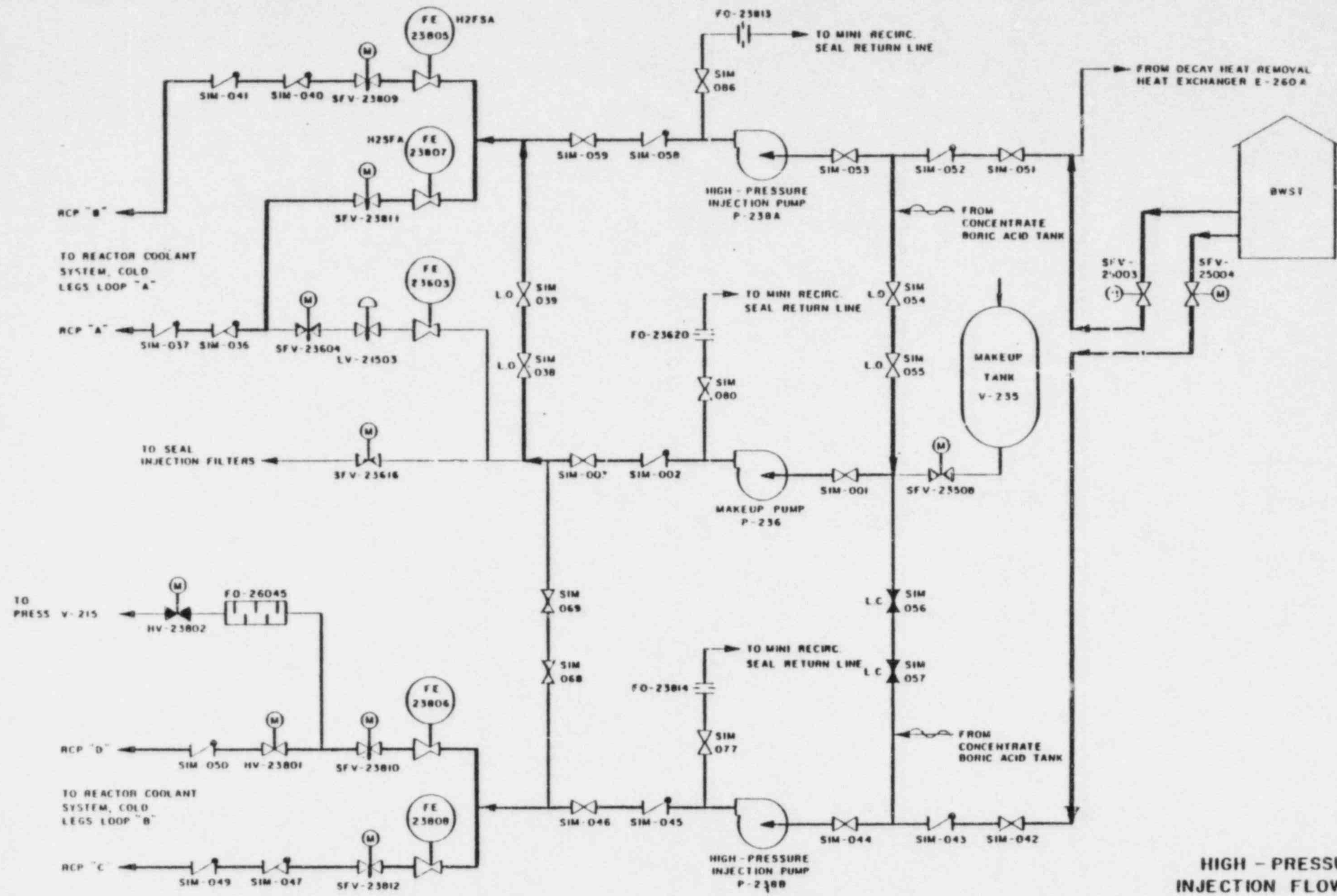
HPI "A" FLOW ANOMALY

As prescribed by plant operating procedures for pressurizer level decreasing below 100 inches, the operator started the High Pressure Injection (HPI) pump (P-238 B) lined up to the borated water storage tank and opened loop "A" HPI valve. The loop "A" nozzle is also the path for normal additions necessary to maintain pressurizer level. Although the above actions increased flow to the reactor coolant system (RCS), the pressurizer level continued to decrease. The operator opened the remaining three loop HPI valves, allowing HPI flow through all four paths to the RCS. At this point, he observed "zero" flow on the "A" HPI flow indicator. To further augment the HPI supply, he started the third HPI pump and the loop "A" HPI flow increased to about 80 gpm. Subsequent analysis of plant computer data verified this phenomenon and showed a recovery of flow indication in about 30 seconds, coincident with start of the third HPI pump.

The District has performed an exhaustive investigation consisting of system flow testing, non-destructive examination and formal analysis. This investigation led us to the root cause; a shift in the zero point of the flow transmitter. This shift occurs as the device is calibrated with the system depressurized and then brought to system operating pressure. In the case of these transmitters, this shift can result in no flow indication with as much as 75 gpm of actual flow. Note that, although this problem creates imprecise indication to the operator, it did <u>not</u> affect the ability of the HPI system to perform its safety function. Hydraulic calculation showed that, for the period of "zero" flow indication, the expected loop "A" HPI flow would be nearly identical to the measured zero shift.

Review of literature and discussions with the manufacturer of the transmitter has shown that this shift is not an equipment failure but inherent with the device. We are currently evaluating the implication of this finding with regard to this application and all other safety related applications of this transmitter at Rancho Seco.

Both the initial flow indication problem and the generic implications of our findings will be resolved, including an acceptance by the Plant Review Committee prior to plant restart. A followup report will be submitted to the NRC.



HIGH - PRESSURE INJECTION FLOWPATH

ATTACHMENT 3

HEAT BALANCE FOR COOLDOWN OF 10/2/85 TRANSIENT

Subsequent to the Reactor Trip, the temperature decrease of the Nuclear Steam Supply System (NSSS) was greater than normal.

When steam flow through the main turbine decreases to the point that insufficient extraction steam flow is available to maintain feedwater inlet temperatures to the steam generators, the pegging steam control valves are automatically enabled. The pegging steam lines direct steam from the main steam line to the two second point feedwater heaters and the two fourth point heaters.

The primary cause of the rapid cooldown was steam exhausting from two pressure relief valves on one of the fourth point feedwater heaters. The setpoints of the relief valves and the heating steam supply regulator to the feedwater heater overlap. This overlap of the inlet steam setpoint and the relief valve setpoint, resulted in an open pathway between the main steam header and the atmosphere. This pathway allowed approximately 285,000 lbm/hr of steam to escape from the main steam header and thus remove heat from the NSSS. The plant operators entered the Emergency Operating Procedure for overcooling and identified and isolated the pegging steam line, ending the transient.

The normal post trip steam loads are the pegging steam, the condenser air ejectors, the main feedwater pumps and the gland or sealing steam for the turbine seals. In addition to the normal plant steam loads, several other abnormal steam or heat loads were associated with this reactor trip.

The estimated steam loads are listed below:

Main Air Ejectors	1,560 lbm/hr
Hogging Air Ejectors	13,800 lbm/hr
Gland Steam Condenser	9,600 lbm/hr
Auxiliary Feedpump Turbine	32,500 lbm/hr
Pegging Steam Condensation	109,000 lbm/hr
Pegging Steam Relief Valve	285,000 lbm/hr

NOTE: Actual average pegging steam load was limited to 360,000 lbm/hr by the maximum flow capacity of the pressure control valve on the 4A feedwater heater which is less than the relief valve capacity and condensation rate at main steam pressures less than 852 psig.

The overall steam load on the NSSS after the trip was calculated to be about 417,000 lbm/hr, of which 86% was the pegging steam load. Without the relief valves opening on the 4A heater, there would not have been a rapid cooldown.

