EXHIBIT

1

TECH. ENGR.

6-15-85 T-9216

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DAVIS-BESSE NUCLEAR POWER STATION - UNIT 1

TEMPORARY MODIFICATION REQUEST

ED 6926

SECTION 1

PROCEDURE TITLE AND NUMBER

Trip Recovery, PP 1102.03.14

REASON FOR CHANGE

The station house power readings are no longer on Sheet 11. Also Standing Order # 20 has been voided and its information incorporated in SP 1107 02

CHANGE

1) Void T-9043

2) Change step 4.19.2 to read

Take station house power readings as listed on Daily Reading Sheet 8. Per SP 1107 02, Station Transformer Auxiliaries System Procedure, step 11.3.1.3, the three KWH meters and the totalizer inputs and outputs must be read as soon as possible (within one-half hour) after a shutdown or trip

IS PROCEDURE REVISION REQUIRED Yes ☑ No ☐ If no, this modification is valid until ______

PREPARED BY Lynn Richter	DATE 5/14/85
APPROVED BY G. Lemmon	DATE 5/14/85
APPROVED BY Lynn Richter	DATE 5/14/85
SUBMITTED BY (Section Head) WOER	DATE 5/20/85
RECOMMENDED BY (SRB Chairman) D. W. Briden	DATE MAY 22 1985
QA APPROVED BY (Manager of Quality Assurance) N/A	DATE -
APPROVED BY (Station Superintendent)	DATE MAY 22 1985

Cl/pr

8507290086 850615
PDR ADOCK 05000346
T PDR

TECH. ENGR.

T-9186

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DAVIS-BESSE NUCLEAR POWER STATION - UNIT 1
TEMPORARY MODIFICATION REQUEST
ED 6926

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1 Shift Sup   3 CTRM File
1 Ops Eng
1 CTRM Bck

SECTION 1

PROCEDURE TITLE AND NUMBER

TRIP RECOVERY   PP 1102.03.14

REASON FOR CHANGE

A commitment was made to the NRC that engineering would walkdown the AFPT steam piping after any operation of the AFPT's.

CHANGE

ADD STEP 21 and 22 to Attachment 7, SFRCS Initiation Recovery Guideline.

__21. Nuclear Facility Engineering has been notified to walkdown the AFPT 1-1 and 1-2 steam piping after any operation of the AFPT's.

__22. Nuclear Facility Engineering has approved the steam piping for AFPT 1-1 and 1-2.

Engineer ______________ Time ________ Date ________

IS PROCEDURE REVISION REQUIRED Yes [ ] No [X] If no, this modification is valid until NRC commitment is lifited.

PREPARED BY [signature]	DATE 5-1-85
APPROVED BY [signature]	DATE 5-1-85
APPROVED BY [signature]	DATE 5/1/85
SUBMITTED BY (Section Head) [signature]	DATE 5/6/85
RECOMMENDED BY (SRB Chairman) D. W. Briden	DATE MAY 8 1985
QA APPROVED BY (Manager of Quality Assurance) N/A	DATE -
APPROVED BY (Station Superintendent) [signature]	DATE MAY 8 1985

Davis-Besse Nuclear Power Station

Unit No. 1

Plant Procedure PP 1102.03

TRIP RECOVERY

NUCLEAR SAFETY RELATED

Record of Approval and Changes

Prepared By Louis Simon, William T. O'Connor — 2/4/76 Date

Submitted By Terry D. Murray, Section Head — 5/2/76 Date

Recommended By Jack Evans, SRB Chairman — 5/17/76 Date

QA Approved N/A, Quality Assurance Director — Date

Approved By Jack Evans, Station Superintendent — 6/7/76 Date

Revision No.	SRB Recommendation	Date	QA Approved	Date	Sta. Supt. Approval	Date
11	[signature]	12/8/83	N/A		T D Murray	12/20/83
12	[signature]	4/11/84	N/A		T. D. Murray/SRQ	4/19/84
					Plant Manager Approval	
13	D. W. Briden	10/16/84	N/A		[signature]	11/9/84
14	[signature]	DEC 12 1984	N/A		[signature]	12/29/84

1. PURPOSE

1.1 Section 4 provides the steps to make the transition from the plant conditions in EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture, to the initial conditions required for Section 5.

1.2 Section 5 provides the steps to take the plant from post trip hot standby conditions to the conditions required for entry into either the plant startup or the plant shutdown and cooldown procedure.

2. PRECAUTIONS AND LIMITATIONS

2.1 RX startup is NOT permitted unless the cause of the RX trip is known and corrected. Attachments 1 and 3 must be completed for every reactor trip. If any Technical Specification Safety Limit (Section 2.0) has been exceeded, operation shall not be resumed until authorized by the Commission as per 10 CFR 50.36 Section C. A review of the Computer Post Trip Review is a useful guide in determining the cause of the RX trip.

2.2 Steam Generator limitations are:

The maximum cooldown rate is 100°F/hr.

When cooling down or depressurizing a steam generator, do "NOT" exceed a differential temperature between the RCS cold leg and the steam generator upper downcomer temperature of 25°F.

The minimum temperature limits of the main and auxiliary feedwater nozzles are 90°F and 40°F, respectively, at hot standby conditions. For filling SG, refer to SG Secondary Fill, Drain, and Layup SP 1106.08. A minimum feedwater temperature of 185°F is recommended at RCS temperatures exceeding 280°F. Max. ΔT between SG downcomer and feedwater temperature is 350°F.

For operation below 5 percent power, the main feedwater nozzles must be supplied with a continuous minimum feedwater flow of $\geq$32 gpm to reduce thermal cycling. SG level must be maintained between 18" and 348" on the startup range level indication when the RCS is in Mode 4 or above.

2.3 The startup feedpump may be operated during the trip recovery provided special requirements outlined in SP 1106.27, Startup Feedpump Operating Procedure, are followed.

2.4 The CRD Safety Group 1 will always be at its upper limit during dilution except during performance of approved physics testing. All subcritical boron concentration changes in the RCS will be verified for each predicted change of 30 ppm boron.

loop or condenser pressure greater than 16.9 inches Hg A or MSIV's less than 90% open) the atmospheric steam vent valves must be used for steam header pressure/RCS cooldown rate control.

2.10 Ensure gland sealing steam and auxiliary steam loads are shifted from the main steam header to the Auxiliary Boiler after reactor shutdown to prevent cooldown of the RCS. With a low decay heat load present high steam usage from the main steam line could reduce steam line pressure and result in high RCS cooldown rates. If Auxiliary Boiler is lost, the main steam reducing station can be used to prevent loss of condenser vacuum but steam usage must be limited.

2.11 During operation with a positive moderator temperature coefficient and with boron concentration greater than 1200 ppm, added caution should be used when changing Tave in order to prevent a Tave transient.

2.12 The RCS (except PZR) temp. and press shall be limited in accordance with the limit lines shown on Figures 1 and 2 PP 1101.01, during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A max heatup or cooldown of 100°F if any one hour period per Technical specifications.

CAUTION: For heatup below 532°F and cooldown below 550°F, in addition to the Tech spec limit of 100°F/hr heatup or cooldown rate a further resistriction is imposed for allowable number of heatup and cooldown cycles considerations. Whenever the rate is greater than 15°F/hr the heatup rate should be trended (trend pen with 100°F/hr grease per line or similar tracking device) <u>OR</u> manually plotted every five minutes. The rate should be maintained less than 1.67°F per minute. If the temperature deviates by more than 15°F from the temperature which would occur at that point in time assuming the rate was maintained at 1.67°F per minute the temperature must be restored to a point between the 100°F per hour heatup line and 15°F limit point by holding and maintaining the RCS tempeature. In addition a DVR must be submitted for documentation to ensure a specific evaluation to determine the impact upon the allowable number of heatup and cooldown cycles is performed. This limit applied to all RCS components (including the PZR). For further guidance refer to Standing Order #23.

3.2 NSSS Plant Limits and Precautions, PP 1101.01

3.3 NSSS Setpoints, PP 1101.02

3.4 EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture

3.5 Operational Chemical Control Limits, PP 1101.04

3.6 Plant Prestartup Check, PP 1102.01 (Prestart Checklist)

3.7 Reactor Coolant System Operating Procedure, SP 1103.00 Series

3.8 Auxiliary System Operating Procedures, SP 1104.00 Series

3.9 Instrumentation and Control Systems Procedures, SP 1104.00 Series

3.10 Steam System Operating Procedures, SP 1106.00 Series

3.11 Electrical System Operating Procedures, SP 1107.00 Series

3.12 AD 1839.00, Station Operations

3.13 USAR Section 6 and 7

3.14 Boron Control, SP 1103.04

3.17 Reactivity Balance Calculation

4. PLANT POST TRIP SUPPLEMENTAL ACTIONS

NOTE: Some steps in this section may not be applicable to the plant conditions for all trips. They should be marked N/A after getting the Shift Supervisor's concurrence. Include a brief explanation of the reason the step is N/A.

_____4.1 If the SFAS has initiated, perform Attachment 6 for SFAS equipment recovery guidelines, in parallel with the remainder of Section 4.

_____4.2 If the SFRCS has initiated for any trip except for loss of four RCP's perform Attachment 7 for SFRCS recovery guidelines, in parallel with the remainder of Section 4.

_____4.3 If all four RCP's are stopped, initiate steps to restart idle RCP's. Refer to SP 1103.06, RC Pump Operating Procedure.

If SFRCS has initiated only on loss of four RCP's the AFW pumps may be shutdown when RC flow is reestablished. Refer to SP 1106.06, Section 7, AFP Operating Procedure.

1. PURPOSE

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For operation below 5 percent power, the main feedwater nozzles must be supplied with a continuous minimum feedwater flow of $\geq$32 gpm to reduce thermal cycling. SG level must be maintained between 18" and 348" on the startup range level indication when the RCS is in Mode 4 or above.

2.3 The startup feedpump may be operated during the trip recovery provided special requirements outlined in SP 1106.27, Startup Feedpump Operating Procedure, are followed.

2.4 The CRD Safety Group 1 will always be at its upper limit during dilution except during performance of approved physics testing. All subcritical boron concentration changes in the RCS will be verified for each predicted change of 30 ppm boron.

(TS 3.4.9) 2.5 The PRZR heatup and cooldown shall NOT exceed 100°F in one hour (1.67°F per min.). The PRZR spray shall not be used if the temperature difference between the PRZR and the spray fluid is greater than 410°F.

2.6 Control Rod Safety Group 1 shall be withdrawn to provide tripable reactivity prior to the addition of positive reactivity from a change in reactor coolant temperature, the motion of the APSR's (Group 8), or motion of the control rods (Groups 5-7). The following exceptions to this may be applied:

2.6.1 The RCS has been borated to the hot standby boron concentration as given in Figure 13 of PP 1101.02, Reactor Operator Curve Book, (or greater) and the unit is being maintained in the hot standby condition (Tave ~530°F).

2.6.2 The RCS has been borated to the cold shutdown boron concentration given in Figure 16 of PP 1101.02 (or greater) and the unit is being cooled down.

2.6.3 Group 1 Control Rods need NOT be withdrawn prior to cooling down from ~550 to 530°F provided the cooldown is within the time to reach equilibrium Xe from Figure 1. This time limit is to assure that xenon worth is sufficient to provide the necessary shutdown margin. If the cooldown is NOT started within 10 hours, the Group 1 Rods should be pulled unless the boron concentration, adjusted for the current xenon worth, is greater than the hot standby boron concentration shown in Figure 13 of PP 1101.02. Note that the boron concentration is mathematically adjusted by adding 100 ppm boron for each 1% ΔK/K of worth of xenon. For example, if boron concentration is 950 ppmB and xenon worth is -2.4% ΔK/K, the adjusted worth would be 950 + 240 = 1190 ppmB.

NOTE: Whenever possible, it is desirable to maintain the safety group 1 at its upper limit as an additional safety margin.

2.7 At least two licensed operators shall be present in the CTRM during recovery from reactor trips.

2.8 Notify the Technical Section after a Reactor Trip so that data from the station computer (that is transferred and stored in a 24 hour rotating file in the DBAB computer) can be printed before the file cycles and the data lost.

2.9 When the condenser is unavailable for steam dump, (circulating water flow less than 100,000 gpm is either circulating water

loop or condenser pressure greater than 16.9 inches Hg A or MSIV's less than 90% open) the atmospheric steam vent valves must be used for steam header pressure/RCS cooldown rate control.

2.10 Ensure gland sealing steam and auxiliary steam loads are shifted from the main steam header to the Auxiliary Boiler after reactor shutdown to prevent cooldown of the RCS. With a low decay heat load present high steam usage from the main steam line could reduce steam line pressure and result in high RCS cooldown rates. If Auxiliary Boiler is lost, the main steam reducing station can be used to prevent loss of condenser vacuum but steam usage must be limited.

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a. A max heatup or cooldown of 100°F if any one hour period per Technical specifications.

CAUTION: For heatup below 532°F and cooldown below 550°F, in addition to the Tech spec limit of 100°F/hr heatup or cooldown rate a further resistriction is imposed for allowable number of heatup and cooldown cycles considerations. Whenever the rate is greater than 15°F/hr the heatup rate should be trended (trend pen with 100°F/hr grease per line or similar tracking device) <u>OR</u> manually plotted every five minutes. The rate should be maintained less than 1.67°F per minute. If the temperature deviates by more than 15°F from the temperature which would occur at that point in time assuming the rate was maintained at 1.67°F per minute the temperature must be restored to a point between the 100°F per hour heatup line and 15°F limit point by holding and maintaining the RCS tempeature. In addition a DVR must be submitted for documentation to ensure a specific evaluation to determine the impact upon the allowable number of heatup and cooldown cycles is performed. This limit applied to all RCS components (including the PZR). For further guidance refer to Standing Order #23.

2.13 Seal injection water flow is required to all reactor coolant pumps when reactor coolant temperature and pressure are above 150°F and 150 psig except when operating in the loss of injection mode.

2.14 The following valves have wedges that may stick in their seats if closed when they are hot and subsequently cooled down:

MU-1A, MU-1B, MU-2B, RC-10, RC-11

To prevent separation of the wedge from the valve stem when a valve is closed hot and then cooled down, perform steps as follows:

1. Exercise the valve once for every 100°F cooldown, or

2. If available, isolate the line with a manual valve and then reopen the Velan valve and continue cooldown in a normal manner.

3. If 1 or 2 above can't be performed, attempt to open the valve manually after cooldown. DO NOT ATTEMPT ANY EXCESSIVE FORCE. If valve does not open manually, contact Maintenance for assistance.

2.15 Nuclear instrumentation operation and intermediate/source range channel overlap should be checked during shutdown. At 5×10^{-10} amps on the intermediate range, the source range detectors are energized. When the intermediate range reaches 10^{-10} amps, the source range indication should be decreasing to provide a minimum of one decade overlap.

2.16 The Rapid Feedwater Reduction (RFR) portion of the ICS will target feedwater flow to above 4% and bias MFPT speed in the increase direction on a RX trip. If a RX trip occurs from low power levels, this system may NOT bring the SG's levels to low level limits in the approximately 2 1/2 minutes as intended. A timer in the system will then release FW valve control to tracking normal ICS demand. The MFPT speed control will remain biased upwards (if MFPT is in Auto). The net result of this control should bring the SG levels down to low level limits, however, it will take longer than if the Rx trip was from a high power level. The RFR is armed if the defeat switch in the ICS (Cab 5, Row 2, Module 8) is on, a MFPT is reset and all four FW control valves are in auto.

3. REFERENCES

(TS) 3.1 Davis-Besse Technical Specifications

3.2 NSSS Plant Limits and Precautions, PP 1101.01

3.3 NSSS Setpoints, PP 1101.02

3.4 EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture

3.5 Operational Chemical Control Limits, PP 1101.04

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3.13 USAR Section 6 and 7

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4. PLANT POST TRIP SUPPLEMENTAL ACTIONS

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_____4.3 If all four RCP's are stopped, initiate steps to restart idle RCP's. Refer to SP 1103.06, RC Pump Operating Procedure.

If SFRCS has initiated only on loss of four RCP's the AFW pumps may be shutdown when RC flow is reestablished. Refer to SP 1106.06, Section 7, AFP Operating Procedure.

NOTE: If a cooldown is expected, only 3 RCP's need to be running.