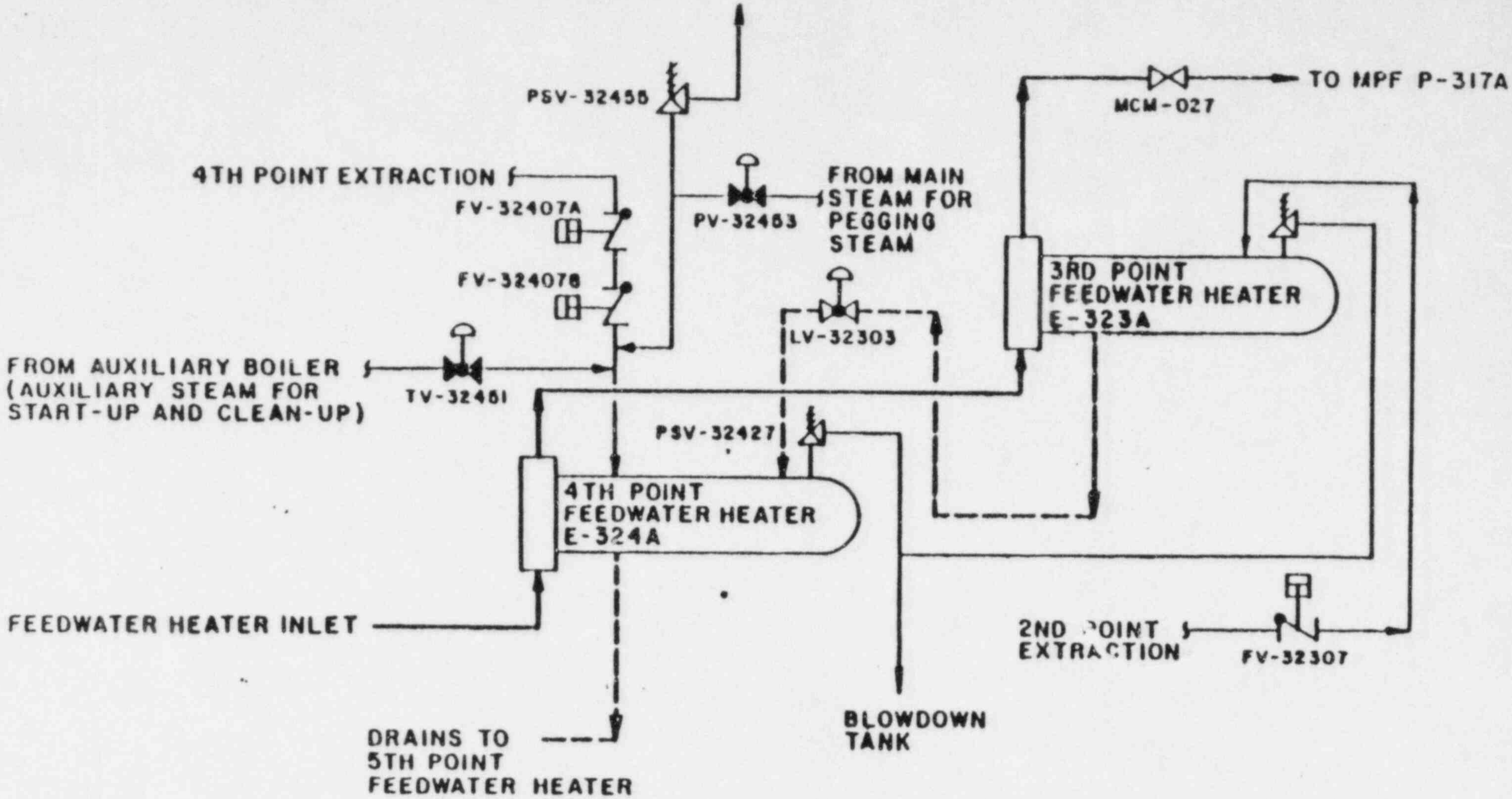
An engineering evaluation verified that the estimated steam loads were consistent with the Auxiliary Feedwater flow rate and the Steam Generator level following the transient. This engineering evaluation also considered the depressurization of the secondary steam system. This depressurization from 945 psig to 622 psig in seven minutes would indicate a loss of approximately 83,250 lbm/hr from the secondary steam system over the calculated steam generation rate of 300,000 lbm/hr. This system has a total volume of approximately 12,500 Ft^3.

The engineering evaluation also verified that the observed steaming rate was consistent with the heat removed from the primary system.

The calculated heat removal rate from the primary system was based on cooling down the RCS, excluding the pressurizer, from 553.4°F to 501.1°F in seven minutes. The principal results of this calculation were:

Average Decay Heat	58 MBtu/hr
Pump Heat Input	82 MBtu/hr
Net Heat From Coolant	141 MBtu/hr
Net Heat From Metal	103 MBtu/hr
TOTAL	384 MBtu/hr

Average Heat Removed by Letdown	3 MBtu/hr
Heat Transfer to OTSGs	381 MBtu/hr



SIMPLIFIED DIAGRAM OF LOW-PRESSURE FEEDWATER HEATERS 3A & 4A

ATTACHMENT 4

EVALUATION OF THE REACTOR VESSEL COOLDOWN

Following the transient of October 2, 1935, the effect of the rapid cooldown on the Rancho Seco NSSS integrity was analyzed. The Babcock and Wilcox (B&W) Company, manufacturers of the Rancho Seco NSSS, were contracted to perform the engineering evaluation. Their investigation showed that the structural integrity of the pressure boundary components has not been impaired and that they are suitable for continued power operation. The B&W letter, dated October 4, 1985, is attached to document this analysis.

The transient has also been compared to the transient of March 20, 1978. A graphical presentation of RCS temperature data for the two transients is also attached. The results of detailed engineering analyses of this event were submitted to the Commission in LER 78-1.

Post trip reactor coolant temperatures continued to drop from a normal post trip value of ≈550°F to 490°F in about 20 minutes. This cooldown did result in exceeding the 100°F per hour cooldown rate associated with Figure 3.1.2-2 of the Technical Specification for Rancho Seco. The temperature did not deviate from the acceptable operation region of the figure for any pressure. This ensures that the requirements of 10CFR50, Appendix G, are met.

It must be understood that immediately following the transient, the Wide Range Cold Leg Temperature recorder was used for some of the analyses. This temperature recorder has since been found to be in error and recalibrated. The computer compiled data has been determined to be more accurate.

The District, having reviewed the B&W evaluation, has concluded that there is no concern with system integrity.

Babcock & Wilcox
a McDermott company

Nuclear Power Division
3315 Old Forest Road
P.O. Box 10935
Lynchburg, VA 24506-0935
(804) 385-2000

October 4, 1985
SMUD-85-222

Mr. R.J. Rodriquez
Executive Director, Nuclear
Sacramento Municipal Utility District
6201 S Street
Sacramento, CA 95813

Attention: Mr. George Coward
Manager, Nuclear Operations

Subject: Evaluation of 10/2/85 Rancho Seco Transient for Return to Power Operation

Reference: 1) Rancho Seco Nuclear Generating Station, Unit 1
B&W Master Services Contract Dated January 1, 1984
SMUD Contract 9759 - B&W Contract 582-7165
Task 552 - Evaluation of October 2, 1985 Transient at Rancho Seco
2) B&W Letter: Burke to Rodriguez, "Initial Evaluation of 10/2/85 Rancho Seco Transient", SMUD-85-217, October 3, 1985

Enclosure: 1) B&W Document 51-1159202-00, Rancho Seco 10/2/85 Transient Evaluation

2) B&W Document 51-1159204-00, Stress Evaluation of Rancho Seco Transient (10/2/85)

Dear Mr. Rodriguez:

B&W has performed an evaluation of the Reactor Coolant System (RCS) components for the transient which occurred at Rancho Seco Nuclear Generating Station on October 2, 1985. This evaluation was performed in two parts: (1) a brittle fracture/thermal shock evaluation of the reactor vessel (RV) beltline region and (2) an ASME Code, Section III evaluation of the primary system components. The brittle fracture/thermal shock evaluation was based on analyses previously performed for another utility. The primary system component evaluation was based on analyses performed for the rapid cooldown transient at Rancho Seco on March 20, 1978. Based on these evaluations, B&W has concluded that the structural integrity of the pressure boundary components has not been impaired and that they are suitable for continued power operation.