_____4.4 If the reactor power shows any sign of an increase, initiate boron addition.

_____4.5 Stop all but one of the running Condensate Pumps as condensate system flow allows.

_____4.6 When S.G. levels reach 35" or when the rapid feedwater reduction 2.5 minute timer completes its cycle, verify the ICS controls at low level limits or take manual control of the feedwater system.

RFR may need to be defeated by going to off or RFR switch in ICS cabinet, Cabinet 5, Row 2, Module 8.

_____4.7 If both MFP's are running, stop one of the running MFP's.

_____4.8 After the generator field circuit breaker trips, open the exciter field circuit breaker.

_____4.9 <u>WHEN</u> <u>BOTH</u> of the following conditions are indicated:

_____1. Tave within the post trip range of 550° to 555°F, <u>OR</u> stabilized outside the post trip normal range.

<u>AND</u>

_____2. Control of pressurizer level and RCS pressure has been recovered.

<u>THEN</u> perform the following steps:

_____1. Set pressurizer level setpoint at present pressurizer level.

_____2. Return letdown to service.

_____3. Shift MU pump suction back to MU tank if transferred.

_____4. Stop the second MU pump.

_____5. Maintain MU tank level between 55" and 87" by batch additions equivalent to the present RCS boron concentration.

_____4.10 Verify that the turbine bypass valves are attempting to maintain 1015 psig. If not, take manual control of turbine bypass valves. Pressure is controlled by the individual Steam Generator Outlet pressure if the turbine stop valves are closed.

NOTE: If one or more Main Steam Safety Valves/Atmospheric Vent Valves continue to relieve with SG pressure less than 1015 psig, or if all the TBPV's remain closed immediately following a trip, lower the TBPV's setpoint to get on TBPV control and reset Main Steam Safety Valves/Atmospheric Vent Valves. After a reactor trip, a + 145 psi bias will be added to the setpoint on the controller. Pay close attention to the SG levels and the pressurizer level during this process.

_____4.11 Perform the following at the turbine control console (C5713).

1. Start the following pumps before they are started automatically.

   a) Motor Suction Pump with the T-G MSP Control Switch (HIS-2400).

   b) Turning Gear Oil Pump with the TGOP Control Switch (HIS-2401).

14 _____4.12 Ensure that the steam seals remain on the turbine as long as vacuum exists in the condenser. The steam seal header pressure should be 2.5 to 4.5 psig as read on the TURB STM SEAL HDR PRESS Indicator (PI-2340) located on the MSR and Heater Drains Panel (C5722). If the turbine steam seals are lost, immediately open the condenser vacuum breakers by using COND VACM BRKR (HIS-634) located on the Feedwater Panel (C5721).

NOTE: Do NOT break vacuum, except during emergency conditions, until the unit is below its critical speed (900 - 1200 RPM). Examples of emergency conditions are loss of steam seals, loss of lube oil, etc.

_____4.13 Perform Attachment 4 for equipment on the Feedwater Panel (C5721) and the MSR and Heater Drain Tank Panel (C5722).

_____4.14 Perform Attachment 5 for the feedwater heater and deaerator extraction steam non-return valves.

_____4.15 Assign an Equipment/Auxiliary Operator to monitor turbine lube oil temperature. As the turbine speed decreases, the bearing oil temperature should be reduced so that it's 80° to 90°F when rotation stops.

_____4.16 Verify that the source range nuclear instrumentation is activated when the intermediate range nuclear instrumentation indicates 5 x 10^{-10} amps.

_____4.17 Enter in the Operator's Log the last available criticality

information including time, rod position, boron concentration, power level, and RCS average temperature.

_____4.18 When the reactor decay heat load has reduced enough that the feedwater requirements are within the range of the SUFP, place the SUFP in service and the running MFP in standby. Refer to SP 1106.27 for placing SUFP in service.

_____4.19 Restore the 345 KV switchyard to the ring bus configuration.

_____1. Request that the Load Dispatcher open ABS 34620.

_____2. Take station house power readings for Daily Reading Sheet 11 AND for Standing Order 20.

_____3. Dispatch an operator to pull close fuses for ABS 34620 if requested by Load Dispatcher.

_____4. Open the disconnect on TD3 B03-94 AMXG Generator Anti-Motoring to allow a ring bus with the turbine tripped.

_____5. Reset generator XFMR lockout with Load Dispatcher concurrence. Do NOT reset any lockout other than 86-1A (2A) (3A) (4A) GX until the cause of the lockout has been determined and load dispatcher concurrence.

Verify ABS 34620 is open, reestablish a ring bus by closing the generator breakers.

_____ACB 34560 closed
_____ACB 34561 closed

_____4.20 Shift RIM 600 and RIM 609 (MS Line Radiation Monitors) from the analyze mode to the gross mode.

NOTE: When the Rx is shutdown there will be no N-16 gamma present in the RCS, so the MS Line Rad Monitors must be in the gross mode in order to provide early detection of an OTSG Tube Leak.

_____4.21 Instruct C&HP to take a sample of the letdown water between 2 and 6 hours after the trip (per T.S. Table 4.4-4). An isotopic analysis for iodine must be performed (per T.S. Table 4.4-4) and if possible, a gross activity determination should also be performed.

_____4.22 Perform Section 7.2, Shutdown After a Turbine Trip From Power, of SP 1106.15, Moisture Separator Reheater Operating Procedure.

_____4.23 At least two (2) licensed Reactor Operators must be present in the Control Room and at least one licensed Senior Reactor Operator must be present at this unit.

NOTE: The SRO License may be one of the two individuals in the Control Room.

_____4.24 Proceed with Section 5.

5. STABILIZING THE PLANT AT HOT STANDBY CONDITIONS AND INCREASING THE SG LEVELS

NOTE: Some steps in this section may NOT be applicable to the plant conditions for all trips. They should be marked N/A after getting the Shift Supervisor's concurrence.

NOTE: Exact sequence NOT required except for Steps 5.9 through 5.16 which must be done in the sequence listed.

Normally conditions will be as follows:

4 RCP's on
RCS pressure controlled at 2155 psi
PRZR level 100" to 200"
Turbine header pressure being controlled at 1015 psig
Tavg approximately 548°F to 555°F
(This will vary if the trip was from <25% FP)
MU tank level ≥55"
SG's on low level limits
Investigation of the cause of RX trip initiated
Startup Transformers supplying house power
GE Air Dump has closed FW Htr Extraction Non-return valves and opened extraction line drains
One MFPT or SUFP is in operation
Both Htr Drain Pumps are off
Motor Suction Pump, TGOP and Lift Pumps are on
Generator Field Circuit breaker open
One Condensate Pump on

5.1 Place the auxiliary boiler in service per SP 1106.04, Auxiliary Boiler Operating Procedure. Continue with this procedure as the auxiliary boiler is being placed on. When auxiliary boiler is on perform substeps below.

_____1. Transfer Auxiliary Steam Loads to the aux boiler per SP 1106.25, Section 7, Auxiliary Steam System Procedure. Ensure trap header and flash tank vent is shifted.

_____2. Shutdown the flash tank pumps locally.

____3. Slowly increase pegging steam to the main deaerators to maintain ~ 2.5 psig steam blanket on deaerator.

____4. Establish a drain path from the deaerators to the condenser by opening FW 104 and throttling FW 33 to maintain enough condensate flow to prevent water hammer in the deaerator and connecting lines. Keep the flow low enough to prevent exceeding auxiliary boiler capacity for pegging the deaerator.

____5.2 If a MFP is still supplying feedwater, when RX decay heat load has reduced the SG feed requirements to within the range of the SUFP, place the SUFP in service and place the MFP in standby. Refer to SP 1106.27 for placing the SUFP in service.

5.3 Shift the gland seal steam supply from the main steam header to the auxiliary steam header by performing the following from CTRM Panel C5722:

____1. Open the auxiliary steam supply to Gland Steam System drain valve, AS 1934, using HIS 1934.

____2. Open the auxiliary steam supply to Gland Steam System, GS 2380, using HIS 2380.

____3. Close main steam supply to Gland Steam System, GS 2384, using HIS 2384.

____4. Close auxiliary steam supply to Gland Steam System Drain Valve AS 1934.

5.4 When the turbine has come to rest (approximately 90 minutes with Vacuum), perform the following.

____1. Verify the turbine is on gear.

____2. Lockout the Motor Suction pump.

____3. If the shutdown is expected to last more than 24 hours, activate blanketing steam per SP 1106.15, MSR procedure.

____4. Shift H_2 purity analyzer to vent and verify flow is 1 scfm.

____5. Verify lube oil temperature is 80°F.

____6. With the generator at rest or on turning gear, there is no positive ventilation of the exciter house. EITHER degas the generator as a safety measure during long duration outages OR have temporary fans installed to ventilate the

exciter house AND have daily checks made for Hydrogen leakage into the exciter house. Contact the Operations Engineer for guidance.

_____5.5 Check the EHC first hit panel to determine the cause of the turbine trip.

CAUTION: Never reset the EHC trip system before the cause of the trip has been clearly established and the responsible malfunction has been corrected.

_____5.6 Verify both OTSG's on low level limits and place Steam Generator/RX Demand, and RX Demand ICS Stations in hand and run down to minimum.

_____5.6.1 Place ΔTc controller in manual set demand @ 50%.

_____5.6.2 Place both feedwater loop demands to zero. AND verify feedwater flow remains constant.

_____5.6.3 The operating MFP may be put in manual as needed to prevent OTSG level oscillations.

5.7 Determine from Boron Concentration Control Procedure, SP 1103.04, the feed solutions required to maintain RCS Boron Concentration at its' present value (from primary plant status board and boronometer) while adding the contraction volume required during RCS cooldown to 530°F.

_____5.7.1 Maintain PZR Level @ 100 inches if a Rx startup is planned. If a cooldown is expected, maintain PZR level @ 200 inches. Any volume above the 100" level required for plant startup can be used as contraction volume during the cooldown from post trip Tave to 530°F.

_____5.7.2 Increase MU tank level to 86". Record the batch sizes and sources below.

B_1__________gal B_2__________gal
from________ from________

_____5.8 If a cooldown is planned, begin degasing per SP 1102.12, Hydrogen Addition and Degasification Procedure to the limits given in SP 1102.12.

_____5.9 In preparation for withdrawing CRA Safety Rod Group 1, reset ARTS and then RPS as follows:

NOTE: If the control rods cannot be withdrawn or if the RPS and/or ARTS cannot be reset at this time, refer to Step 2.6.3.

To reset ARTS, perform the following steps at each channel:

_____1. Obtain keys to the ARTS cabinet from the Shift Supervisor.

_____2. If both MFPT's are tripped, obtain the four test trip bypass switch (TTBS) keys from the Shift Supervisor for all four ARTS channels. Place all four TTBS in the MFP position to block the trip signal from the ARTS to the RPS.

_____3. Verify the 1/5 lights are off.

_____4. Press the reset button and verify the TRIP light goes off.

To reset the RPS, perform the following steps at each channel when the conditions causing the trip have cleared.

_____5. Obtain keys to the RPS Cabinet from the Shift Supervisor.

_____6. Reset the appropriate trip bistables and output memory bistables for the parameter(s) that caused the RX trip by depressing the "Reset" toggle switch.

_____7. Reset the Reactor Trip Module (location 2-2-7) by depressing the "Reset" toggle switch on the Reactor Trip Module. The "Channel Trip" lamp should go dim.

_____8. Reset the"Output Memory" lamp on the Source Range SUR Bypass/High Voltage Shutoff from NI-3 (NI-4) Bistable (Channel 3 and 4; location 1-2-9).

_____9. Reset the "Output Memory" lamp on the Flux 10% Bistable (Channel 1 and 2: location 1-7-12: Channel 3 and 4, location 1-8-12).

_____10. Close and lock RPS Cabinet doors and return keys to the Shift Supervisor.

_____Channel 1 _____Channel 2 _____Channel 3 _____Channel 4

_____5.10 Verify component cooling water flow of at least 122 GPM supplied to CRDMs.

CAUTION: Prior to resetting the Control Rod Drive System, ensure the Turbine Bypass Valve H/A stations are in hand, ICS 12A & B, as the +145 psi bias will be removed from their setpoint.

_____5.11 After verifying the TBV H/A stations are manual, reset the Control Rod System, latch safety rod groups 1 through 4, reset the Relative Position indication and withdraw safety group 1 as per Control Rod System Procedure, SP 1105.09, Section 4.1.

NOTE: Observe count rate while withdrawing control rods.

_____5.12 Using either the turbine bypass valves (PIC ICS 12A & B) in manual or the turbine header pressure controller setpoint (PIC ICS 10), slowly reduce turbine header pressure to 870 psig.

NOTE: Step 5.14 can be performed at the same time as this step for a smoother cooldown to 530°F.

_____5.13 Monitor RCS temperature and pressure during cooldown to verify TS 4.4.9.1.1. while cooling down; log the time and pressure and temperature every 1/2 hr during cooldown in the RO Log.

_____5.14 As turbine header pressure is lowered (and SG level increased if Step 5.16 is done at the same time as this step), RCS temperature will decrease from approximately 546°F. Add borated water per Boron Concentration Control Procedure, SP 1103.04, to maintain Makeup Tank level at 55 inches if necessary.

_____5.15 Place the turbine bypass valve ICS station in Auto (PIC ICS 12A and B), with the header pressure setpoint at 870 psig (45%) on PIC ICS 10.

_____5.16 Place the Main Feedwater and Startup Feedwater Control Valves (FIC ICS 35A & B and FIC ICS 33A & B) in hand control and slightly increase feedwater flow to both SG's. Minimize the amount of cooldown to the reactor coolant system unless this step is being performed at the same time as header pressure is being reduced. Increase the SG's level to 250 ± 50" on the startup range.

NOTE 1: This step may be performed with Step 5.14.

2. If reactor startup is expected within ~10 hours, it is permissible to remain on low level limit control with Feedwater Valves in AUTO. If the return to power is delayed or if necessary to improve Steam Generator chemistry, S/G levels should be increased to 250 ± 50".

_____5.17 If possible, perform an inspection of containment at full temperature and pressure. This inspection will identify leaks and other potential problems. If a cooldown is planned, this inspection is highly desirable. As a minimum the inspection should include the pressurizer valve room, the top and bottom of <u>BOTH</u> "D" rings, the Letdown Cooler area, the incore closure seals and the Decay Heat Valve pit area. The inspection should be made by a team consisting of representatives from Operations, Maintenance and Chemistry and Health Physics. The list of identified problems should be turned in to each department's supervisor.

_____5.18 Update the Shift Supervisor status board for the due date and time for ST 5061.05.

_____5.19 If the water in the Steam Generators is out of spec, start the following sequence: fill, soak (approximately two hours), and drain Steam Generators. Continue this procedure until the water in the SG's is within spec. If the chemistry is out of limits after eight hours, the system must be cooled to less than 400°F.

LIMITS:	Cl	1.0 ppm max
	Sodium	2.0 ppm max
	Cation Conductivity	10.0 μmho/cm
	Silica	2.0 ppm max

_____5.20 If the time since the reactor trip approaches the time required to reach equilibrium xenon (from Figure 1), a determination should be made as to whether or not the plant is to be cooled down. This is required to assure a 1% shutdown margin after the trip.

1. If a cooldown is <u>NOT</u> expected, <u>THEN</u>

   borate the RCS to the value given in Figure 13 of PP 1101.02

   <u>OR</u>

   If it desired to have a boron concentration below the value given in Figure 13 (for a quick restart), obtain an Estimated Critical Boron (ECB) calibration from the START program and maintain the RCS boron concentration equal to or about the boron concentration given in the ECB calculation for that hour. When all the Xenon decays, the ECB boron concentration value will be equal to the value given in Figure 13.

   NOTE: If an adjusted boron concentration is used, put an information Tag near the batch controller indicating how long the boron concentration is good for.

2. <u>IF</u> a cooldown is expected, <u>THEN</u>

   borate the RCS to the value given in Figure 15 of PP 1101.02.

   NOTE: If Figure 15 is used, put an Information Tag on the Diamond T-handle indicating that the boron concentration only allows CRA Group 1 to be pulled and still maintain the reactor 1% $\Delta k/k$ shutdown (1% $\Delta k/k$ <u>SHUTDOWN VALUE</u>).

_____5.21 Complete Attachment 3, Post Trip Review.

_____5.22 If plant cooldown is expected, de-energize the generator core monitor as per Generator, SP 1106.09.

_____5.23 If plant cooldown is planned, proceed to Plant Shutdown and Cooldown Procedure, PP 1102.10, Section 5 (Cooldown of NSSS from Hot Standby Condition).

_____5.24 If it is desired to return the reactor to power from the reactor trip, complete Attachment 1, Checklist for Return to Power Following a Reactor Trip. Then proceed to Plant Startup Procedure, PP 1102.02, Section 7, with the exception that the MODE 2 and MODE 1 checklist need not be completed. Successful completion of the Checklist for Return to Power Following a Reactor Trip will satisfy MODE 2 and 1 requirements.

At the completion of this section the following conditions should normally exist.

- RCS pressure 2155 PSIG
- T_{ave} approximately 532°F
- Pressurizer level 100 inches. If return to power, 200" if cooldown planned
- RCP combination 2/2
- RCS boron concentration as necessary to maintain the reactor greater than 1% $\Delta K/K$ subcritical
- Group 1 Rod fully withdraw, Groups 2 through 7 fully inserted, and Group 8 at its previous position
- Normal Letdown in Service
- Main feedpump or startup feedpump in service
- OTSG level maintained at 35 to 70% or at low level limits
- Decay Heat being removed by dumping steam to the condenser
- Deaerator pegging steam heating feedwater
- Auxiliary boiler supplying Auxiliary Steam

Section 5 completed by______________________________Date__________

Checklist for Return to Power Following a Reactor Trip

The following checklist must be completed for each reactor trip from power prior to restart.

_____1. Attachment III, "Post Trip Review" has been completed or an SRB review of the trip has been performed.

2. Without actually filling out the checklist, look through Mode 2 and Mode 1 Startup Checklists in PP 1102.01, Prestartup Checklist. Verify the status of these systems is in a condition such that a startup can be made.

NOTE: Refer to TS Table 4.3-1 for RPS surveillance requirements. Items 1, 10, 11, and 12 are required prior to each startup. Items 1, 10, 11 and 12 have a "Note 1," if not performed in previous 7 days.

Notify the I&C Engineer or the I&C Shop Foreman that the following Surveillance Tests must be completed prior to plant startup:

_____2.1 ST 5030.02 (Intermediate Range Only) must be done if required by the ST schedule.

_____2.2 ST 5030.17 (Intermediate Range Prestartup Functional Test) if not performed within previous 7 days.

_____2.3 ST 5091.01 (Channels 1 and 2, Source Range) if not performed within previous 7 days.

_____2.4 ST 5030.12 (Functional Test of the Reactor Trip Module Logic and Control Rod Drive Trip Breakers) if not performed within previous 7 days.

Operations personnel are to perform the following:

_____2.5 ST 5030.13 (Functional Test of Manual Reactor Trip) if not performed within previous 7 days.

_____2.6 ST 5073.01 (MSIV Valve Test) if not performed within previous 92 days.

_____2.7 ST 5013.04 (CRD exercising monthly) should be performed during rod withdrawal for startup.

_____3. Verify the unit is not in an ACTION statement of Technical Specifications which now would prevent re-entry into MODES 2 and 1.

NOTE: If 1, 2, or 3 cannot be verified, stop at this point in the checklist since the return to power cannot be made.

____4. Contact maintenance to replace canvas hoods on any main steam safety valves that may have lifted on the trip.

____5. If the Operations Engineer and the Technical Engineer have concurred to extend the 24 hour limit on this checklist, so document this extension by filling in the time allowed in addition to the original 24 hours. If no concurrence was given, place N/A in the blank.

Operations Engineer Notified By________________Date__________

Extension________Hours

Technical Engineer Notified By_________________Date__________

Extension________Hours

____6. At least two (2) licensed Reactor Operators must be present in the Cotnrol Room and at least one licensed Senior Reactor Operator must be present at this unit.

NOTE: The SRO License may be one of the two individuals in the Control Room.

Shift Supervisor_____________________Date__________

____7. The Operations Engineer (or his designee) and the Plant Manager (or his designee) have given permission for restart.

Plant Manager Notified By______________________Date__________

Operations Engineer Notified By________________Date__________

This form should be routed to the Operations Engineer for his review.

Reviewed By Operations Engineer_________________________Date__________

After the Operations Engineer completes his review, the completed form should be routed to the Technical Section for filing into the unit trip files.

Checklist completed: Shift Supervisor__________________Date__________

Isolation of Main Steam Line Drains and Loads to Permit Pressure Equalization for Opening MSIV's

	Isolated By	Restored By
Main Steam Line No. 1 (MS 101)		
Located 623' Aux. Bldg.		
Isolate ST 39, MS 106		
Isolate ST 132, by 107A		
Located 603' Turb. Bldg.		
Close MS 710, MS Line 1 TBV Iso		
Close MS 710A, MS Line 1 TBV Iso Bypass		
Close MS 1299B or MS 846, w/u Line		
Located 585' Turb. Bldg.		
Close MS 706, MS Line 1 to MFPT 1-1		
Isolate ST 66, by MS 706		
Close MS 708, MS to AS Red. Sta.		
Close MS 2582, 2nd Stage R.H. S/U Drain		
Isolate ST 101, M.S. Line 1 Drain Trap		
Close MS 266 or MS 847, ST 101 Bypass		

NOTE: MS 101 may be opened when ΔP across the valve is less than 250 psid. Restore all valves and traps to normal S/U position as soon as possible after opening MS 101.

	Isolated By	Restored By
Main Steam Line No. 2 (MS 100)		
Located 623' Aux. Bldg.		
Isolate ST 125, by MS 107		
Isolate ST 121, by MS 106A		
Located 603' Turb. Bldg.		
Close MS 709, MS Line 2 TBV Iso		
Close MS 709A, MS Line 2 TBV Iso Bypass		
Close MS 840, MS to SG Iso		
Close MS 1299A or MS 843, MS Line 2 w/u Line		
Located 585' Turb. Bldg.		
Close MS 707, MS Line 2 to MFPT 1-2		
Isolate ST 67, by MS 707		
Isolate ST 100, MS Line 2 Drain Trap		
Close MS 138 or MS 841, ST 100 Bypass		

NOTE: MS 100 may be opened when ΔP across the valve is less than 250 psid. Restore all valves and traps to normal S/U position as soon as possible after opening MS 100.

Post Trip Review

The following review must be completed for each reactor trip (except normal tripping of CRD during heatups and cooldowns) even if a unit restart is not in progress.

1.1 Plant Pre-Trip Conditions (to be completed by the Shift Technical Advisor and Operations personnel after the plant stabilization is complete).

(A) Reactor power prior to the trip: _________%

Note any runback that occurred: ______________________________

____

____

(B) List any ICS stations in manual prior to the trip: __________

____

____

(C) List any testing in progress prior to the trip: ____________

____

____

(D) List any safety systems inoperable prior to the trip:

____

____

(E) List any other abnormal plant conditions contributing to the plant trip (inoperable main feedwater pump, high condenser vacuum, etc.).

____

____

Completed By______________________________________Date__________

1.2 Plant Post Trip Conditions (to be completed by the Shift Technical Advisor and Shift Supervisor after the plant stabilization is complete).

(A) Did any of the following occur? (Use Control Room recorders, computer information, or operator observations.)

	No
Did the PORV actuate?	____
Did the pressurizer code safety valves actuate?	____
Did either steam generator level exceed 82.5%?	____
Did SG level go below 18"?	____
Was SFAS actuated?	____
Did pressurizer level decrease below 8 inches?	____
Did pressurizer level exceed 300 inches?	____
Was the Emergency Plan activated?	____
Did the SFRCS actuate?	____

If any of the above did occur, determine the cause and describe below:

____

____

____

____

____

____

____

(B) Write a short description of the cause of the trip, the ractor trip sequence of events which resulted in the trip, and any actions taken to prevent recurrence. (Review the Post Trip Review, Alarm Printout, and Sequence of Events Printouts, if available.)

____

____

____

____

____

____

____

Shift Technical Advisor______________________________Date__________

Shift Supervisor____________________________________Date__________

1.3 Safety Review of Transient (to be completed by Shift Technical Advisor and Shift Supervisor).

(A) Verify no safety concerns* have been identified in the review of the trip.

*A safety concern is defined as a safety related system not performing the design function for which it was intended.

Shift Supervisor________________________________Date__________

Shift Technical Advisor_________________________Date__________

(B) Verify no safety limits exceed during the transient (see Technical Specification 2.1). If any safety limits has been exceeded, operation shall not be resumed until authorized by the Commission as per 10CFR50.36 Section C.

Shift Supervisor________________________________Date__________

Shift Technical Advisor_________________________Date__________

If the cause of the unit trip cannot be determined, or the Sequence of Events for the reactor trip cannot be determined, or any safety concern identified, a unit restart cannot proceed until a Station Review Board review of the transient has been completed.

After this form is completed, it should be routed to the Operations Engineer for his review.

Operations Engineer_____________________________________Date__________

After the Operations Engineer review, his attachment should be routed to the Technical Section to be included in the trip files.

1. Press open for main steam line NRV's.

    __________ HIS 209
    __________ HIS 210

2. Close HPT EXT to MSR 1 and 2 1st stage.

    __________ HIS 197

3. Verify closed or close the following valves:

	VALVE NO.	CONTROL SWITCH NAME	CONTROL SWITCH NO.
_____	ES278	HP FW HTR 1-4 LPT EXT VLV	HIS-278
_____	ES264	HP FW HTR 1-5 HPT EXT VLV	HIS-264
_____	ES377	HP FW HTR 2-4 LPT EXT VLV	HIS-377
_____	ES370	HP FW HTR 2-5 HPT EXT VLV	HIS-370
_____	GS346	LP FW HTR 1-1 SEAL REG VLV	HIS-346
_____	GS957	LP FW HTR 2-1 SEAL REG VLV	HIS-957
_____	AS958	CNDS FLSH TK 1 STM OUT MO/L	*HIS-958

*This switch will also open the Condensate Flash Tank Vent to 5 psig steam header valve (AS3748) if it was <u>NOT</u> automatically opened.

4. Verify open or open the following valves:

	VALVE NO.	CONTROL SWITCH NAME	CONTROL SWITCH NO.
_____	ES308	FW HTR 1-5 & 2-5 HPT EX DR	HIS-308
_____	GS2167	STM SEAL REG DMP TO HP COND	HIS-2167

5. Stop Heater Drain Tank Pumps 1-1 and 1-2 using control switches HIS-318 and HIS-342, respectively.

    __________ HDP 1

    __________ HDP 2

6. Verify open or open the following valves:

	Valve No.	Control Switch Name	Control Switch No.
_____ _____	MS 2844 & MS 2845	MSR 1 MOIS SET IN X AROUND	HIS-2844
_____ _____	RD 2146 & RD 2148	MSR 1 MOIS SET DRN	HIS-2146
_____	MS 2842 & MS 2843	MSR 2 MOIS SET IN X AROUND	HIS-2842

	Valve No.	Control Switch Name	Control Switch No.
_____	RD 2150 & RD 2151	MSR 2 MOIS SEP DRN	HIS-2151
_____	TD 2382	STM LEAD DRN VLV 1	HIS-2382
_____	TD 2383	STM LEAD DRN VLV 2	HIS-2383
_____	TD 2368	STM LEAD DRN VLV 2	HIS-2368
_____	TD 2369	STM LEAD DRN VLV 4	HIS-2369
_____	TD 2381	COMBINED CTRL VLV	HIS-2381
_____	MS 138	MN STM 2 TRAP BYPASS	HIS-138
_____	MS 266	MS 1 STM TRAP	HIS-266
_____	ES 249	LPT 1 EXT TO FW HTR 1-2 DRN	HIS-249
_____	ES 415	LPT 1 EXT TO DEAR HTR 1-3	HIS-415
_____	ES 341	LPT 2 EXT TO FW HTR 2-2	HIS-341
_____	ES 411	LPT 2 EXT TO DEAR HTR 2-3	HIS-411
_____	ES 417	LPT 1 EXT TO FW HTR 1-4	HIS-417
_____	ES 252	HPT EXT TO FW HTR 1-6 DRN	HIS-252
_____	ES 409	LPT 2 EXT TO FW HTR 2-4	HIS-409
_____	ES 413	HPT EXT TO FW HTR 2-6	HIS-413

_____7. Depress the bearing lift pump RESET pushbutton (HS 2404A) and start the six (6) bearing lift pumps with the six BEARING LIFT PUMPS before they are started automatically. Control Switches (#1 HIS-2404; #2, HIS-2405; #3, HIS-2406; #4, HIS-2407; #5, HIS-2408; #6, HIS-2409).

1. Verify that the following valves have automatically closed. This must be done using either the respective computer points or by local verification. If these valves have not closed, close them using the local control switch.

	Valve No.	Computer Pt.	Local Control Switch Name	Local Control Switch No.
____	ES 256	Z517	HPT 1ST EXT T/E NRV, FW HTR 1-6	NV-256A
____	ES 349	Z515	HPT 1ST EXT G/E NRV, FW HTR 2-6	NV-349A
____	ES 298A&B	Z586	DEAER HTR 1-1-3 LP TURB 1-1 EXT	NV-298A
____	ES 9845	N/A	DEAR HTR 1-1-3 LP TURB 1-1 EXT	NV-9845
____	ES 325A&B	Z602	DEAR HTR 1-2-3 LP TURB 1-2 EXT	NV-325A
____	ES 9846	N/A	DEAR HTR 1-2-3 LP TURB 1-2 EXT	NV-9846
____	ES 264	Z493	HP EXT NRV FW HTR 1-1-5	NV-264A
____	ES 377	Z600	LPT 3RD EXT NRV FW HTR 1-2-4	NV-377A
____	ES 278	Z585	LPT 3RD EXT NRV FW HTR 1-1-4	NV-278A
____	ES 370	Z495	HPT EXT NRV FW HTR 1-2-5	NV-370A

SFAS INITIATION RECOVERY GUIDELINE

The purpose of this section is:

- To ensure that the SFAS is in the most relible operational condition at all times.
- To act as a guide for recovery from any incident level after a real or erroneous SFAS actuation.

This section is written strictly as a guide for the operator and is in no way intended to be detailed in actions to be taken. No real detail can be provided since the plant conditions at the time of the incident are in themselves unpredictable. The intent of this procedure is to remind or instruct the operator how to evaluate the incident, what general actions need to be taken, what problems to look for, and what detailed procedures will be needed for recovery from the various situations. The conditions of the reactor, primary and secondary systems, the operator actions during SFAS actuation, and the failure of components or systems during SFAS actuation will also determine the required actions for recovery.

The purpose of the Safety Features Actuation System (SFAS) is to automatically prevent or limit fission product and energy release from the core, to isolate the containment vessel and to initiate the operation of the ESF equipment in the event of a Loss of Coolant Accident (LOCA). To accomplish this purpose, SFAS actuated equipment shall NOT be blocked or overridden except as allowed by EP 1202.01, Specific Rule 4.

Blocking to re-initiate system operations should be avoided when possible. The desired method for re-establishing system operations after an erroneous trip is to reset the SFAS trips first. In this way, any subsequent SFAS trips can actuate the appropriate equipment as needed.

Following a real or erroneous trip of any SFAS incident level, the status of the associated equipment is dependent mainly on the incident level(s) actuated. Therefore, this section is divided into subsections by which incident levels occurred. The subsections are:

1. Incident Level 1 Occurrence
2. Incident Levels 1 and 2 Occurrence
3. Incident Levels 1, 2, and 3 Occurrence
4. Incident Levels 1, 2, 3, and 4 Occurrence

The corrective action steps listed in the sections do not have to be completed in the order given except as noted. In fact, it would be better if the steps listed were divided among personnel on shift at the time to speed their completion.

1. Incident Level 1 Occurrence

   An Incident Level 1 Occurrence will automatically initiate when

high radiation (2 times background at 100% power) is detected by two out of four containment radiation detectors, or by one out of three detectors when one has been declared inoperable and has been placed in the tripped condition.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition or the fault causing the automatic initiation has been determined and corrected.

The trip can be determined to be real or erroneous by comparing all four SFAS channels radiation levels and by noting any unusual RCS conditions which would indicate a leak exists. Containment radiation can also be checked on the wide range indicators on the Post Accident Indicating Panels.

1.1 SFAS Equipment Recovery From Real Initiation

(A) If a real high radiation condition does exist, it is probably indicative of a small RCS leak. Follow AB 1203.29, Small RCS Leaks.

(B) After the unit is shutdown, no specific recovery is required from Incident Level 1. Restore actuated equipment listed on Table 1 as required after approval, but do not open closed containment isolation valves unless required by plant conditions.