On October 3, 1985, we discussed with Mr. George Coward the need to perform additional fracture mechanics and fatigue analyses to more quantitatively assess the potential impact of the October 2, 1985 transient. We planned to have this quantitative evaluation completed by October 18, 1985, and Mr. Coward authorized B&W to proceed with this work. After our initial fatigue evaluation based on the March 20, 1978 transient, we no longer feel the quantitative fatigue evaluation is necessary especially if future work is contemplated to relax the operating envelop. However, since the RCS pressure did not drop in the October 2, 1985, transient as it did in March 20, 1978, we feel the fracture mechanics evaluations to specifically address the October 2, 1985 transient should still be performed. Unless you direct us otherwise, we are proceeding on that basis.

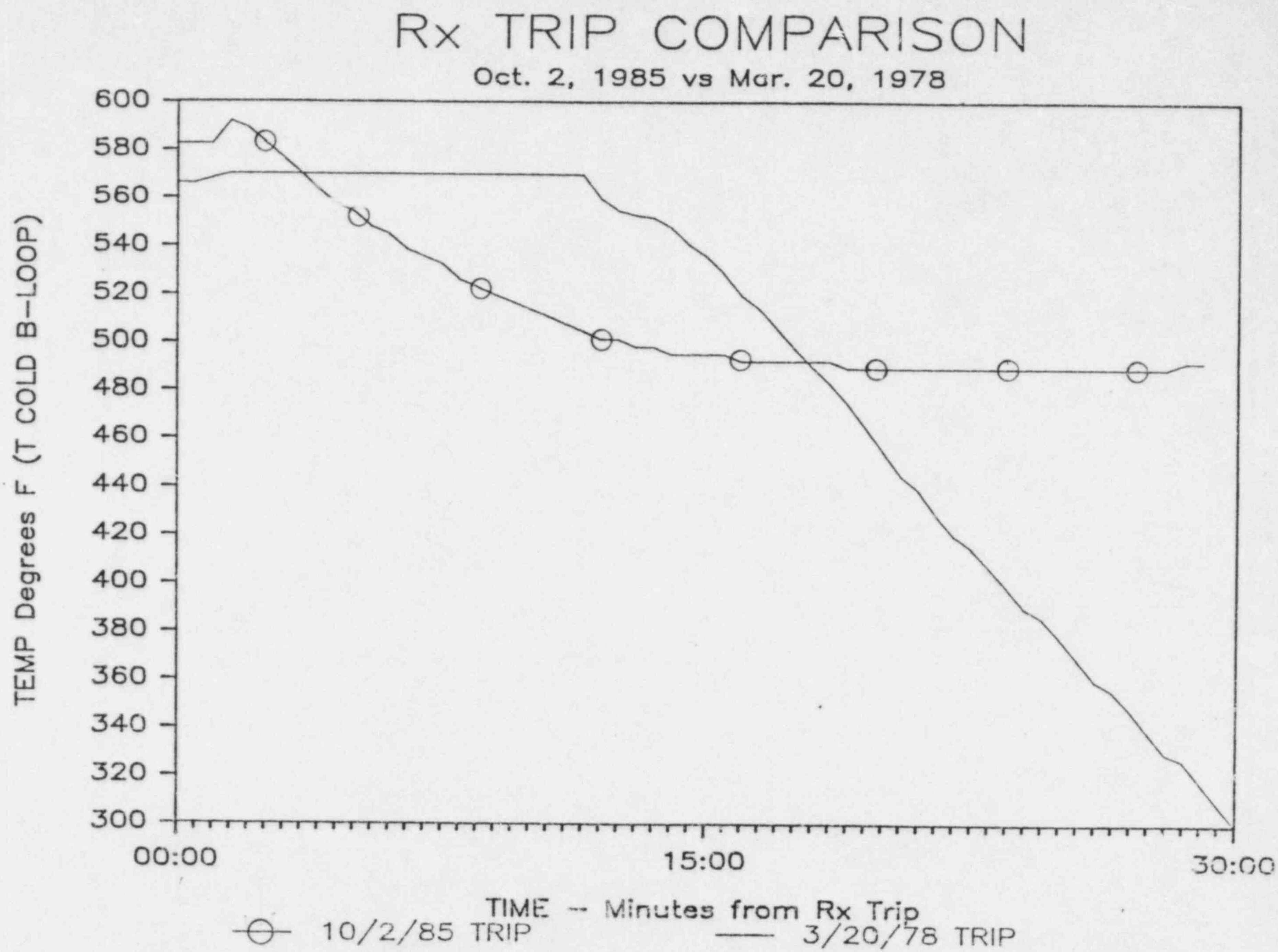
If you have any questions or need additional support from B&W, please call me at (804) 385-2308 in Lynchburg.

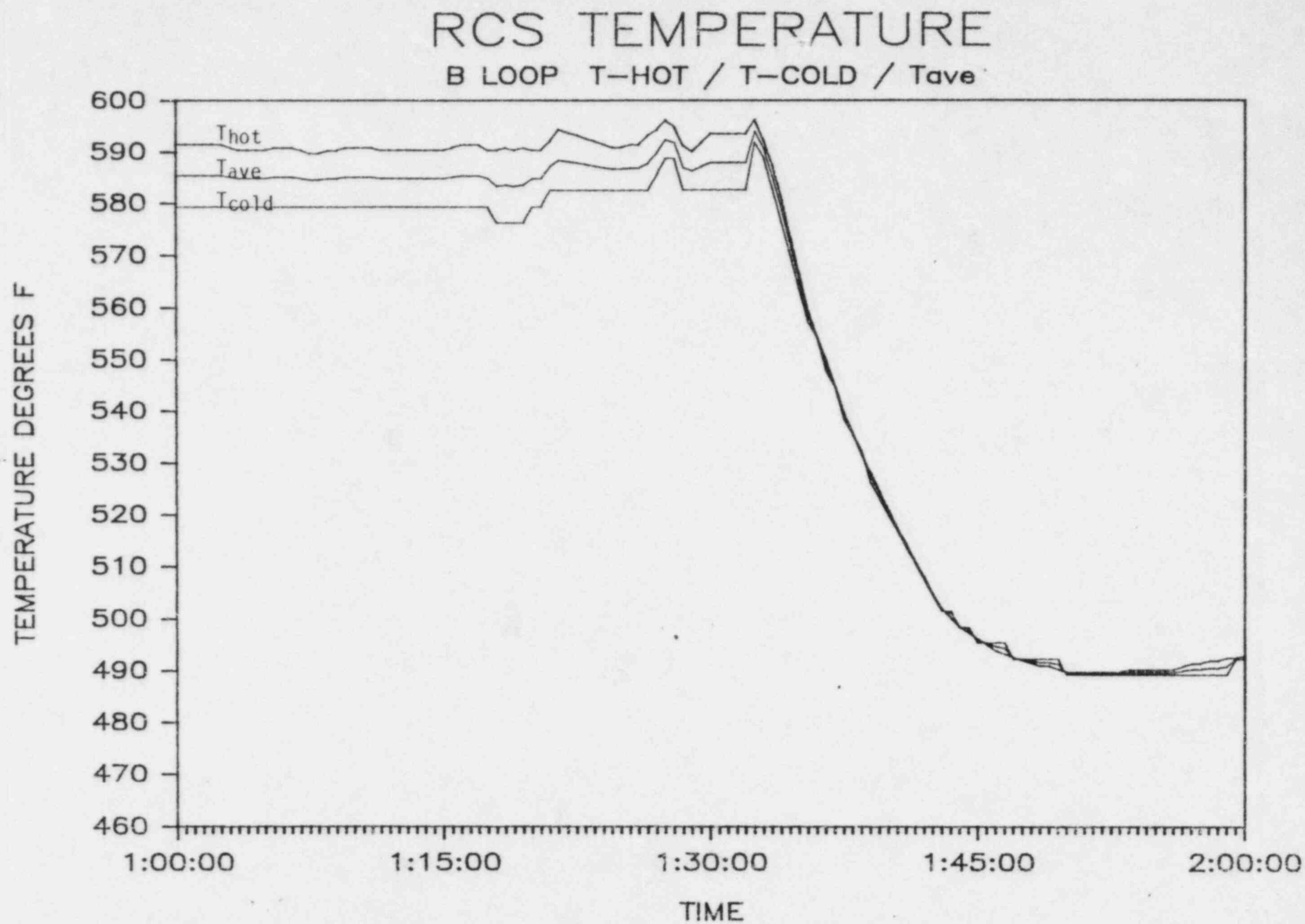
Very truly yours,

F.R. Burke
Manager of Contract Engineering
Nuclear Engineering Services

FRB/rlb

cc: L.R. Keilman
J.V. McColligan
Steve Redeker
Val Lewis
J.T. Janis
D. Abbott
J. Field