1.2 SFAS Equipment Recovery From Erroneous Initiation

(A) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(B) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15 if Step (A) above has been completed.

(C) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(D) Restart the Control Room Ventilation System per SP 1104.14, Section 4, as required.

(E) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4. Steps 4.3.14 through 4.3.16.

(F) Secure the Containment Purge System per SP 1104.21, Section 6; or restart per Section 4 as required.

(G) Restore other SFAS actuated equipment as listed on Table 1 to normal as directed by the Shift Supervisor.

2. Incident Levels 1 and 2 Occurrence

A combined occurrence of Incident Levels 1 and 2 will automatically initiate when primary plant pressure drops to less than 1650 psig or containment vessel pressure raises to greater than 18.4 psia.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

The trip can be determined to be real or erroneous by comparing all four SFAS channels for the parameter which tripped the SFAS as indicated by the annunciators. If RCS pressure has reduced to 1985 psig, the independent RPS pressure transmitters would have tripped the reactor. Also, if enough reactor coolant was released into containment to provide 18.4 psia, radiation levels should have increased and pressurizer water level should have dropped. The Post Accident Indicating Panels also contain indication of containment wide range pressure, water level, and radiation as well as normal sump level, all of which can be used for comparison.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

2.1 SFAS Equipment Recovery From Real Initiation

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products or energy from the core and continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) Return both Emergency Diesel Generators to normal standby conditions per SP 1107.11, "EDG Operating Procedure" if not required for emergency power.

(B) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1105.03, (SFAS), Section 5.

NOTE: Resetting of the SFAS cabinets will not change the status of the actuated equipment.

(C) If the SFAS cabinets have been reset, restore other SFAS actuated equipment as listed on Table 1 to normal. Do not open containment isolation valves unless necessary.

2.2 SFAS Equipment Recovery From Erroneous Incident Levels 1 and 2 Trip

After approval from the Shift Supervisor:

(A) Reset the SFAS cabinets per SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the cabinets until the fault causing the actuation is cleared.

(B) Re-establish letdown when necessary for RCS inventory control.

(C) Stop both HPI Pumps and close all four injection valves HP2A, B, C, and D.

(D) Return both Emergency Diesel Generators to normal standby conditions per SP 1107.11, "EDG Operating Procedure".

(E) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15, if Step (A) above has been completed.

(F) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(G) Re-start the Control Room Ventilation System per SP 1104.14, Section 4, as required.

(H) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4.

(I) Restore the Containment Purge System per SP 1104.21.

(J) Restore other SFAS actuated equipment as listed on Table 1.

(K) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to the "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

3. Incident Levels 1, 2, and 3 Occurrence

A combined occurrence of Incident Levels 1, 2, and 3 will automatically initiate when primary plant pressure drops to 450 psig or containment pressure of 18.4 psia. A comparison of the RCS pressure reading in each SFAS Channel will determine if the trip is from a real incident or from erroneous instrumentation. Also, the RPS has separate RC pressure transmitters that will trip the reactor if RCS pressure drops to 1985 psig. If the event is indeed due to a LOCA, containment pressure and radiation levels would be elevated. The Post Accident Indicating Panels also contain indication of containment wide range pressure, water level, and radiation as well as normal sump level, all of which can be used for comparison.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

3.1 Recovery From Real Incident Levels 1, 2, and 3 Occurrence.

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products, to keep the core cool, and the continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) High pressure injection may be stopped or throttled per the Specific Rules section of EP 1202.01.

(B) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "EDG Operating Procedure" if not required for emergency power.

(C) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1104.03, "SFAS Operating Procedure", Section 5.

(D) If the SFAS is reset, restore other SFAS actuated equipment as listed on Table 1 to normal. Do not open containment isolation valves unless necessary.

3.2 SFAS Recovery From Erroneous Incident Levels 1, 2, and 3 Occurrence

After approval from the Shift Supervisor:

(A) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(B) Re-establish seal injection flow by:

(1) Re-open CC1460 to supply cooling water to the MU Pumps.

(2) Closing the seal injection flow control valve using FIC MU19.

(3) Reopen the RCP seal injection valves MU66C (D, A, B).

(4) Reopen MU19 until a flow of 3-5 GPM per seal is established. Open MU38, MU59C (D, A, B) and slowly establish approximately 32 GPM. Transfer hand/auto station to auto.

(5) Re-establish letdown when required for RCS inventory control.

(C) Stop both HPI Pumps and close all four injection valves HP2A (B, C, D).

(D) Stop both DH Pumps.

(E) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure".

(F) Close CS Valves CS1530 and CS1531.

(G) Restore CCW to normal lineup and close the CCW to DH Coolers outlet valves CC1467 and CC1469.

(H) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15, if Step (A) above has been completed.

(I) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(J) Restart the Control Room Ventilation System per SP 1104.14, Section 4 as required.

(K) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4.

(L) Restore the Containment Purge System per SP 1104.21.

(M) Restore other SFAS actuated equipment as listed on Table 1 to normal.

(N) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to the "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

4. Incident Levels 1, 2, 3, and 4 Occurrence

A combined occurrence of Incident Levels 1, 2, 3, and 4 will automatically initiate when containment pressure increases to 38.4 psia. Since the only real incident that can cause this large increase in containment pressure is a major LOCA, by a quick observation of RCS pressure, pressurizer level, and containment radiation levels, the operator can determine if the incident is real or erroneous. The Post Accident Indicating Panels also contain indication for containment WR pressure which can be checked as a backup.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

If Incident Levels 1 through 4 are due to a real occurrence, the BWST level will drop within a matter of hours to the low level setpoint and the DH and CS Pumps suction will have to be transferred to the emergency sump. Therefore, the recovery from a real Incident Level 1 through 4 occurrence is the same as from an Incident Level 1 through 5 occurrence.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

_____4.1 Recovery From Real Incident Levels 1, 2, 3, and 4 Occurrence

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products, to keep the core cool and the continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) High pressure injection may be stopped or throttled per the Specific Rules section of EP 1202.01.

(B) If containment pressure has returned to below 18.4 psia, shut off both CS Pumps and close CS Isolation Valves CS1530 and CS1531.

(C) Return both EDG to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure" if not required for emergency power.

(D) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1105.03, "SFAS Operating Procedure", Section 5.

(E) If the SFAS has been reset, restore other SFAS actuated equipment as listed on Attachment 1 to normal. Do not open Containment Isolation Valves unless necessary. Do not close the containment emergency sump outlet valves if DH/CS suction is from the emergency sump.

4.2 SFAS Equipment Recovery From Erroneous Incident Levels 1 through 4 Occurrence

Since Incident Level 4 closes the MSIV's, the plant trip is a certainty. The operators efforts must be to stop both CS Pumps from spraying borated water into containment and reestablishing CCW to the containment header.

After approval from the Shift Supervisor:

(A) Push the block pushbuttons by the CS Pump control switch and stop both CS Pumps.

(B) Block and reopen the CCW Isolation Valves CC1407A and B and CC1411 A and B.

(C) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure" Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(D) Clear any SFRCS trips present, open the MSIVs, and reestablish condenser vacuum per Attachment 7.

(E) Stop both HPI Pumps and close all four injection valves HP2A (B, C, D).

(F) Stop both DH Pumps.

(G) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure".

(H) Close CS Injection Valves CS1530 and CS 1531.

(I) Restore CCW to normal lineup and close the CCW to DH Coolers Outlet Valves CC1467 and CC1469.

(J) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be performed as per Step 7.1.1 if Step (C) above has been completed.

(K) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(L) Restart the Control Room Emergency Ventilation System per SP 1104.14, Section 4, as required.

(M) Re-establish ECCS Room Ventilation per SP 1104.16, Section 4.

(N) Restore the Containment Purge System per SP 1104.21.

(O) Restore other SFAS actuated equipment as listed on Table 1 to normal.

(P) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 1

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
C30-1	M-029A	Emer Vent Fan 1	SA 111A	Start	Off
HV 5439	M-028B	ECCS Room 105 HV&AC Iso Vlv	SA 111B	Closed	Open
HV 5440	M-028B	ECCS Room 105 HV&AC Iso Vlv	SA 111C	Closed	Open
HV 5024	M-029A	Emer Vent Fan 1 Vlv from Aux. Bldg.	SA 111D	Closed	Various
HV 5716	M-028B	ECCS Room 115 Iso Dmpr	SA 111E	Closed	Various
C30-2	M-029A	Emer Vent Fan 2	SA 112A	Start	Off
HV 5441	M-028B	ECCS Room 115 HV&AC Iso Vlv	SA 112B	Closed	Open
HV 5442	M-028B	ECCS Room 115 HV&AC Iso Vlv	SA 112C	Closed	Open
HV 5025	M-029A	Emer Vent Fan 2 Vlv from Aux. Bldg.	SA 112D	Closed	Various
HV 5715	M-028B	ECCS Room 105 Iso Dmpr	SA 112E	Closed	Various
CV 5008	M-029A	CTMT Purge Out Iso Vlv	SA 121B	Closed	Closed
CV 5011A	M-029B	CTMT Air Sample Iso Vlv	SA 121C	Closed	Open
CV 5011B	M-029B	CTMT Air Sample Iso Vlv	SA 121D	Closed	Open
CV 5011C	M-029B	CTMT Air Sample Iso Vlv	SA 121E	Closed	Open
CV 5011D	M-029B	CTMT Air Sample Iso Vlv	SA 121F	Closed	Open
CV 5006	M-029A	CTMT Purge In Iso Vlv	SA 121G	Closed	Closed
CV 5009	M-029A	Mech Pent Room 4 Purge Vlv	SA 121H	Closed	Closed
CV 5016	M-029A	Mech Pent Room 4 Purge Vlv	SA 121I	Closed	Closed
CV 5011E	M-029B	CTMT Air Smpl Ret Iso Vlv	SA 121J	Closed	Open
S10-1	M-027A	CTMT Ret Fan & HV/AC Unit 1	SA 121L	Various	

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 1

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
CV 5010D	M-029B	CTMT Air Sample Iso Vlv	SA 122B	Closed	Open
CV 5004	M-029A	Mech Pent Room 3 Purge Vlv	SA 122C	Closed	Closed
CV 5021	M-029A	Mech Pent Room 3 Purge Vlv	SA 122D	Closed	Closed
CV 5005	M-029A	CTMT Purge In Iso Vlv	SA 122E	Closed	Closed
CV 5007	M-029A	CTMT Purge Out Iso Vlv	SA 122F	Closed	Closed
CV 5010A	M-029B	CTMT Air Sample Iso Vlv	SA 122G	Closed	Open
CV 5010B	M-029B	CTMT Air Sample Iso Vlv	SA 122H	Closed	Open
CV 5010C	M-029B	CTMT Air Sample Iso Vlv	SA 122I	Closed	Open
CV 5010E	M-029B	CTMT Air Sample Ret Iso Vlv	SA 122J	Closed	Open
S10-2	M-027A	CTRM Ret Fan & HV/AC Unit 2	SA 122L	Stop	Various

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P58-1	M-033	HP Inj PMP 1	SA 211A	Start	Off
HP2C	M-033	HP Inj 1-1 Vlv	SA 211B	Open	Closed
HP2D	M-033	HP Inj 1-2 Vlv	SA 211C	Open	Closed
P58-2	M-033	HP Inj Pmp 2	SA 212A	Start	Off
HP2A	M-033	HP Inj 1-2 Vlv	SA 212B	Open	Closed
HP2B	M-033	HP Inj 2-2 Vlv	SA 212C	Open	Closed
C 1-1	M-029A	CTMT Clr Fan 1	SA 221A	Start	Various
C 1-3	M-029A	CTMT Clr Fan 3	SA 221B	Slow	Various
C 1-2	M-029A	CTMT Clr Fan 2	SA 222A	Slow	Various
C 1-3	M-029A	CTMT Clr Fan 3	SA 222B	Slow	Various

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P43-1	M-036	CC Pump 1	SA 231A	Start	Various
P43-3	M-036	CC Pump 3	SA 231B	Start	Various
CV 5070	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231C	Closed	Open
CV 5071	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231D	Closed	Open
CV 5072	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231E	Closed	Open
CV 5073	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231F	Closed	Open
CV 5074	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231G	Closed	Open
P43-2	M-036	CC Pump 2	SA 232A	Start	Various
P43-3	M-036	CC Pump 3	SA 232B	Start	Various
CV 5075	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232C	Closed	Open
CV 5076	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232D	Closed	Open
CV 5077	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232E	Closed	Open
CV 5078	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232F	Closed	Open
CV 5079	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232G	Closed	Open
P3-1	M-041	SW Pump 1	SA 241A	Start	Various
P3-3	M-041	SW Pump 3	SA 241B	Start	Various
SW 1424	M-041	SW From CC HX 1 Iso Vlv	SA 241C	Open	Various
SW 1429	M-041	SW From CC HX 3 Iso Vlv	SA 241D	Open	Various
P3-2	M-041	SW Pump 2	SA 242A	Start	Various
P3-3	M-041	SW Pump 3	SA 242B	Start	Various
SW 1434	M-041	SW From CC HX 2 Iso Vlv	SA 242C	Open	Various
SW 1429	M-041	SW From CC HX 3 Iso Vlv	SA 242D	Open	Various
CS 1530	M-034	CS 1 Iso Vlv	SA 251A	Open	Closed
CS 1531	M-034	CS 2 Iso Vlv	SA 252A	Open	Closed
K 5-1	E-3	Emer DG 1	SA 261A	Start	Off
K 5-2	E-3	Emer DG 2	SA 262A	Start	Off

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
MU2A	M-031	RC Letdown Delay Coil Out Vlv	SA 271A	Closed	Open
DR 2012A	M-046	CTMT Norm Sump Iso Vlv	SA 271D	Closed	Open
RC 240A	M-030	RC PRZR Sample Vlv	SA 271E	Closed	Closed
SW 1399	M-041	SW Iso Vlv to Clng Wtr	SA 271F	Closed	Open
RC 1773A	M-040A	RC DT Hdr Iso Vlv	SA 271G	Closed	Open
RC 1719A	M-040A	CTMT Vent Hdr Iso Vlv	SA 271H	Closed	Open
SS 607	M-007	SG 1 Sample Iso Vlv	SA 271I	Closed	Open
ICS 11B	M-007	SG 1 Atm Stm Vent Vlv	SA 271J	Closed	Open
SS 235A	M-040A	Przr Qnch Tk Sample Iso Vlv	SA 271K	Closed	Closed
CF 1544	M-034	CF Tk 1 H_2O and N_2 Fill Iso Vlv	SA 271L	Closed	Closed
MU 3	M-031	RC Letdown Hi Temp Vlv	SA 272A	Closed	Open
DR 2012B	M-046	CTMT Norm Sump Iso Vlv	SA 272C	Closed	Open
RC 240B	M-030	RC Przr Vapor Sample Vlv	SA 272D	Closed	Closed
CF 1542	M-034	CF Tk Vent Iso Vlv	SA 272E	Closed	Closed
SW 1395	M-041	SW Iso Vlv to Clng Wtr	SA 272F	Closed	Closed
RC 1773B	M-040A	RC DT Hdr Iso Vlv	SA 272G	Closed	Open
RC 1719B	M-040A	CTMT Vent Hdr Iso Vlv	SA 272H	Closed	Open
SS 598	M-007	SG 2 Sample Iso Vlv	SA 272I	Closed	Open
ICS 11A	M-007	SG 2 Atm Stm Vent Vlv	SA 272J	Closed	Open
SS 235B	M-040A	PRZR Qnch Tk Sample Iso Vlv	SA 272K	Closed	Closed
CF 1541	M-034	CF Tk 2 H_2O and N_2 Fill Iso Vlv	SA 272L	Closed	Closed
DH 9B	M-033	CTMT Emer Sump Vlv	SA 281A	Closed	Closed
DH 7B	M-033	BWST Out Vlv	SA 281G	Open	Open
NN 236	M-019	N_2 CTMT Iso Vlv	SA 281H	Closed	Open
RC 229A	M-040A	PRZR Qnch Tk Out Iso Vlv	SA 281I	Closed	Open
MS 394	M-003	Mn Stm Line 1 WU Drn Iso Vlv	SA 281J	Closed	Open

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
RC 232	M-040A	PRZR Qnch Tk In Iso Vlv	SA 282A	Closed	Open
RC 229B	M-040A	PRZR Qnch Tk Out Iso Vlv	SA 282B	Closed	Open
CC 1545	M-034	CF Tk Sample Vlv	SA 282D	Closed	Closed
DH 9A	M-033	CTMT Emer Sump Vlv	SA 282E	Closed	Closed
DH 7A	M-033	BWST Out Vlv	SA 282G	Open	Open
IA 2011	M-015	CTMT Instr Air Iso Vlv	SA 282H	Closed	Open
SA 2010	M-015	CTMT Serv Air Iso Vlv	SA 282I	Closed	Open
MS 375	M-003	Mn Stm Line 2 WU Drn Iso Vlv	SA 282J	Closed	Closed
CV 5065	M-029A	CTMT H_2 Dilution In Iso Vlv	SA 291A	Closed	Closed
DW 6831A	M-010B	RCP STDP Demin Wtr Iso Vlv	SA 291C	Closed	Cpen
CV 5038	M-029A	CTMT H_2 Dilution Out Iso Vlv	SA 291E	Closed	Closed
CV 5090	M-029A	CTMT H_2 Dilution In Iso Vlv	SA 292B	Closed	Closed
DW 6831B	M-010B	RCP STDP Demin Wtr Iso Vlv	SA 292C	Closed	Open
CV 5037	M-029A	CTMT H_2 Dilution Out Iso Vlv	SA 292E	Closed	Closed

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 3

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P 42-1	M-033	DH Pump 1	SA 311A	Start	Various
HV 1467	M-036	CC From DH Clr 1 Out Vlv	SA 311C	Open	Various
HV 2733	M-033	DH Pump 1 Suct Vlv From BWST	SA 311D	Open	Various
HV DH14B	M-033	DH Clr 1 Out Vlv	SA 311E	Open	Various
HV DH13B	M-033	DH Clr 1 Bypass Vlv	SA 311F	Closed	Various
P 42-2	M-033	DH Pump 2	SA 312A	Start	Various
HV 1469	M-036	CC From DH Clr 2 Out Vlv	SA 312C	Open	Various
HV 2734	M-033	DH Pump 2 Suct Vlv from BWST	SA 312D	Open	Various
HV DH14A	M-033	DH Clr 2 Out Vlv	SA 312E	Open	Various
HV DH13A	M-033	DH Clr 2 Bypass Vlv	SA 312F	Closed	Various
HV 1495	M-036	CC Aux Equip In Vlv	SA 321A	Closed	Open
HV 1460	M-036	CC Vlv to Emer Inst Air Cmps	SA 322A	Closed	Open
MU 33	M-031	RC MU Iso Vlv	SA 331I	Closed	Open
MU 38	M-031	RCP Seal Ret Iso Vlv	SA 332F	Closed	Open
MU 66A	M-031	RCP 2-1 Seal In Iso Vlv	SA 332E	Closed	Open
MU 66B	M-031	RCP 2-2 Seal In Iso Vlv	SA 331J	Closed	Open
MU 66C	M-031	RCP 1-1 Seal In Iso Vlv	SA 331K	Closed	Open
MU 66D	M-031	RCP 1-2 Seal In Iso Vlv	SA 332G	Closed	Open
MU 59A	M-031	RCP 2-1 Seal Ret Vlv	SA 331E	Closed	Open
MU 59B	M-031	RCP 2-2 Seal Ret Vlv	SA 331F	Closed	Open
MU 59C	M-031	RCP 1-1 Seal Ret Vlv	SA 331G	Closed	Open
MU 59D	M-031	RCP 1-2 Seal Ret Vlv	SA 331H	Closed	Open

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 4

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
		SFAS Incident Level 4			
P 56-1	M-034	CS Pump 1	SA 411A	Start	Off
P 56-2	M-034	CS Pump 2	SA 412A	Start	Off
CC 1411A	M-036	CC In Iso Vlv to CTMT	SA 421A	Closed	Open
CC 1407A	M-036	CC Out Iso Vlv from CTMT	SA 421B	Closed	Open
CC 1567A	M-036	CC In Iso Vlv to CRD	SA 421C	Closed	Open
CC 1328	M-036	CC CRD Booster Pump 1 Suct Vlv	SA 421D	Closed	Open
CC 1411B	M-036	CC In Iso Vlv to CTMT	SA 422A	Closed	Open
CC 1407B	M-036	CC Out Iso Vlv from CTMT	SA 422B	Closed	Open
CC 1567B	M-036	CC In Iso Vlv to CRD	SA 422C	Closed	Open
CC 1338	M-036	CC CRD Booster Pump 2 Suct Vlv	SA 422D	Closed	Open
MS 101	M-003	Mn Stm Line 1 Iso Vlv	SA 431A	Closed	Open
FW 612	M-007	Mn FW 1 Stop Vlv	SA 431C	Closed	Open
MS 100-1	M-003	Mn Stm Line 1 WU Iso Vlv	SA 431E	Closed	Closed
MS 100	M-003	Mn Stm Line 2 Iso Vlv	SA 432A	Closed	Open
FW 601	M-007	Mn FW 2 Stop Vlv	SA 432C	Closed	Open
MS 100-1	M-003	Mn Stm Line 2 WU Iso Vlv	SA 432E	Closed	Closed

SFRCS INITIATION RECOVERY GUIDELINE

The purpose of this section is to act as a guide to restore plant operation to the normal mode of MFW feeding the SGs and the TBVs dumping steam to the condenser. This will allow the AFW System to be returned to standby and termination of steam dumping to the atmosphere via the atmospheric vents. The assumptions used in writing this section were that the SFRCS actuated on a signal other than a MFW or MS rupture. If a rupture is suspected, it should be determined if it can be isolated and a normal cooldown conducted (possibly on one SG) or consideration should be given to conducting a cooldown on AFW and the AVVs. A rupture, or condition such as a stuck open MSSV which prevents restoring normal feed and steaming on one SG, will make the below steps on that SG non-applicable.

1. Take control of OTSG pressure using the atmospheric vents to stop secondary side safety valve lifting.

_____1.1 Place both atmospheric vent valves hand/auto stations in "hand" at zero demand.

_____1.2 Press both atmospheric vent valves block buttons (HIS-ICS-11D and HIS-ICS-11C).

_____1.3 Press "auto" on HIS-ICS-11B and HIS-ICS-11C.

_____1.4 Control OTSG pressure as desired to prevent lifting secondary side safety valves. The valves may be placed in "auto" if desired.

_____2. Trip both Main Feed Pump Turbines.

3. If condenser vacuum has been lost, open the condenser vacuum breakers and lockout the Mechanical Hogger.

_____3.1 Open the condenser vacuum breakers using HIS-634 on Panel C-5721.

_____3.2 Lockout the Mechanical Hogger using HIS-1005 on Control Room Panel C-5721.

4. Have an operator start up the Auxiliary Boiler and charge the Auxiliary Steam Header.

_____4.1 Start up the Auxiliary Boiler per SP 1106.04.

5. Locate and correct the cause of the loss of normal feedwater if possible. If loss of normal feed was due to a pipe rupture, ensure isolation of the rupture. The cause of loss of normal feed could be one of the following:

_____5.1 A feed line rupture.

_____5.2 Loss of both main feed pumps.

_____5.3 Inadvertent closure of Main Feedwater Control Valves, Startup Control Valves, or Main Feedwater Block Valves.

_____5.4 Inadvertent SFRCS actuation.

_____5.5 Loss of steam pressure control causing SFRCS actuation, i.e., a stuck open MSIV.

6. When the 235 psig steam header is on the Auxiliary Boiler, re-establish seal steam and condenser vacuum.

_____6.1 Establish gland steam per SP 1106.03.

_____6.2 Establish condenser vacuum per SP 1104.35.

7. Before normal feedwater control can be accomplished, the SFRCS low level manual trips must be reset. The SUFP must be started to clear the SFRCS steam to feed ΔP trips.

_____7.1 To reset the manual low SG SFRCS trip, push off buttons on SG LVL LOW TRIP BUTTONS (4869 and 4970) on SFRCS manual initiation selection of Control Room Panel C-5721.

_____7.2 Start the SUFP per SP 1106.27.

_____8. If normal feedwater cannot be established, a cooldown will have to be conducted using the Auxiliary Feedwater System and the atmospheric vents.

_____9. If cooldown using the AFPs is required for an extensive period such that the CST water is exhausted, the automatic shift to service water should be verified or manually initiated if CST level falls below three feet.

9.1 Four pressure switches (two for each AFP) automatically shift AFP suction to service water on low AFP suction of 2 psig. If manual initiation is necessary, open SW 1382 (SW to AFP 1-1 suction and SW 1383 (SW to AFP 1-2 suction) and close FW 786 (AFP 1-1 suction valve) and FW 790 (AFP 1-2 suction valve).

_____10. If the SFRCS trips could be reset, restore normal OTSG heat removal by continuing with the following steps

_____11. Place the turbine bypass valves in hand and close the turbine bypass valves.

12. Open the Main Steam Non-return Valves MS 209 and MS 210.

_____12.1 Press open on HIS 209 and HIS 210 on Control Room Panel C-5722.

13. Press the closed buttons for MSIV 100 and MSIV 101. Then reset the SFRCS solenoids for MSIV 100 and MSIV 101.

_____13.1 HIS 100 and HIS 101 are located on Control Room Panel C-5717.

_____13.2 The SFRCS resets for MSIV 100 and MSIV 101 are located on the north wall of the Control Room Cabinet Room. Both resets must be pushed for each MSIV.

_____14. Equalize pressure across the MSIVs by opening the MSIV Bypass Valves MS 100-1 and MS 101-1.

15. If the dP across the MSIVs is greater than 250 psig and stable, isolate the main steam line traps and drains per Attachment 2 of this procedure. Restore the lineup after MSIVs are open.

_____15.1 Main Steam Isolation Valve dP for Line 1 is determined by comparing OTSG 1 pressure SP12B to turbine header pressure SP16B on the front consoles.

_____15.2 Main Steam Isolation Valve dP for Line 2 is determined by comparing OTSG 2 pressure SP12A to turbine header pressure SP16A on the front console.

_____16. When the dP across the MSIVs is less than 250 psid, place the atmospheric vent valves in hand and then open MS 100 and MS 101.

_____17. Using the hand/auto stations, take control of steam generator pressure with the turbine bypass valves and close the atmospheric vent valves.

_____18. Place the main feedwater valves and startup feedwater valves ICS stations in hand and close them. Reset the main feedwater valves and startup feedwater valves SFRCS trips.

_____18.1 Reset the Startup Feedwater Valves SP7A and SP7B SFRCS trips by pushing the reset pushbuttons on the west wall of the Control Room Cabinet Room.

_____18.2 The Main Feedwater Valves SP6A and SP6B SFRCS trips are reset by pushing reset pushbuttons located 603' elevation, east wall of the Turbine Building at SP6A and SP6B.

_____18.3 Reset the MFW Block Valves FW 779 and FW 780 by placing their control switches to OFF then back to AUTO.

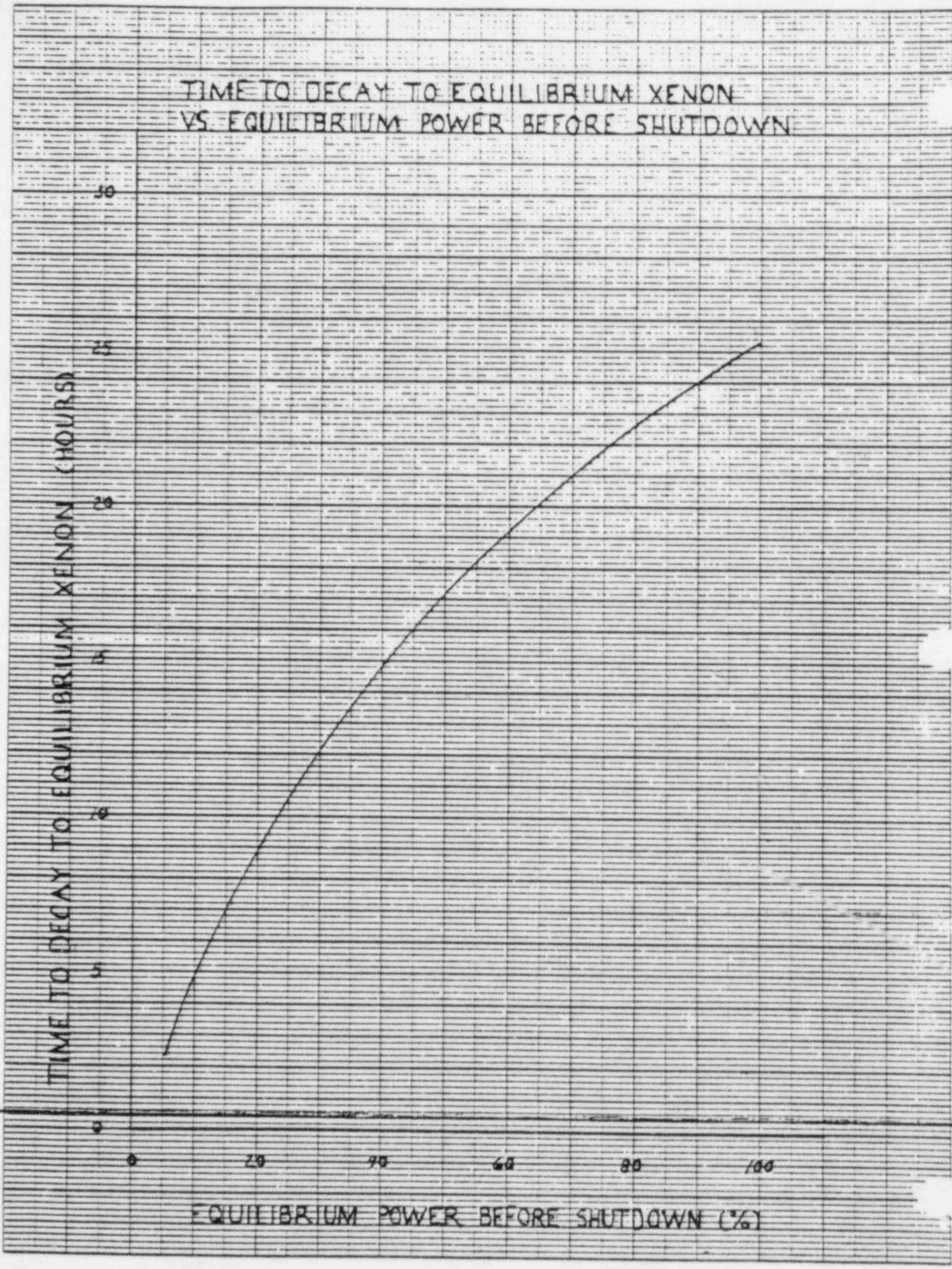
19. When the decay heat load is low enough to prevent running out to SUFP, establish main feedwater flow to the OTSGs. This may

require from one to two hours after reactor shutdown depending on the power history.

_____19.1 SUFP is rated for 300 gpm at 900 psig. Ensure AFW flow to both OTSGs is less than 300 gpm prior to shutting down AFPs.

_____19.2 Establish MFW flow to OTSGs by opening FW 601 and FW 612, Main Feedwater Stop Valves, and then throttling open SP7A and SP7B, Startup Feedwater Valves, from their ICS stations. Run the AFW governors to the low speed stops in manual.

_____20. When OTSG levels are being maintained by the SUFP alone, shutdown the AFPs per SP 1106.06, Section 7.



END

FIGURE 1
Sheet 1 of 1

POST TRIP REVIEW GUIDELINES

July 3, 1984

Purpose

The purpose of this booklet is to provide guidance on the performance of a review of a plant transient or trip. This is intended as generic guidance only and is not intended to cover every possible event. Each event should be reviewed on an individual basis with the scope of review determined by the type of event.

Transient analysis is basically divided into four phases:

1. Data Collection
2. Data Analysis
3. Support of Outside Organizations
4. Report Preparations and Review

These guidelines will discuss each of the four phases.

1. DATA COLLECTION

1.1 Information Available

The capability to record and recall the plant information necessary to assist in the determination of the cause or causes of unscheduled reactor trips currently exists at Davis-Besse Unit 1. Digital indications (e.g., on/off, open/close, etc.) and key analog information are recorded by various transient monitoring systems during a reactor trip for subsequent analysis. The Plant Process Computer records and displays both digital and analog information. The Data Acquisition and Display System (DADS) located in the Technical Support Center also provides a means for recording and displaying analog information. An additional source of analog information used to support post trip efforts comes from the Control Room strip chart recorders. These systems provide the primary sources of information used for trip analysis at Davis-Besse Unit 1.