Rx TRIP COMPARISON
Oct. 2, 1985 vs Mar. 20, 1978
600
580
560
540
520
500
480
460
440
420
400
380
360
340
320
300
TEMP Degrees F (T COLD B-LOOP)
00:00
15:00
30:00
TIME -- Minutes from Rx Trip
10/2/85 TRIP
3/20/78 TRIP



T_{hot} = IDADS Pt. T 9010 T_{cold} = IDADS Pt. T 9016

ATTACHMENT 5

Part I: Auxiliary Feedwater Control Logic Modification

I. Purpose of Design Change

A. Initiate ICS control of AFW valve on same parameter as that which initiates AFW pumps, low MFWP discharge pressure.

B. Reduce probability of loss of AFW during re-establishment of MFW.

II. Summary of Change

A. Scope

The work to be performed is entirely in the ICS cabinets. This change will modify relay logic for initiation of AFW auto flow control and MFW block valves. No other systems are affected.

Wiring will be removed from contacts of 86-1/AFWPT and 86-1/BFWPT and added to spare contacts of 86/AFWPL and 86/BFWPL.

B. Design Basis

Improve probability of AFW successfully completing its design function on demand.

C. Equipment Class & Power Requirements

SMUD QA Class 2. No modifications to existing power is required.

D. Testing

A special test procedure has been written and approved by the Plant Review Committee. Testing was completed on October 25.

III. Calculations and Design Information

A. Design Features

Currently, "A&B MFW pump tripped" affects three ICS functions:

- Pseudo Auto MFW pump control
- MFW Block Valve
- AFW Valve Control

This modification has the following impact:

Pseudo Auto Control - No change.

MFW Block Valves - The "A&B MFW pumps tripped" signal will be replaced with the "MFW pumps discharge pressure low" signal. The remainder of the logic will remain the same (1 RCP tripped to close the block valve).

AFW Valve Control - The "A&B MFW pumps tripped" signal will be replaced with the "MFW pumps discharge pressure low" signal. This signal will allow the ICS to control the AFW valves on low OTSG level.

B. Functional Description

The two functional signals associated with this ECN are "MFWP low discharge pressure" and "MFW pumps tripped." "MFWP low discharge pressure" provides the best indication of MFW status. "MFWP trip" provides the best indication of MFWP not running.

- Signal to initiate ICS control of AFW flow valves will be "MFWP low discharge pressure" vs. current "MFWP trip" signal.
- Signal to MFW block valve logic will be MFWP low discharge pressure vs. current MFWP trip signal; however, it shall require at least 1 RCP tripped to activate this function, as at present.
- Signal to pseudo auto logic which is used to run MFWP speed demand to minimum will still require the MFWP trip signal in order that the MFW pumps may be started without requiring the logic to be disabled.
- Signal to ICS runback logic will remain MFWP low discharge pressure.

IV. Logic Diagram

The logic diagram from the Design Basis Report is attached. (See Figure A)

JOB NO. 1 | BY JNI | SUBJECT LOGIC DIAGRAM | DATE | SHEET NO.