Plant Process Computer

The Plant Process Computer monitors digital and analog information from all major plant systems. Approximately 2,500 digital points and 2,000 analog points are fed into the computer. Some of this information is manipulated and stored for plant performance monitoring purposes, and all of the information is available to the Control Room operator in various display formats. Three functions of the Plant Process Computer provide information useful for transient analysis efforts. These functions include the Sequence of Events Monitor, the Post Trip Review, and the Alarm Printout.

The Sequence of Events (SOE) Monitor is designed to provide a sequential list of important plant events. All inputs to this function are digital. The list of monitored points is provided as Enclosure 1. A change of state of any of these digital points is recorded in the SOE file along with the time of occurrence. The time of occurrence listed with the event is based on computer clock time and recorded to the nearest five milliseconds. The SOE file can hold up to 256 records. Once the SOE file is filled, subsequent events replace the oldest recorded event in the file. The first event to be recorded in the file triggers an indicator to the operator that an SOE monitored event has occurred. This indication is cleared, and the SOE file is emptied when the operator requests a printout of

the SOE file. Enclosure 2 illustrates the format of information presented in the SOE printout.

The Post Trip Review function is designed to record selected analog information for a period of time before and after a reactor trip. The list of parameters monitored by this function is provided in Enclosure 3. The most recent 15 minutes of historical values for these parameters is maintained in a rolling file. In the event of a reactor trip, this rolling file is frozen and data for the next 15 minutes is recorded. An indication that the Post Trip Review function has been initiated is provided to the operator. The operator may then request the Post Trip Review printout which clears the file. The Post Trip Review printout provides parametric data in engineering units given at 15 second intervals from 15 minutes prior to the trip until 15 minutes after the trip. Enclosure 4 provides a sample of one segment of a Post Trip Review printout. Note that some of the parameters monitored have scan intervals of more than 15 seconds. Consequently, some data may be repeated in successive 15 second records. The parameters monitored for the Post Trip Review function were chosen as a part of the original plant process computer design. The variables monitored are key parameters of the major primary and secondary systems which could indicate abnormal trends that may lead to, or result from, a reactor trip. Normally inoperative safety systems are not monitored by this function. The scan intervals selected for the parameters were based on the anticipated rates of change of the individual parameters, and multiplexing hardware and memory capacity limitations that existed at the time of the initial design.

The Alarm Printout function provides an historical listing of both digital and analog information recorded when the monitored parameters enter a predetermined alarm state. Essentially, all digital and analog input points are monitored for alarm status. Alarm messages are recorded as they occur on the alarm printer along with the time of occurrence. No operator action is required to initiate the Alarm Printout. All digital points are scanned once per second, and a change of point status is identified on the alarm printer. Analog points are scanned at varying intervals (either 1, 5, 15, 30, or 60 second intervals) and are compared at each scan to a predetermined alarm value. Each time the parameter exceeds the alarm limit or returns to within limits, the event is recorded on the Alarm Printout. An example of a section of the Alarm Printout is provided in Enclosure 5.

The Plant Process Computer consists of redundant MODCOMP Classic 7870 CPUs. The CPUs are powered from separate uninterruptable instrumentation buses YAU and YBU. The uninterruptable buses are supplied from the station battery backed 250 volt DC power supply system through an inverter. Power can also be supplied to the bus from a nonessential regulated instrumentation bus through a static transfer switch within the inverter. The redundant CPUs were installed during the 1982 Refueling Outage

as a part of the overall project to upgrade the Plant Process Computer system. The multiplexers providing inputs to the processors will be replaced in future outages. The multiplexers are currently supplied from YBU, consequently, a loss of YBU will interrupt all three transient monitor functions of the Plant Process Computer. The DADS will still be functional. As the multiplexers are replaced, they will be equipped with redundant power supplies.

Data Acquisition and Display System (DADS)

The DADS, located in the Technical Support Center, was designed as a part of the emergency response facilities at Davis-Besse Unit 1. The primary function of the system is to provide information to emergency response personnel in the Technical Support Center to assist in evaluating plant status in an accident situation. Consequently, those variables important to determining the safety status of plant systems and the proper functioning of safety systems are inputs to the DADS.

While the DADS receives inputs from numerous sources, such as the Meteorological Tower and the Plant Process Computer, the inputs of importance to the transient monitoring function are supplied through a separate multiplexer (the Validyne). The list of parameters supplied by this multiplexer is provided in Enclosure 6. The scan rate for these variables is approximately once per second. Data is recorded at that rate for a period of 24 hours in a rolling file. Access to information in this data file is possible in several formats. Individual points or groups of points can be examined by a CRT or a line printer output. Additional output formats are being developed and will include the use of a printer/plotter to provide graphical trends.

The Prime Comupter stores information from both the MODCOMP and Validyne inputs. These values can be called up and printed out per Section 1.2. The power supply for the multiplexer located in the station is YAU. The power supply for the DADS computer system is independent of the station electrical system. The Davis-Besse Administration Building (DBAB) which houses the Technical Support Center and the DADS, is supplied from a construction feeder independent of the three 345 KV lines connected to the station grid. The DBAB electrical system supplies an emergency response facilities bus which can also be fed by an emergency diesel generator through an automatic transfer switch. The emergency response facilities bus in turn feeds an uninterruptable distribution network. Power to the uninterruptable distribution network is backed up by a battery driven system through a static transfer switch which assures continuous operation of the DADS computer system. The emergency battery system is charged from the emergency response facilities bus.

Strip Chart Recorders

In the event that the Plant Process Computer and the DADS are unable to perform their transient monitor functions, the Control Room strip chart recorders act as a backup source of information for transient analysis. Due to the compressed time scales of the strip chart recorders, the information cannot be used for sequence of events determination and the limited number of parameters recorded make determination of the cause of a transient very difficult. However, the parameters that are recorded are important major system parameters such as pressurizer level, Reactor Coolant System (RCS) pressure, steam generator levels, feedwater flows, etc. The information available on the strip chart can be very useful in assuring that major system upsets did not occur as a result of the transient. Strip chart recorders are also useful in recognizing long term trends that may be indicative of problems leading to, or resulting from, a transient.

1.2 Technical Section Function

It has become a Technical Section function to collect all the available plant data and have copies given as soon as possible to the Assistant Station Superintendent (Steve Quennoz), Operations (Dale Miller), NRC Resident Inspector (Walt Rogers), and I&C (acting I&C Engineer). This job normally requires a trip to the Control Room to retrieve the alarms (at least 20 minutes prior to trip and for an hour after), the SOE printout and the Post Trip Review (may have to ask the operators to print out).

If possible, attempt to set up a post trip meeting which includes operators from the shift that was on. Copies of the Reactor Operator Log and Unit Log should also be obtained when completed (usually not until the day after the trip).

If possible, talk with the operators which are on shift. The purpose of this interview is to record pertinent information as seen by the operator during a transient condition. The interview should be conducted as soon as possible after the event. Typical questions are:

1. Briefly describe plant conditions prior to the trip. (Include Integrated Control System (ICS) mode and pertinent testing, operations, or maintenance in progress or recently completed.)

2. What was the first indication or alarm which keyed you to a problem? What actions did you take as a result of these indications?

3. Were any alarms or indications out of service or did any fail during the course of the transient? Did any indications or alarms mislead you? Could the Control Room alarms or controls have been relocated in such a manner to have aided your actions on this transient?

4. Did existing plant procedures provide adequate action for this transient? Was it necessary to take action beyond their scope.

5. What additional information or guidance do you feel would have assisted you during the transient?

6. Summarize the transient including both indications and actions. Discuss any equipment problems observed.

The data from the Prime Computer must be manually hard copied within 24 hours of the trip as follows:

1) Go to the Technical Support Center Computer Room and turn on the orange line printer (the "run" light should be "on", the "off" light should be lit unless the printer is in the act of printing).

2) Turn on a Technical Support Center Ramtek terminal and push reset button located at the rear of the keyboard.

3) At the Ramtek terminal: (NOTE: two runs, one of 35 minutes length and 30 seconds interval, and a second of 5 minutes at 1 second interval provide the best data)

ENTER: LOGIN_TSC

HIT: f_3 function key (hard copy)

HIT: f_1 function key (to obtain Validyne data)	OR	f_2 function key (for selected MODCOMP points)
		ENTER: point number
ENTER: P (to output to line printer)		
ENTER: beginning hours and minutes HHMM Run 1: use 5 minutes before trip Run 2: use 1 minute before trip		ENTER: starting time using HHMM format (normally use 5 minutes before trip)
ENTER: number of minutes wanted to display Run 1: use 30 minutes Run 2: use 5 minutes		ENTER: how long in HHMM (normally 30 minutes)
ENTER: interval desired in seconds Run 1: use 30 seconds Run 2: use 1 second		ENTER: interval in minutes or <CR> for 30 seconds
ENTER: point number or "ALL" for all Validyne points		
Data will now be printed*		Data will now be printed*

4) To exit, enter LO

*If data does not print, do not repeatedly attempt to request printouts since all requests will be remembered and printed when the system returns to working order. Call for assistance from Computer personnel.

The Prime data can be displayed on the Ramtek terminal and a video copy of the display obtained on the Tektronix hard copy printer.

1) Go to the TSC, turn on Tektronix Video copy printer and let warm up.

2) Turn on a Ramtek terminal and press reset button located at the rear edge of the keyboard.

3) At the Ramtek:

   ENTER: LOGIN_LARRY_SMART1
   ENTER: DIS
   ENTER: OB
   ENTER: SEG_#DISPLAYS

   ENTER: 4 (to plot data vs. time)
   ENTER: 1 (for CRT display)
   ENTER: 2 (to access 24 hour circular file data)
   ENTER: 1 (always)

   HIT: Return if data displayed looks OK when presented for review

   ENTER: Point number (NOTE: If a Validyne point is requested, V must prefix the point number, i.e., VT801 RCP 2-1 Tc
   VZ675 MN FW S/O CTRL VLV 1)

   Data will now be displayed and updated on the terminal.

4) To obtain a video copy of the Ramtek display:

   With the display finished updating, press the black button beside the terminal and the video copy will be automatically taken.

   If it is desired to freeze the display during updating, the terminal can be frozen by hitting "control" "S" (simultaneously).

   To resume updating:

   HIT: "control" "Q" (simultaneously)

5) To exit program:

   HIT: "Break" key

   ENTER: "Q"

   ENTER: LO

The printer/plotter is being programmed to have a fixed set of plots (see Enclosure 10 for list) be printed by manual command. Presently, only Larry Konopka can use this feature. This will, in the future, be the primary method of data retrieval. Details of use will be added later.

2. DATA ANALYSIS

Data analysis is the most difficult part of the post trip review process. Every analysis is different since every event is different. Some points need to be checked for almost every event, and the following provides an indication of the extent of the review required.

The SOE and Alarm Printout must be reviewed to verify the safety systems operated as required. This means verifying not only why some channels tripped, but also verifying that all channels that should have tripped did trip. Enclosure 7 provides a list of all SOE points and what causes the SOE to initiate. Enclosure 8 has a list of specific points to be checked.

The plots must be reviewed to determine if the overall plant response was acceptable. After a trip, the main feedwater control valves are closed, the startup feedwater valves are targeted to approximately 20% open, and the main feed pump speed is increased to target (approximately 4600 RPM) by the rapid feedwater reduction system. Steam generator levels should be maintained at 35 inches (and rapid feedwater reduction startup feedwater valve target released). The main steam safety valves should reseat at approximately 960 PSIG and Tave should tend towards 551°F. Pressurizer level should reach a minimum of 10-20 inches if originally at full power (higher if originally at lower power).

RCS pressure should not fall below 1800 PSIG unless problems occur with main steam safety valves (MSSV)s resetting or makeup flow is inadequate. Cold leg temperature will most likely rise for the first 10-20 seconds from the drastically increasing steam generator pressure, but will then tend toward 550°F. Since 100% FP is 48°F ΔT (Th - Tc), the post trip ΔT is approximately 2-3°F for the first 20 minutes (dependent on decay heat load).

The drastic changes in steam generator pressure will cause momentary glitches in the steam generator level transmitters. These are to be expected since the level transmitters are just ΔP indicators.

High deaerator levels have been a problem post trip. It appears the Deaerator Level Control Valve #2 fails to close and the equalizing valve caused both deaerator levels to increase. Monitor both deaerator levels and the time the condensate pumps are reduced to one operating.

All turbine bypass valves should normally open initially after the trip and then close during the MSSV blowdown. The atmospheric vents should open when steam generator pressure rises above 1025 PSIG (providing no Steam and Feedwater Rupture Control System (SFRCS) actuation).

RCS pressure, pressurizer level, and RCS Tave should have nearly identical curve shapes until the makeup pumps have added significant volume (1-2 minutes). RCS pressure is the most sensitive indicator of RCS temperature; the RTDs and thermowells response time, as well as the loop transport time, adds a significant time delay (5-15 seconds) in the sensing of actual Tave during a rapid coolant temperature change.

One additional caution is necessary on using the out-of-core power range NIs. These detectors are monitoring core neutron leakage, which is affected drastically by changes in cold leg temperature (approximately .5% FP per °F). If Tc increases 6°F, indicated core power will increase 3% without any actual change in core power.

The analysis performed depends largely on the transient. A closure of one main steam isolation valve (MSIV) requires a much more detailed review than a "screwdriver" trip. An imbalance trip requires a detailed core physics review, while an electro-hydraulic control (EHC) induced transient may require a significant review of the secondary plant. Common sense and an inquisitive attitude must be maintained throughout the review. Murphy's Law definitely applies to nuclear power; Don't assume anything worked like it should.

3. SUPPORT OF OUTSIDE ORGANIZATIONS

The Technical Section provides support to the TAP Team and places information on NETWORK to provide information to outside organizations. The B&W Resident Engineer (Jim Albert) has his own method of communication with other B&W plants (ELEX) which can also be used as the method of communication between B&W units.

Within 48 hours of the event, the Technical Section should make an entry on NETWORK to the other B&W units describing the event. If the event has significance beyond the B&W design (such as failure mechanism of MSSVs), an entry should also be made on NETWORK to all operating units.

The Technical Section is responsible for telling the B&W Resident Engineer if a TAP Team site visit is desired. A TAP Team should be called in for most involved transients, but no site visit is necessary for a well understood transient. When requesting a site team, ask for personnel qualified in the area of the equipment involved in the transient; i.e., if ICS operation is in question, ask for an ICS "expert".

The Technical Section representative acts as a liaison for the B&W TAP Team. The entrance interview should be well prepared with all information necessary to analyze the event provided to the team. They should be provided with:

1) An oral review of the transient details known

2) All plots, alarms, SOE, post trip review, and operator logs

3) Names, work extension, and schedule of personnel who were on shift during transient

4) A work area - typically a conference area in the DBAB

5) Escorts as required into the protected area

After the draft report is prepared, we have Duplicating make 10-12 copies. An exit interview is then set up with Steve Quennoz, Bernie Beyer, I&C Engineer, Dale Miller, Louis Simon, other available operators, Shift Technical Advisors, Jim Albert, and the Technical Section representative. The draft report is then reviewed and several days given to receive comments.

If the TAP Team was not called in, only the NETWORK entry need be completed. Section 4 describes the details of report preparation to be followed.

4. REPORT PREPARATION AND REVIEW

A TAP report will be prepared for all unscheduled reactor trips at Davis-Besse. Reports may also be prepared for other significant events. The purpose of the report is to provide transient event information for all members of the 177 FA Owners Group. The operational experience shared in this program will lead to improved plant reliability and a better understanding of the plant's performance by all participants.

The format of the report should be as follows:

I. Executive Summary
   A. Plant Name, Data, Time of Trip
   B. Brief Description
   C. Root Cause
   D. Performance Anomalies
   E. Lessons Learned

II. Transient Assessment
   A. Sequence of Events
   B. Plant Performance
      1. Pre-trip Review
      2. Initiating Event
      3. Plant Post-trip Response
      4. Operator Actions/Procedural Adequacy
   C. Safety Considerations
   D. Assessment Conclusions
   E. Annotated Plots

The "Executive Summary" section should be a single page containing the following information: plant name, date and time of trip, brief description of the event, including initial power level, root cause of the transient, any performance anomalies, and lessons learned.

The "Sequence of Events" section should contain those major events or conditions which delineate the progressive course of the transient. It normally contains a combination of the SOE, alarms, and Reactor Operator Log.

The "Pre-trip Review" section should contain a statement of the plant conditions prior to the transient. Examples to be included would be power level, ICS status, maintenance or testing in progress, and equipment deficiencies.

The "Initiating Event" section should describe the sequence of events and plant conditions leading up to transient initiation. Try not to be repetitive with other sections.

The "Plant Post-trip Response" section should include a discussion of the response of the NSS and BOP from a process point of view; i.e., Tave, reactor coolant pressure, pressurizer level, feedwater flow, OTSG level, and main steam pressure. These parameters should be plotted versus time and annotated to indicate major events, departures, etc., to support the text of this section. Also, this section should include a discussion of performance of components and their departures from the expected. Proposed corrective actions and corrective actions previously completed should be included in the text of this section.

The "Operator Action/Procedural Adequacy" section should include information concerning specific operator actions taken during the transient which have not been included in any previous sections. Additionally, procedures followed during the transient, and any information which would be beneficial to other operators should be included. This section is of major interest to other operators regarding the TAP report and should be as detailed as possible. Operator interviews, operator logs, computer printout and plant procedures provide good source material. This section should provide an evaluation of the shift operator's ability to use the procedures to mitigate a plant transient. Avoid repetition of earlier sections when possible.

The "Safety Considerations" section should include the basis for which safety, as it relates to the transient, has been considered. Those bases may include plant design requirements, Final Safety Analysis Report (FSAR) accident analysis, or other information.

The "Assessment Conclusions/Corrective Actions" section should be a summary of the significant aspects of the transient, including departures from expected component and plant performance, suggested/actual corrective actions, and any preventative measures if not already discussed in the Plant Post-trip Response section. For component failures, list name, model and serial number, manufacturer name, date of installation, etc. Try to give this section a positive, "we're fixing it" tone instead of a "dink sheet".

The "Annotated Plots" section should consist of a number of parameter versus time plots annotated with trip times and other important occurrences (pump starts/stops, emergency Safety Features Actuation System (SFAS) initiation, power operated relief valve (PORV) lifts, main steam relief valve (MSRV) / MSSV lifts, etc.) The Abnormal Transient Operator Guidelines (ATOG) P-T plot should be included in this section.

After the report has been reviewed in the exit meeting and modified by the Technical Section, it is sent out for review (see Laura for distribution). After the date that the comments were due (usually two weeks), the report comments are incorporated, and it is then sent to the Station Review Board (SRB). After SRB review and comment incorporation, the report will be sent to B&W with the cover letter signed by the Technical Section TAP representative. B&W will place the report in the booklets and distribute to all participating utilities.

The data is then stored in the trip files (along with the Attachment 3 to PP 1102.03 from Operations). Revisions are not normally made to TAP reports, but can be completed if serious errors exist.

This completes the post trip review guidelines - these are only guidelines and are not cast in concrete. Enclosure 9 includes a checklist for post trip review which may be used to ensure no items are missed.

SEQUENCE OF EVENTS POINTS LIST

Auxiliary Transformer 11 Trouble

Bus A Electrical Fault

Bus B Electrical Fault

Bus A to Transformer AC Breaker

Bus C2 Trouble

Bus D2 Trouble

Control Rod Drive (CRD) Trip Confirm

CRD Channel AC Any Trip Device

CRD Channel BD Any Trip Device

Electro Hydraulic Control Emergency Trip System Low Pressure

Emergency Diesel Generator 1 Trouble

Emergency Diesel Generator 2 Trouble

Essential Bus C1 Trouble

Essential Bus D1 Trouble

Essential Transformer CE 1-1 Trouble (typical CE 1-1, DF 1-1, CE 1-2), DF 1-2)

Generator and Main Transformer Overall Differential Trip

Generator Overcurrent Trip

Generator Reverse Current Power Trip

Generator Field Failure

Generator Out of Step

Generator Underfrequency

Generator Differential

Generator Ground Current

Enclosure 1
Page 1 of 3

Main Feed Pump Turbine (MFPT) 1 Trip (typical MFPTs 1 and 2)

Main Transformer Sudden Pressure Change

Moisture Separator Reheater 1 High Level Turbine Trip

Moisture Separator Reheater 2 High Level Turbine Trip

Reactor Protection System (RPS) Channel 1 Flux/Delta Flux/Flow Trip (typical Channels 1 through 4)

RPS Channel 1 High Flux/Number of Reactor Coolant Pumps (RCPs) Running Trip (typical Channels 1 through 4)

RPS Channel 1 Reactor Coolant (RC) Pressure/Temperature (typical Channels 1 through 4)

RPS Shutdown Bypass High Pressure Trip (typical Channels 1 through 4)

RPS Channel 1 Containment High Pressure Trip (typical Channels 1 through 4)

RPS Channel 1 RC High Pressure Trip (typical Channels 1 through 4)

RPS Channel 1 RC Low Pressure Trip (typical Channels 1 through 4)

RPS Channel 1 Channel Trip (typical Channels 1 through 4)

RPS Channel 1 High Flux Trip (typical Channels 1 through 4)

RPS Channel 1 RC High Temperature Trip (typical Channels 1 through 4)

RPS Startup Rate Rod Withdrawal Inhibit

RC Pressurizer Low Level Heater Interlock

RCP 1-1 Motor Trouble (typical RCPs 1-1, 1-2, 2-1, and 2-2)

Safety Features Actuation System (SFAS) Channel 1 Borated Water Storage Tank (BWST) Level Low (typical Channels 1 through 4)

SFAS Channel 1 Containment Pressure > 38.4 psia (typical Channels 1 through 4)

SFAS Channel 1 Containment Pressure > 18.4 psia (typical Channels 1 through 4)

SFAS Channel 1 RC Pressure < 1650 psig (typical Channels 1 through 4)

SFAS Channel 1 RC Pressure < 450 psig (typical Channels 1 through 4)

SFAS Channel 1 Containment Radiation High (typical Channels 1 through 4)

Steam and Feedwater Rupture Control System (SFRCS) Full Trip

SFRCS Differential Pressure Half/Full Trip Steam Generator (SG) 1 (typical SGs 1 and 2)

Startup Transformer 01 Trouble

Startup Transformer 02 Trouble

Switchyard Oscillograph Started

Switchyard Bus J Differential

Switchyard Breaker 34563 Open/Closed (typical five breakers)

Turbine Generator Mechanical Trip Solenoid Turbine Trip

Turbine Generator Master Turbine Trip

Turbine Generator Mechanical Trip Valve Trip

Turbine Generator Master Trip Solenoid Trip

Turbine Bypass Valve 1-1 Open/Closed (typical six valves)

Unit Seismic Instrumentation Started

:D DAVIS-BESSE UNIT 1

ROUP 10 SEQUENCE OF EVENTS REVIEW
1:30:27 10/15/83

1:26:13:170	X027	SWYD ACB 34562	OPEN
1:26:31:495	P702	SFRCS OP HALF/FULL TRIP ,SG 2	TRIP
1:26:31:565	P702	SFRCS OP HALF/FULL TRIP ,SG 2	NORM
1:26:41:895	Q963	SFRCS FULL TRIP	TRIP
1:26:41:905	X038	T-G MASTER TURB TRIP	TRIP
1:26:41:940	X030	T-G MASTER TRIP SOLENOIDS	TRIP
1:26:41:945	Q181	CRD CB B/D ANY TRIP DEVICE	TRIP
1:26:41:950	Q180	CRD CB A/C ANY TRIP DEVICE	TRIP
1:26:42: 45	Q266	CRD TRIP CONFIRM	TRIP
1:26:42:165	X033	T-G MECH TRIP SOLENOID TURB TRIP	TRIP
1:26:42:185	X032	T-G MECH TRIP VLV	TRIP
1:26:44:420	P382	EHC EMER TRIP SYS LOW PRESS	TRIP
1:27:11:540	J428	GEN REVERSE PWR	TRIP
1:27:11:565	X026	SWYD ACB 34561	OPEN
1:27:11:565	X025	SWYD ACB 34560	OPEN
1:27:13:630	J428	GEN-REVERSE PWR	NORM
1:27:32: 95	Y060	TURB BYPASS VLV 1-1	NC
1:27:32:445	Y060	TURB BYPASS VLV 1-1	CLOS
1:27:50:630	Y063	TURB BYPASS VLV 2-1	NC
1:27:52: 5	Y063	TURB BYPASS VLV 2-1	CLOS
1:33: 1:815	Q963	SFRCS FULL TRIP	NORM
1:33:18:730	Q841	RPS SU RATE ROD WTHDRWL INHIBIT	INHB
1:34: 3:165	Q841	RPS SU RATE ROD WTHDRWL INHIBIT	NORM
1:13:27:755	X026	SWYD ACB 34561	CLOS
1:13:32:820	X025	SWYD ACB 34560	CLOS

Enclosure 2
Page 1 of 1

POST TRIP REVIEW POINT LIST

Auxiliary Feed Pump Turbine 1 Speed (typical Pumps 1 and 2)

Channel 1 Power Range Flux (typical Channels 1 through 4)

Channel 1 Power Range Delta Flux (typical Channels 1 through 4)

Condensate Pump Flow

Control Rod Drive Group 5 Position (typical Groups 5 through 8)

Deaerator 1 Storage Tank Level (typical Deaerators 1 and 2)

Generator Gross Megawatts

High Pressure Condenser Pressure

High Pressure Condenser Hotwell Level

High Pressure Turbine First Stage Turbine End Pressure

High Pressure Turbine First Stage Generator End Pressure

High Pressure Turbine Side 1 Inlet Temperature

High Pressure Turbine Side 2 Inlet Temperature

Low Pressure Condenser Pressure

Main Feedwater Average Flow Loop 1 (typical Loops 1 and 2)

Main Feedwater Temperature (typical Loops 1 and 2)

Main Feedwater Compensated Flow (typical Loops 1 and 2)

Main Feedwater Pump Turbine 1 Speed (typical Pumps 1 and 2)

Pressurizer Average Level

Pressurizer Pressure

Reactor Coolant Makeup Tank Level

Reactor Coolant Makeup Flow

Reactor Coolant Pump (RCP) Seal Injection Flow

RCP 1-1 Discharge Cold Leg Narrow Range Temperature (typical RCPs 1-1 and 2-1)

Reactor Coolant System (RCS) Loop 1 Hot Leg Narrow Range Temperature (typical Loops 1 and 2)

RCS Average Temperature

RCS Loop 1 Hot Leg Narrow Range Pressure (typical Loops 1 and 2)

RCS Average Hot Leg Total Flow

RCS Letdown Boron Concentration

Safety Features Actuation System (SFAS) Channel 1 Containment Pressure

SFAS Channel 1 Containment Radiation Core Power

SFAS Channel 3 Borated Water Storage Tank Level

Steam Generator (SG) 1 Full Range Level (typical SGs 1 and 2)

SG 1 Startup Level (typical SGs 1 and 2)

SG 1 Operate Level (typical SGs 1 and 2)

SG 1 Outlet Temperature (typical SGs 1 and 2)

SG 1 Outlet Pressure (typical SGs 1 and 2)

SG 1 Feedwater Pressure (typical SGs 1 and 2)

TED DAVIS-BESSE UNIT NO. 1

GROUP 3 POSTTRIP REVIEW
19:52:23 1/15/1983

1/15/1983

REACTOR PROTECTION SYSTEM (RPS)

TIME	CH1 PR NI6 FLUX% R795	CH2 PR NI5 FLUX% R804	CH3 PR NI8 FLUX% R814	CH4 PR NI7 FLUX% R820	CH1 PR NI6 DFLUX% R794	CH2 PR NI5 DFLUX% R803	CH3 PR NI8 DFLUX% R813	CH4 PR NI7 DFLUX% R819
16:44: 9	101,0	100,6	100,8	100,3	-12,888	-12,415	-12,796	-13,040
16:44:24	100,8	100,6	100,9	100,6	-12,964	-12,521	-12,857	-12,979
16:44:39	100,8	100,6	101,0	100,6	-12,964	-12,521	-12,918	-13,086
16:44:54	101,0	100,6	101,0	100,6	-12,964	-12,521	-12,918	-13,086
16:45: 9	100,9	100,4	100,7	100,5	-13,086	-12,521	-12,918	-13,086
16:45:24	101,0	100,7	101,0	100,3	-13,086	-12,521	-12,918	-13,086
16:45:39	101,2	100,6	101,0	100,5	-13,086	-12,613	-13,010	-13,147
16:45:54	100,4	100,5	100,2	99,8	-13,834	-13,345	-13,757	-14,017
16:46: 9	100,6	100,3	100,5	99,9	-13,925	-13,422	-13,757	-13,910
16:46:24	100,6	100,1	100,3	100,0	-13,925	-13,422	-13,834	-14,002
16:46:39	100,7	100,1	100,6	100,1	-14,047	-13,605	-13,834	-14,002
16:46:54	100,8	100,5	100,6	100,2	-14,047	-13,605	-13,925	-14,108
16:47: 9	100,8	100,3	100,6	100,2	-14,047	-13,605	-13,925	-14,108
16:47:24	100,7	100,4	100,6	100,3	-14,139	-13,712	-14,002	-14,215
16:47:39	101,0	100,3	100,8	100,4	-14,139	-13,635	-14,078	-14,215
16:47:54	100,8	100,7	100,5	100,2	-14,200	-13,696	-14,078	-14,292
16:48: 9	100,9	100,5	100,8	100,3	-14,200	-13,696	-14,078	-14,292
16:48:24	100,8	100,4	100,7	100,2	-14,353	-13,803	-14,139	-14,292
16:48:39	100,8	100,5	100,8	100,3	-14,353	-13,803	-14,139	-14,368
16:48:54	101,0	100,5	100,8	100,3	-14,276	-13,803	-14,200	-14,368
16:49: 9	100,9	100,4	100,7	100,4	-14,398	-13,864	-14,200	-14,368
16:49:24	101,0	100,6	100,9	100,3	-14,398	-13,864	-14,261	-14,429
16:49:39	101,0	100,6	100,9	100,4	-14,398	-13,925	-14,261	-14,429
16:49:54	100,8	100,4	100,7	100,4	-14,490	-14,002	-14,353	-14,429
16:50: 9	100,9	100,6	100,8	100,4	-14,490	-14,002	-14,353	-14,429
16:50:24	101,1	100,6	100,9	100,4	-14,490	-14,002	-14,353	-14,429
16:50:39	100,9	100,5	101,0	100,4	-14,490	-14,002	-14,353	-14,429
16:50:54	101,1	100,7	101,0	100,3	-14,490	-14,002	-14,429	-14,429
16:51: 9	101,2	100,6	100,9	100,3	-14,490	-14,093	-14,429	-14,429
16:51:24	101,1	100,4	100,9	100,5	-14,582	-14,093	-14,505	-14,521
16:51:39	100,9	101,0	100,9	100,5	-14,688	-14,200	-14,505	-14,521
16:51:54	101,3	100,5	100,8	100,6	-14,688	-14,108	-14,582	-14,627
16:52: 9	101,1	100,9	101,0	100,5	-14,826	-14,246	-14,490	-14,627
16:52:24	101,2	100,7	101,0	100,6	-14,826	-14,246	-14,582	-14,627
16:52:39	101,0	100,8	101,1	100,6	-14,826	-14,337	-14,673	-14,688
16:52:54	100,3	100,9	101,1	100,6	-15,894	-15,436	-14,673	-14,688
16:53: 9	100,4	99,9	100,1	99,8	-15,894	-15,436	-15,741	-16,184
16:53:24	100,6	100,2	100,6	100,3	-15,955	-15,436	-15,741	-16,184
16:53:39	100,8	100,4	100,7	100,2	-15,955	-15,543	-15,848	-16,184
16:53:54	100,8	100,5	100,6	100,2	-16,077	-15,619	-15,924	-16,275

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TED DAVIS-BESSE UNIT NO. 1

GROUP 3 POSTTRIP REVIEW
19:52:23 1/15/1983

1/15/1983

REACTOR PROTECTION SYSTEM (RPS)