SMUD-0480a 4/84

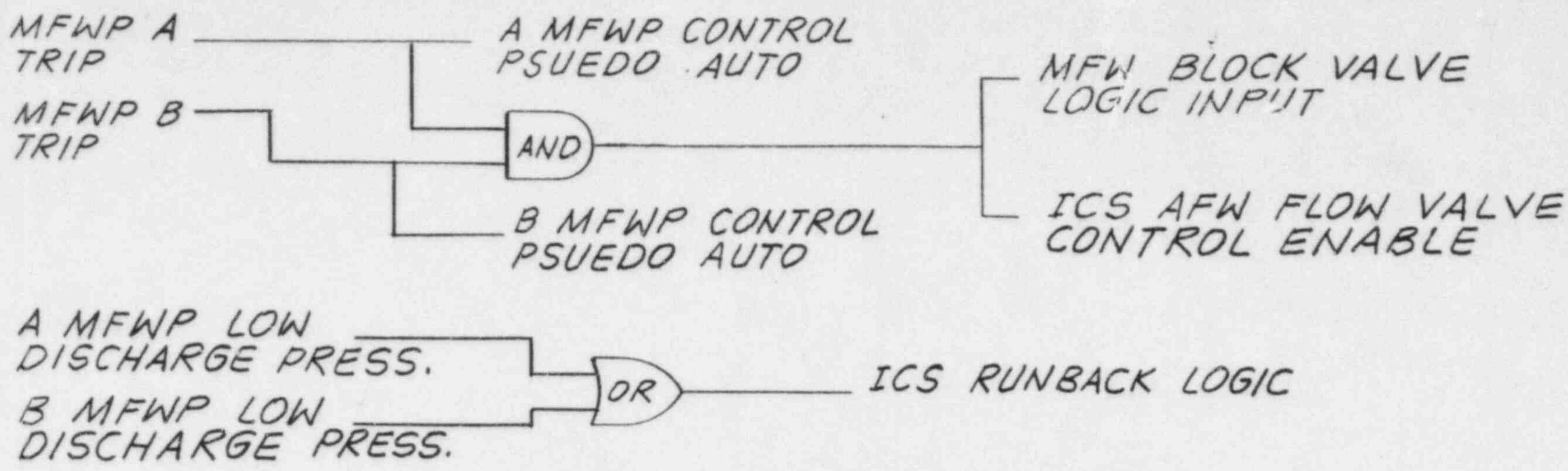


FIG. 1 - CURRENT LOGIC

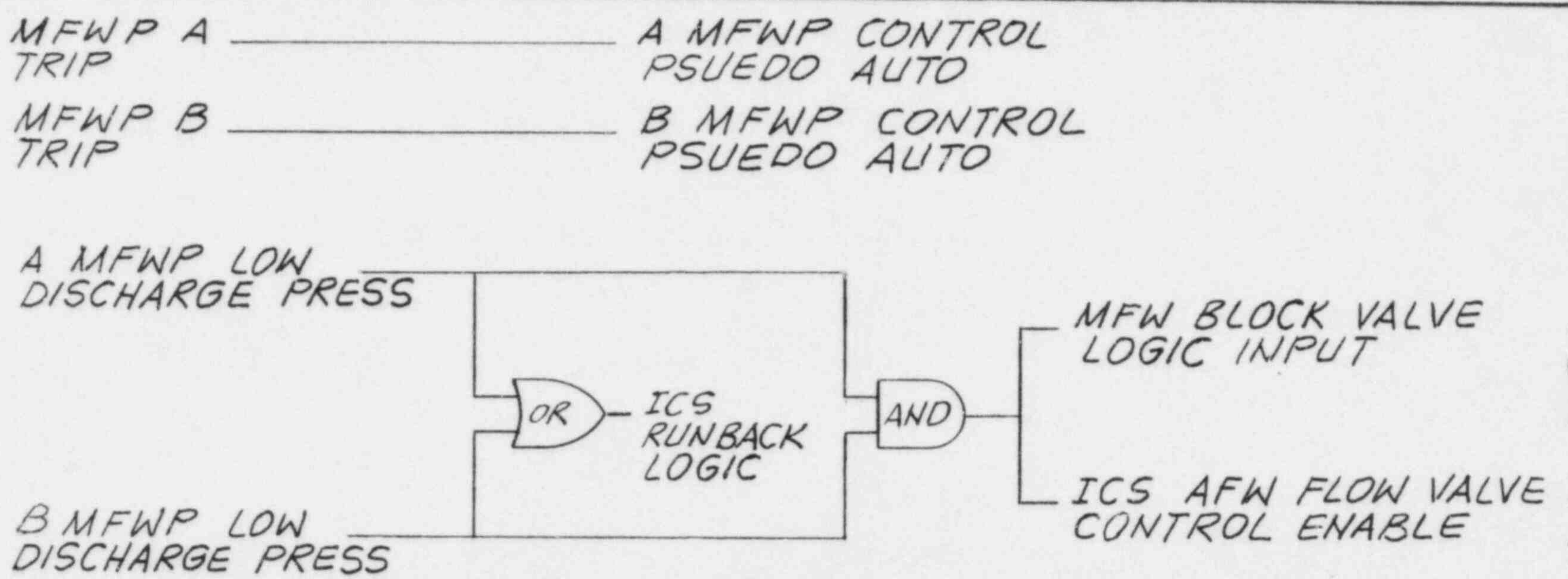


FIG. A - POST ECN CHANGE LOGIC

ATTACHMENT 5

Part II: Auxiliary Feedwater/Main Feedwater Failure Analysis

The NRC requested information regarding single failures as relating to MFW/AFW during the phone conversation of October 25, 1985. A particular question raised was: "Is there a scenario in which one failure in the ICS could close all four MFW valves, interrupting MFW to both OTSG's, and not result in automatic start of AFW flow?"

The ICS controls the MFW valves and the automatic OTSG level control AFW valves. Since the ICS is control grade and not designed to single failure criteria, it cannot be conclusively stated that the above scenario is impossible. The following discussion, however, shows that there is no single failure which can interrupt MFW flow and result in the inability to manually from the control room, provide AFW flow in a timely manner using class 1 equipment which is completely independent of the ICS.

The design of the AFW system was presented in detail to the NRC staff during the October 23, 1985, meeting in Bethesda. It was clearly shown that there are two separate and distinct activate/control systems and flow paths within AFW (see Figure B attached). Either system can supply AFW to the OTSG's regardless of failures in the other. The systems are briefly described below.

1) The first system is the ICS Control/Class 1 Pump Start System. It automatically starts and controls OTSG level when loss of feedwater/main feedwater pumps is sensed by low main feed pump discharge pressure or when all four (4) RCP's trip. Manual start and flow control is available in the control room.

   The control grade ICS, which also controls MFW, operates one of two parallel flow path valves to each OTSG (FV 20527 OTSG A, FV 20528 OTSG B). The other flow path to each OTSG is a class 1 safety feature (SFAS) valve (SFV 20577 OTSG A, SFV 20578 OTSG B). The ICS controlled FV's automatically operate to control OTSG level once main feed pump discharge pressure drops below 700 psig. A class 1 circuit (independent of SFAS) automatically starts both AFW pumps (P319 motor and P318 turbine drive) when main feed pump discharge pressure drops below 850 psig. The pumps and valves also automatically operate when all four (4) RCP's are not running, as sensed by class 1 underpower/phase imbalance monitors.

2) The second system is the Class 1 Safety Feature Activation System (SFAS). This system provides automatic AFW pump start and flow to the OTSG's when LOCA conditions are sensed. Class 1 manual start and flow control is available in the control room.

   The SFAS system operates the second of two parallel flow path valves to each OTSG (SFV 20577 OTSG A, SFV 20578 OTSG B). The other flow path to each OTSG is through an ICS controlled valve described above. The SFAS valves automatically fully open and the AFW pumps automatically start to provide AFW flow to the OTSG's upon low RCS pressure (1600 psig) or high reactor building pressure (4 psig).

The SFAS system is completely independent of the ICS/Class 1 Pump Start System. Thus, it follows that there is no single failure which could cause loss of main feedwater flow (for example, closure of all ICS controlled main feedwater control valves), and cause the inability to provide AFW flow with the SFAS system. SFAS system AFW flow would require manual control room pump start and flow control since SFAS does not detect loss of main feedwater.

Manual AFW flow start will be rapid and effective because there are specific symptom based Emergency Operating Procedures (EOP's) and extensive operator simulator training regarding loss of main feedwater events. The loss of main feedwater would result in a reactor trip on either anticipatory trip on loss of main feedwater pump control oil pressure or high RCS pressure due to reduced primary to secondary heat transfer. Upon reactor trip, the operators immediately implement the EOP's which require them to constantly monitor for three main symptoms of off-normal conditions:

a) Lack of subcooling

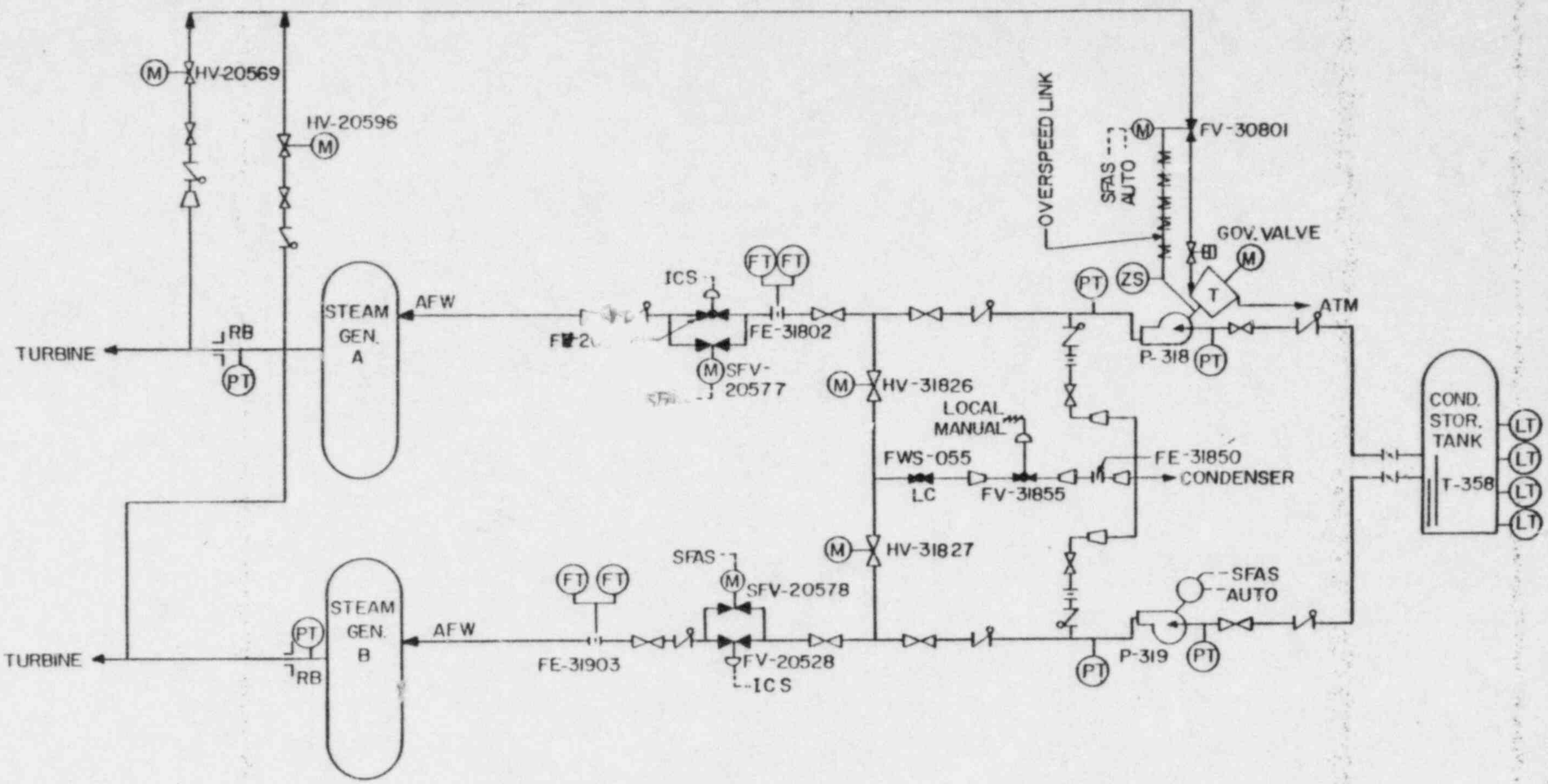
b) Lack of primary to secondary heat transfer (overheating)

c) Excessive primary to secondary heat transfer (overcooling)

Rapid identification of loss of main feedwater (overcooling) will occur because there are numerous alarms and indicators which will alert the operator. The operators receive extensive simulator training in recognizing the three main off-normal symptoms. Among the main annunciator audible alarms and other indicators are MFP discharge pressure low alarm, MFP low flow alarm, MFP trip alarm, MFP zero speed alarm, SPDS post trip RCS pressure temperature display, MFP control panel indication of MFP turbine trip, speed, turbine governor valve position, and panel indication of feedwater flow and OTSG levels.

The EOP for overheating gives specific direction to establish feedwater to the OTSG's using AFW. Additionally the abnormal operation procedure for AFW directs the operator to use the SFAS control valves whenever ICS control is unavailable or undesirable.

FIGURE B



RANCHO SECO
AUX. FEEDWATER SYSTEM
OCT. 1985

ATTACHMENT 6

AUXILIARY FEEDWATER PUMP SURVEILLANCE TESTING

Based on reconsideration of the guidance provided in Generic Letter 83-37, the District has concluded that the Rancho Seco Technical Specifications relating to Auxiliary Feedwater would be improved by incorporation of the sample Auxiliary Feedwater Technical Specifications contained in Enclosure 3 of the letter.

Within 60 days, the District will submit an amendment to the Technical Specifications that will incorporate these portions of the generic letter.

For the past six years, plant procedures have required that an operator, in constant communication with the control room, be stationed at the manual test line isolation valve when it is open.

The frequency for surveillance testing of the auxiliary feedwater pumps has been increased from quarterly to monthly.

Between now and when the new Technical Specifications are approved, the plant will be operated as if the sample specifications of Generic Letter 83-37 apply in cases where they are more conservative than the present Rancho Seco Technical Specifications.

ATTACHMENT 7

REVIEW OF OPERATING PROCEDURES

The Emergency Operating Procedures were reviewed in light of the October 2, 1985, event and were determined to be appropriate and correct. It was noted, however, that an improvement could be made to the excessive heat transfer procedure to more rapidly terminate the overcooling should feedwater valves fail to close upon demand. This change requires feedwater pump trip should closure command to the feedwater valves fail to terminate feedwater flow. The procedure was originally correct and adequate in that it called for OTSG isolation by closing the feedwater valves. However, it did not include the contingency for feed pump trip should the valves fail to close.

Step 3.1 requires a MFP trip if OTSG levels exceed 95%. High OTSG levels during overcooling will occur during overfeed events, not during oversteaming events, and it is for the case of overfeed that this step is in the procedure. The purpose of the step is to prevent OTSG overfill and comes before the steps which close feedwater valves because overfill could be rapid and could require main feedwater pump trip to terminate overfill in a timely manner.

Attachments 8 and 10 will be submitted on Monday, October 28, 1985.

ATTACHMENT 9

NSCW PUMP SURVEILLANCE FAILURE

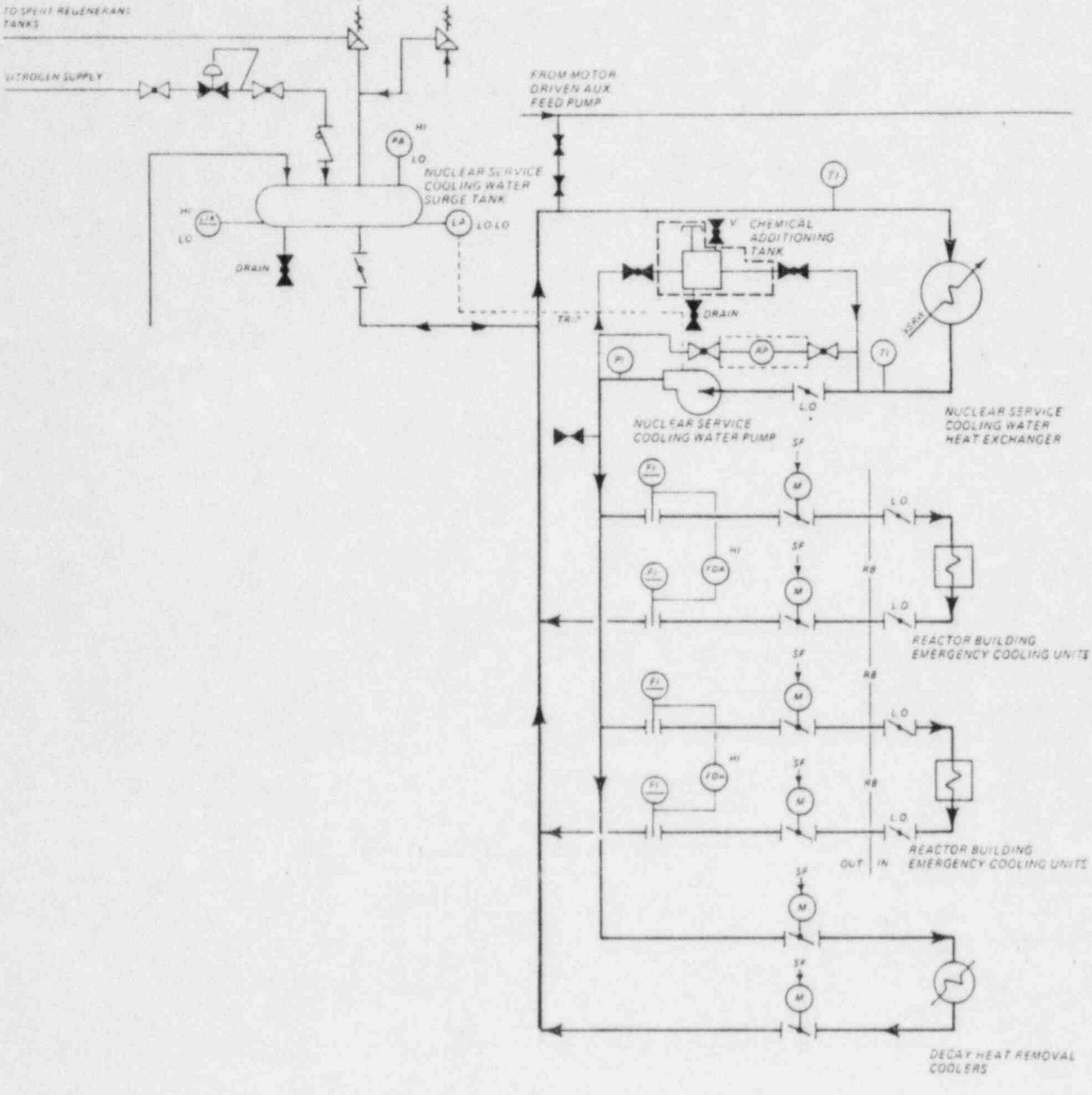
The Nuclear Service Cooling Water (NSCW) System removes heat from the decay heat removal coolers and the reactor building emergency cooling units during post-accident (LOCA) conditions. The NSCW System then transfers this heat to the Nuclear Service Raw Water (NSRW) System. During a normal plant shutdown, the NSCW System removes reactor decay heat from the decay heat removal coolers and transfers that decay heat to the NSRW System. System configuration is shown on the attached figure.

During the refueling outage in May of this year, the flow through the "A" loop of the NSCW system was adjusted to clear high flow alarms on the system. This was accomplished by repositioning the outlet valves on each Reactor Building Emergency cooler. The redistribution of flow throughout the system resulted in a slight increase in pump differential pressure and a corresponding reduction in total system flow as determined by the pump curve.

The surveillance testing done in June prior to plant restart, produced a pump differential pressure in the alert range, as defined by Section XI of the ASME Code. The frequency of the testing was doubled. The results remained consistent until the test on October 23rd when test results indicated a slightly higher differential pressure, on the order of 1%. The pump and valve inservice inspection program required that corrective action be taken.

The cooler outlet valves have been adjusted to increase flow, and a successful pump surveillance test was completed on October 24th. The present flow rate of 6200 GPM is consistent with that measured prior to May and greater than the minimum design rate of 6000 GPM.

The flow in the "B" loop of the NSCW System has repeatedly been substantiated to be acceptable by surveillance testing.



TO SPENT REGENERANT TANKS
NITROGEN SUPPLY
FROM MOTOR DRIVEN AUX FEED PUMP
NUCLEAR SERVICE COOLING WATER SURGE TANK
DRAIN
CHEMICAL ADDITIONING TANK
TRIP
NUCLEAR SERVICE COOLING WATER PUMP
NUCLEAR SERVICE COOLING WATER HEAT EXCHANGER
REACTOR BUILDING EMERGENCY COOLING UNITS
REACTOR BUILDING EMERGENCY COOLING UNITS
OUT
IN
DECAY HEAT REMOVAL COOLERS

ATTACHMENT 11

VALVE CONFIGURATION WALKDOWN

The Rancho Seco Operations Department has conducted walkdowns of selected systems to verify valve configurations. These walkdowns included assuring that valves required in the procedures are tagged and identified. The P&ID's were compared for correctness and any discrepancies were dispositioned by a nonconformance report. Other than the valve on the MSR that initiated this effort, the walkdown team found only one nonconforming valve, associated with a steam trap, that could affect system function.

The systems which were walked down were secondary systems and their support systems which could affect the operation of the OTSG's, such as feedwater, condensate, plant air, auxiliary steam, etc. The 16 systems walked down included approximately 10,000 items assigned plant identification numbers, of which a large portion are valves. A total of 116 valves were found which were not in the procedures nor on the P&ID's. Of these valves, only one, if mispositioned, could have adversely affected system function without providing indication of the problem which would alert the operator to take corrective action. The one valve was an inlet valve to a steam trap on the main turbine. There would be no indication to the operator that the trap was not in service. A large portion of the remaining 115 valves were instrument root valves, vent and drain valves, and large process line valve bypass valves. It has been District policy not to individually show these valves on the P&ID nor place them on the valve lineups, however in its commitment to excellence, the District has taken advantage of this walkdown effort to change its policy and include these valves on system lineups.

LEGEND: SU = Startup Required
LT = Long Term
PE = Power Escalation
NA = Not Applicable
ST = Short Term

STATUS DATE 10-25-85
TIME 1200

OCTOBER 2, 1985 TRANSIENT

- ACTION LIST -

	DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
I	Post Trip Report	J. Field	SU	In Progress	NA	Initial draft completed. PRC comments to be incorporated
II	Root Cause Analysis	S. Crunk	SU	Completed	NA	Reviewed by Management Review Team. Comments to be incorporated.
III	Aux FW ICS Control					
	a. Verify calibration of appropriate modules.	N. Brock	SU	Completed	104969, 104972 104973, 104974 104975	Completed 10/07/85
	b. Reset of Aux FW Valves on MFWP Reset.	B. Spencer	SU	Completed	NA	Crews were trained.
	c. Revise procedures for III.b.	B. Spencer	SU	Completed	SO-20-85	Temporary change to Operating Procedure A.51 done 10/13/85.
	d. Evaluate design of AFW valve reset on restart of MFW Pump or RCP.	V. Lewis	ST	In Progress	NA	
	1. Revise AFW valve control logic for loss of MFW pumps.	N. Brock	SU	In Progress	R-0196	

ATTACHMENT 12

LEGEND: SU = Startup Required
LT = Long Term
PE = Power Escalation
NA = Not Applicable
ST = Short Term

STATUS DATE 10-25-85
TIME 1200

OCTOBER 2, 1985 TRANSIENT

- ACTION LIST -

	DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
IV	HPI "A" Inject Line flow indication					
	a. Write and perform Special Test Procedure.	J. Field	SU	Completed	STP-180	Results approved. See IV d.
	b. Perform calibration check of FT-23807.	N. Brock	SU	Completed	105228	Completed 10/04/85. Found OK.
	c. Resolve flow anomaly and prepare Summary Report.	J. Field	SU	In Progress	S-5103, S-5150	NCRs require closure.
	d. Write and perform a 2nd Special Test Procedure.	J. Field	SU	Test Performed	STP-184	Reviewing results.
V	Pegging Steam Controls					
	a. Determine adequacy of pegging steam setpoints and FW heater relief valve setpoints.	J. Field	SU	Completed	NA	Nuclear Engineering (S. Rutter) Support
	b. 1. Verify setpoints of 2nd and 4th Point heater shell relief valves.	R. Lawrence	SU	Completed	104541, 104544 104542, 104543 104562, 104563	All setpoints as per Process Standards.
	2. Reset 4th point heater shell reliefs to new setpoint values.	R. Lawrence	SU	Completed	104581, 104583 104582, 104584	Revised setpoint values per V a.

LEGEND: SU = Startup Required
LT = Long Term
PE = Power Escalation
NA = Not Applicable
ST = Short Term

STATUS DATE 10-25-85
TIME 1200

OCTOBER 2, 1985 TRANSIENT

- ACTION LIST -

		DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
V	c.	Verify setpoints of all secondary system relief valves which could cause rapid cooldowns/ other FW heater shell reliefs.	R. Lawrence	PE	Planning		Will require use of hydro assist on valves without recent setpoint history.
	d.	Determine appropriate periodic test program (i.e., either PM or SP Program) and implement same for all secondary relief valves.	R. Lawrence	LT			To be done as part of PM program upgrade.
	e.	Resolve report of MSR Reliefs lifting after Rx/Turbine trip.	J. Field	SU	Completed	NA	Resolved that MSR Reliefs did not lift.
	f.	Establish criteria for process setpoint determination.	V. Lewis	LT			
	g.	Review plant for proper application of criteria.	V. Lewis	LT			
	h.	Add setpoints for FSL-32243, 32244, and 32453 to Process Standards.	R. Colombo	LT			AP.152

LEGEND: SU = Startup Required
LT = Long Term
PE = Power Escalation
NA = Not Applicable
ST = Short Term

STATUS DATE 10-25-85
TIME 1200

OCTOBER 2, 1985 TRANSIENT

- ACTION LIST -

	DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
VI	"A" Main Feedwater Pump seal water and controls					
	a. Repair linkage on controller.	N. Brock	SU	Completed	104965	Completed "immediate" repairs 10/02/85.
				Completed	105378	Proper pin installed.
	b. Check common mode failure possibility on controller linkage.	N. Brock	LT	Reviewing	NA	Looking for common mode relations to VI a.
VII	Main Feed Pump Trip Event					
	a. Perform test to duplicate low vacuum condition.	J. Field	NA	Deleted	NA	Test not required.
	b. Install monitoring instrumentation.	N. Brock	SU	In Progress		"A" Pump instrumented. "B" to be done.
	c. Verify "as built" wiring of "A" FWP trip circuits.	C. Linkhart	SU	Completed	102722	Plant drawings accurately show "as built" configuration.
	d. Check setpoints of trip devices.	N. Brock	PE	Hold	102716, 102721 102718, 103272 102720, 103273	Requires WR 102716 to be closed out.

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		DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
VII	e.	Compile history of FW pump control problems.	N. Brock	ST	Completed	NA	
	f.	Check end play on main shaft of "A" MFW Pump.	R. Lawrence	SU	Completed	102719	Acceptable.
	g.	Obtain LO sample from "A" and "B" MFW Pump and have analysis performed.	R. Lawrence	SU	Completed	103269, 102719	Normal.
	h.	Verify "as built" wiring of "B" FWP trip circuits.	C. Linkhart	SU	Completed	105686	Acceptable; elementaries are correct. S-5119 written.
	i.	Install Trip Circuit Alarm Lights.	C. Linkhart	LT	Preparing ECNs		Requires pump out of service.
VIII		Main Condenser Loss of Vacuum Event					
	a.	Update drawings to reflect "as built" conditions of MSR relief sealing steam.	R. Lawrence	SU	Completed	R-0177	
	b.	Revise procedure(s) to show MSR relief sealing steam valves.	B. Spencer	SU	Completed	NA	Temporary change to Operating Procedure A.49 written.

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		DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
VIII	c.	Determine whether sealing steam procedures are adequate and usable.	B. Spencer	SU	Completed	NA	Temporary change to Operating Procedure A.49 written.
	d.	Review/analyze performance of the gland steam condenser.	J. Field	LT	Holding	NA	Long term item.
	e.	Investigate when/why MSR sealing steam valve was closed.	B. Spencer	SU	Completed	NA	Investigation unable to to ascertain when/why valve was closed.
	f.	Determine whether MSR Relief Sealing Steam System works as designed.	R. Lawrence	LT	Completed	NA	Review shows adequate for restart.
	g.	Initiate WR for rework of leaking MSR relief valve.	R. Lawrence	LT	Schedule	104113	Next refueling.
	h.	Resolve setpoint error of main turbine low vacuum trip.	S. Carmichael	SU	Completed	105116	Reset to proper value.
	i.	Correct/upgrade documentation for maintenance on turbine trip block.	R. Lawrence	LT			

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		DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
VIII	j.	Include placement/ removal of MSR relief valve covers in procedures.	B. Spencer	SU	Completed		Temporary change to Operating Procedure B.3 written.
	k.	Fabricate new MSR relief valve covers.	R. Lawrence	ST	Being Designed		
	l.	Include main turbine trip setpoints in Process Standards.	R. Colombo	ST			
	m.	Develop design improvement to reduce leakage of MSR relief valves.	V. Lewis	LT			
IX		Condensate/FW Oscillation	J. Field	SU	Completed	NA	
X		ICS Tuning					
	a.	Prepare ICS/Feedpump tuning STP.	N. Brock	PE	Completed	STP-657	Approved by PRC 10/17/85.
	b.	Perform tuning as plant conditions permit.	N. Brock	PE	Engineering Required		
	c.	ΔTc Control	N. Brock	LT	Engineering		

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	DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
XI	Valve Identification Program					
	a. Develop list of selected systems for Operations walkdown.	B. Spencer	SU	Completed		To include Operating Procedures A.37, A.49,A.41, A.42, A.50, A.46, A.34, A.38, A.40, A.51, A.47, A.28, A.39, A.53, A.6.
	b. Operations crew to walk down systems to identify valves not on prints.	B. Spencer	SU	Completed		
	c. Prepare NCRs on findings and revise procedures as necessary.	B. Spencer	SU	Completed		NCRs written. Temporary changes to procedures written.
	d. Update drawings and place IDs on valves.	B. Spencer	LT	In Progress		DCNs to be generated.
	e. QA Surveillance	H. Canter	SU	Completed	No's. 492, 488	
XII	"B" Feedwater Line Leak Reactor Building.	R. Lawrence	SU	Completed	104548, 104564 104560, 104572 102095, 104569 104567, S-5090 S-5111, S-5093	Report addressing the cause and the repair done. Material meets applicable code.

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	DESCRIPTION	RESPONSIBILITY	SCHEDULE	STATUS	WR No./NCR/ ETC.	COMMENTS
XIII	P-319 Bearing Failure					
a.	Pump Repair	R. Lawrence	SU	Completed		SP run and passed on 10/10/85.
b.	Maintenance History Cause of Failure/ Corrective Action	R. Lawrence	SU	Completed		Surveillance History and Post Repair Test
c.	QA Surveillance	J. Jewett	SU	Completed	No. 485	
d.	Provide oiling instructions	B. Rausch	SU	Completed	TS 85-1033	To include safety related pumps. How to determine level. How to maintain oil level. Pump specific instructions.
e.	Past practice on LO Level.	B. Spencer	SU	In Progress		
f.	Investigate whether "Normal" level was changed.	R. Lawrence	SU	Completed	HLC 85-067	No level change was made.
g.	48-Hour Endurance Run	J. Field	SU	Completed	STP-181	
h.	Identify all safety related pumps which utilize slinger rings.	R. Lawrence	SU	Completed	NA	

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XIII	i.	Oil level indication for P-318, 319, 482 A and B, and 261 A and B.	V. Lewis	SU	In Progress	S-5120, S-5124 S-5114, S-5115 S-5117, S-5118	NCRs require closeout.
	j.	Root Cause	S. Crunk	SU	Completed		Included as subsection of Item II.
	k.	Inspect rings in pumps which have been previously disassembled.	R. Lawrence	SU	Completed	102096, 102097 102099	
XIV		Loss of Aux Steam Event					
	a.	Prepare Report	M. Nickerson	SU	Completed	TS 85-1021	
	b.	Root Cause	S. Crunk	LT	To be Completed 11/30/85	NA	RC 85-021
	c.	Investigate Aux Boiler Power Supply.	C. Linkhart	SU	Completed	NA	
	d.	I and C analysis of XIV c.	N. Brock	LT	To be Completed 11/15/85		

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XV	Training					
a.	Lessons Learned	F. Thompson	LT	Reviewing	NA	
b.	Training on Item III.b	B. Spencer	SU	Completed	NA	SO 20-85 (Instructions/ Recommendation)
c.	Training on pumps/motor oiling	M. Hieronimus	SU	In Progress	NA	
d.	Training on Item III.d.1.	B. Spencer	SU		NA	Crews to be trained prior to going on shift.
XVI	Procedure Adequacy					
a.	EOPs	D. Comstock	SU	Completed	NA	Rule 4 revised.
b.	Normal Procedures	D. Comstock	LT	In Progress	NA	
c.	Identify operator actions not specifically addressed in procedures.	M. Hieronimus	LT	Active Program	NA	Requires input/feedback from AO's, EA's, etc. Memo to SS of 10-10-85 "Problem Feedback Report."
d.	Monitor operation procedures during SU.	D. Comstock	PE	Prepared	NA	QA surveillance planned. Validation of procedures will be performed.
e.	Evaluate operator performance during the trip.	D. Comstock	SU	Completed	NA	

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XVII	Health Physics/Emergency Plan					
	a. Health Physics aspects.	F. Kellie	SU	Completed	FWK 85-202	No Health Physics impact.
	b. Emergency Plan utilization.	B. Spencer	SU	Completed M. Heironimus to B. Spencer memo	NA	Emergency Plan did not require activation.
XVIII	RCS Overcooling					
	a. Tech Spec Review	R. Colombo	SU	Completed	NA	
	b. B and W Evaluation	J. Field	SU	Completed	NA	B and W letter, SMUD-85-222, dated Oct. 4, 1985, "Structural integrity of Pressure Boundary Components are Suitable for Continued Power Operation.
XIX	Preventive Maintenance Program for Non-safety Related Equipment					
	a. Description of existing program.	R. Lawrence	SU	Completed	NA	
	b. Planned improvements.	R. Lawrence	LT	Requires 11/30/85 response to NRC.	NA	