TIME	CH1 PR NI6 FLUX% H795	CH2 PR NI5 FLUX% H804	CH3 PR NI8 FLUX% H814	CH4 PR NI7 FLUX% H820	CH1 PR NI6 DFLUX% R794	CH2 PR NI5 DFLUX% R803	CH3 PR NI8 DFLUX% R813	CH4 PR NI7 DFLUX% R819
16:54: 9	100,6	100,4	100,6	100,4	-16,077	-15,619	-15,924	-16,275
16:54:24	100,9	100,6	100,9	100,3	-16,199	-15,619	-15,986	-16,275
16:54:39	101,0	100,6	100,9	100,3	-16,199	-15,680	-15,986	-16,337
16:54:54	101,0	100,5	100,7	100,3	-16,306	-15,680	-16,092	-16,398
16:55: 9	100,9	100,6	100,8	100,5	-16,306	-15,818	-16,092	-16,398
16:55:24	101,1	100,6	101,0	100,5	-16,306	-15,818	-16,184	-16,398
16:55:39	101,0	100,7	101,0	100,5	-16,398	-15,970	-16,184	-16,398
16:55:54	101,0	100,4	100,9	100,6	-16,398	-15,970	-16,275	-16,550
16:56: 9	101,1	100,6	100,7	100,4	-16,474	-15,970	-16,275	-16,550
16:56:24	100,9	100,4	100,8	100,5	-16,535	-16,047	-16,352	-16,550
16:56:39	100,9	100,5	101,0	100,8	-16,535	-16,108	-16,352	-16,550
16:56:54	100,9	100,6	100,8	100,4	-16,535	-16,047	-16,352	-16,550
16:57: 9	100,7	100,6	100,6	100,7	-16,535	-16,123	-16,459	-16,611
16:57:24	100,8	100,4	100,6	100,6	-16,535	-16,123	-16,459	-16,688
16:57:39	101,0	100,4	100,8	100,6	-16,535	-16,214	-16,459	-16,688
16:57:54	100,9	100,5	100,7	100,6	-16,642	-16,214	-16,565	-16,688
16:58: 9	101,1	100,6	100,9	100,4	-16,642	-16,214	-16,565	-16,688
16:58:24	100,4	100,1	100,1	99,8	-17,252	-16,825	-17,054	-17,420
16:58:39	100,7	100,1	100,4	100,3	-17,252	-16,886	-17,161	-17,420
16:58:54	100,7	100,5	100,5	100,3	-17,374	-16,962	-17,267	-17,420
		*****	*****	***** TRIP	*****	*****		
16:59:12	100,7	100,3	100,5	100,2	-17,374	-17,023	-17,267	-17,496
16:59:26	4,3	3,2	100,5	100,5	-0,954	-0,847	-0,893	-17,496
16:59:41	1,9	1,5	3,0	2,4	-0,374	-0,465	-0,572	-0,832
16:59:56	1,1	0,9	1,6	1,2	-0,267	-0,359	-0,481	-0,557
17: 0: 9	0,7	0,9	1,0	0,7	-0,206	-0,298	-0,481	-0,450
17: 0:26	0,5	0,3	0,7	0,3	-0,206	-0,298	-0,420	-0,450
17: 0:39	0,3	0,3	0,4	0,1	-0,130	-0,298	-0,420	-0,389
17: 0:55	0,2	0,0	0,3	0,0	-0,130	-0,237	-0,420	-0,389
17: 1: 9	0,1	0,0	0,2	-0,1	-0,130	-0,237	-0,343	-0,389
17: 1:27	0,1	-0,1	0,1	-0,1	-0,130	-0,237	-0,343	-0,328
17: 1:39	0,1	-0,1	0,1	-0,2	-0,130	-0,237	-0,343	-0,328
17: 1:54	0,0	-0,1	0,0	-0,2	-0,130	-0,237	-0,343	-0,328
17: 2: 9	0,0	-0,1	0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 2:24	0,0	-0,1	0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 2:39	0,0	-0,1	0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 2:54	0,0	-0,1	0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 3: 9	0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 3:24	0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 3:39	0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 3:54	0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328

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TED DAVIS-BESSE UNIT NO. 1

GROUP 3 POSTTRIP REVIEW
19:52:23 1/15/1983

1/15/1983

REACTOR PROTECTION SYSTEM (RPS)

TIME	CH1 PR NI6 FLUX% R795	CH2 PR NI5 FLUX% R804	CH3 PR NI8 FLUX% R814	CH4 PR NI7 FLUX% R820	CH1 PR NI6 DFLUX% R794	CH2 PR NI5 DFLUX% R803	CH3 PR NI8 DFLUX% R813	CH4 PR NI7 DFLUX% R819
17: 4: 9	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 4:25	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 4:39	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 4:54	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 5: 9	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 5:24	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 5:39	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 5:54	-0,0	-0,2	-0,0	-0,3	-0,130	-0,237	-0,343	-0,328
17: 6: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 6:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 6:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 6:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 7: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 7:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 7:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 7:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 8: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 8:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 8:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 8:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 9: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 9:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 9:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17: 9:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:10: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:10:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:10:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:10:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:11: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:11:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:11:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:11:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:12: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:12:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:12:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:12:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:13: 9	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:13:24	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:13:39	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328
17:13:54	-0,0	-0,2	-0,1	-0,3	-0,069	-0,237	-0,343	-0,328

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10:14:16 CONT Q327  EHC PMP DISCH FLT DP                                  NORM
10:14:16 CONT Q418  EMER BUS C1 CTRL PWR                                  NORM
10:14:20 BAD  V661  MFPT 2 BFP END BRG VIB (MILS)          -0.18              0.00
10:14:24 CONT Z464  HP FW HTR 1-6 HI LVL DRN VLV                          CLOS
10:14:26 CONT Q627  MFPT 1 HP OIL PMP 2                                   ON
10:14:29 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:14:30 NORM P931  SG 1 OUT STM PRESS,PT12B1             901.06            901.93
10:14:43 NORM T968  DEAR HTR 1 TERM TEMP DIFF               0.16              3.00
10:14:48 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:14:58 CONT Q905  SFAS CTMT AIR CLR LOGIC L223                          TRIP
10:14:59 CONT L762  RC MU TK LVL,MU16-2                                   HILO
10:14:59 FLAG X258  SFAS EMER PWR LOGIC L263                              TRIP
10:15: 1 CONT L760  RC MU TK LVL,MU16-1                                   HILO
10:15:09 CONT Q905  SFAS CTMT AIR CLR LOGIC L223                          NORM
10:15:10 CONT Z732  RC DIVERTING VLV OPEN TO MU TK                        NO
10:15:10 CONT Q001  ARTS IN FROM MFPT                                     TRIP
10:15:12 LOW  A864  RPS CH 3 IR SU RATE DM14 (DPM)         -0.11              0.00
10:15:17 HIGH L761  RC MU TK LVL,MU16-1 (IN)               85.71             81.00
10:15:18 CONT Z733  RC DIVERTING VLV OPEN TO WD SYS                       CLOS
10:15:20 NORM V661  MFPT 2 BFP END BRG VIB (MILS)          -0.17              2.00
10:15:23 CONT L760  RC MU TK LVL,MU16-1                                   NORM
10:15:27 CONT L762  RC MU TK LVL,MU16-2                                   NORM
CURRENT DATE IS: OCT., 19  1983
10:15:43 NORM A871  RPS CH 4 IR SU RATE DM13 (DPM)          0.14              1.00
10:15:46 CONT Q853  SFAS CC WTR LOGIC L233                                TRIP
10:15:58 CONT Q853  SFAS CC WTR LOGIC L233                                NORM
10:16:02 NORM L761  RC MU TK LVL,MU16-1 (IN)               84.73             88.00
10:16: 6 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:16:13 NORM A864  RPS CH 3 IR SU RATE DM14 (DPM)          0.13              1.00
10:16:27 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:16:35 CONT Z464  HP FW HTR 1-6 HI LVL DRN VLV                          NC
10:16:43 LOW  T968  DEAR HTR 1 TERM TEMP DIFF              -0.03              0.00
10:16:43 LOW  A871  RPS CH 4 IR SU RATE DM13 (DPM)         -0.12              0.00
10:16:58 CONT Q953  SFAS SW LOGIC L243                                    TRIP
10:17:12 LOW  A864  RPS CH 3 IR SU RATE DM14 (DPM)         -0.10              0.00
10:17:13 CONT Q953  SFAS SW LOGIC L243                                    NORM
10:17:16 CONT Q001  ARTS IN FROM MFPT                                     NORM
10:17:20 BAD  V661  MFPT 2 BFP END BRG VIB (MILS)          -0.18              0.00
10:17:24 CONT Q004  ARTS TEST TRIP                                        NORM
10:17:28 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:17:43 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:17:43 NORM T968  DEAR HTR 1 TERM TEMP DIFF               0.06              3.00
10:17:43 NORM A871  RPS CH 4 IR SU RATE DM13 (DPM)          0.10              1.00
10:17:50 NORM V661  MFPT 2 BFP END BRG VIB (MILS)          -0.18              2.00
10:18: 4 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:18:15 HIGH P931  SG 1 OUT STM PRESS,PT12B1             902.89            901.91
10:18:19 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:18:24 CONT Z464  HP FW HTR 1-6 HI LVL DRN VLV                          CLOS
10:18:25 CONT Q901  SFAS CS VLV LOGIC L253                                TRIP
10:18:26 FLAG X306  SFAS CTMT ISO 3 LOGIC L423                            TRIP
10:18:30 NORM P931  SG 1 OUT STM PRESS,PT12B1             899.80            901.91
10:18:40 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:18:42 NORM A864  RPS CH 3 IR SU RATE DM14 (DPM)          0.12              1.00
10:18:43 LOW  A871  RPS CH 4 IR SU RATE DM13 (DPM)         -0.01              0.00
10:18:43 CONT Q901  SFAS CS VLV LOGIC L253                                NORM
10:18:54 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:19:13 CONT L466  HP FW HTR 2-4 LVL                                     HIGH
10:19:13 CONT Q929  SFAS EMER PWR LOGIC L263                              TRIP
10:19:14 CONT Q004  ARTS TEST TRIP                                        BYPS
10:19:14 FLAG Q072  CTMT H2 DILUTN OUT ISO VLV, 5038                      NC
10:19:24 FLAG Q072  CTMT H2 DILUTN OUT ISO VLV, 5038                      NORM
10:19:30 CONT L466  HP FW HTR 2-4 LVL                                     NORM
10:19:36 LOW  P637  HFP 1 DISCH PRESS                      44.01            900.00
10:19:42 LOW  A864  RPS CH 3 IR SU RATE DM14 (DPM)         -0.08              0.00
10:20:13 NORM A871  RPS CH 4 IR SU RATE DM13 (DPM)          0.07              1.00
10:20:20 BAD  V661  MFPT 2 BFP END BRG VIB (MILS)          -0.17              0.00
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DATA ACQUISITION AND DISPLAY SYSTEM RECORDED POINTS

Auxiliary Feedwater Flow to Steam Generator (SG) 1 (typical SGs 1 and 2)

Auxiliary Feed Pump 1 Discharge Pressure (typical Pumps 1 and 2)

Auxiliary Feed Pump Turbine 1 Speed (typical Pumps 1 and 2)

Containment Hydrogen Concentration

Containment Spray Pump 1 Discharge Flow (typical Pumps 1 and 2)

Containment Normal Sump Level

Containment Wide Range Level

Containment Wide Range Pressure

Containment Atmosphere Particulate Radiation

Containment Atmosphere Iodine Radiation

Containment Atmosphere Noble Gas Radiation

Containment Atmosphere Noble Gas Mid to High Range Radiation

Containment Wide Range Radiation

Unit Vent Particulate Radiation

Unit Vent Iodine 131 Radiation

Unit Vent Xenon 133 Radiation

Generator Gross Megawatts

High Pressure Injection 1-1 Flow (typical Lines 1-1, 1-2, 2-1, and 2-2)

Incore Outlet Temperature (typical 16 sensors)

Low Pressure Injection Pump 1 Flow (typical Pumps 1 and 2)

Main Feedwater Temperature to Integrated Control System

Main Feedwater Control Valve Position Loop 1 (typical Loops 1 and 2)

Main Feedwater Startup Control Valve Position Loop 1 (typical Loops 1 and 2)

Main Feedwater Compensated Flow Loop 1 (typical Loops 1 and 2)

Reactor Coolant Makeup Tank Level

Reactor Coolant System (RCS) Hot Leg Flow Loop 1 (Loops 1 and 2)

RCS Pressurizer Compensated Level

RCS Pressurizer Quench Tank Level

RCS Pressurizer Quench Tank Pressure

RCS Hot Leg Wide Range Pressure Loop 1 (typical Loops 1 and 2)

RCS Average Narrow Range Temperature

RCS Calculated Hot Leg Subcooled Margin Channel A

RCS Calculated Hot Leg Subcooled Margin Channel B

RCS Hot Leg Wide Range Temperature Loop 1 (typical Loops 1 and 2)

RCS Pressurizer Temperature

RCS Pressurizer Power Operated Relief Valve Position

RCS Pressurizer Pressure Relief Valve Position (typical Valves 1 and 2)

Reactor Coolant Pump (RCP) 1-1 Discharge Cold Leg Wide Range Temperature (typical RCPs 1-1, 1-2, 2-1, and 2-2)

Reactor Protection System (RPS) Auctioneered Average Power

RPS Channel 1 Power Range Flux (typical Channels 1 through 4)

RPS Channel 1 Source Range Flux (typical Channels 1 and 2)

RPS Channel 3 Intermediate Range Flux (typical Channels 3 and 4)

Safety Features Actuation System (SFAS) Channel 1 Borated Water Storage Tank Level

Steam Generator (SG) 1 Outlet Steam Temperature (typical SGs 1 and 2)

SG 1 Operate Level (typical SGs 1 and 2)

SG 1 Startup Range Level (typical SGs 1 and 2)

SG 1 Outlet Pressure (typical SGs 1 and 2)

SOE POINT INDEX

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
A850	QS-RC1-1	RPS CH 1 Flux-DFlux-Flow BSTBL	-32.25% ± 0.25%	RPS CH 1 $\phi/\Delta\phi$/Flow Trip
A851	QS-NI6	RPS CH 1 HI Flux/No RCP ON BSTBL	1. One pump operating in each loop $\leq$ 54.25 ± .25% of RTP 2. Two pumps operating in one loop and no pump operating in other loop, no pumps operating, or only one pump operating $\leq$ 0.0% of RTP	RPS CH 1 Power/Pumps Trip Bistables trips
A852	QS-RC2B2	RPS CH 1 RC Press-Temp BSTBL	12.6 T/Hot -5644 PSIG ± 4.0 PSI	RPS CH 1 RC Press-Temp Trip
A856	QS-RC1-2	RPS CH 2 Flux-DFlux-Flow BSTBL	-13.57% ± 0.12%	RPS CH 2 $\phi/\Delta\phi$/Flow Trip
A857	QS-NI5	RPS CH 2 HI Flux/No RCP ON BSTBL	1. One pump operating in each loop $\leq$ 54.25 ± .25% of RTP 2. Two pumps operating in one loop and no pump operating in other loop, no pumps operating, or only one pump operating $\leq$ 0.0% of RTP	RPS CH 2 Power/Pumps Trip Bistables trips
A858	QS-RC2A2	RPS CH 2 RC Press-Temp BSTBL	12.6 T/Hot -5644 PSIG ± 4.0 PSI	RPS CH 2 RC Press-Temp. Trip
A862	QS-RC1-3	RPS CH 3 Flux-DFlux-Flow BSTBL	7.86% ± 0.14%	RPS CH3 $\phi/\Delta\phi$/Flow Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
A863	QS-NI8	RPS CH 3 HI Flux/No RCP ON BSTBL	1. One pump operating in each loop ≤ 54.25 ± .25% of RTP 2. Two pumps operating in one loop and no pump operating in other loop, no pumps operating, or only one pump operating ≤ 0.0% of RTP	RPS CH 3 Power/Pumps Trip Bistables trips
A865	QS-RC2B1	RPS CH 3 RC Press-Temp BSTBL	12.6 T/Hot - 5644 PSIG ± 4.0 PSI	RPS CH 3 RC Press-Temp Trip
A869	QS-RC1-4	RPS CH 4 Flux-DFlux-Flow BSTBL	32.25% ± 0.25%	RPS CH 4 $\phi/\Delta\phi$/Flow Trip
A870	QS-NI7	RPS CH 4 HI Flux/No RCP ON BSTBL	1. One pump operating in each loop ≤ 54.25 ± .25% of RTP 2. Two pumps operating in one loop and no pump operating in other loop, no pumps operating, or only one pump operating ≤ 0.0% of RTP	RPS CH 4 Power/Pumps Trip Bistables trips
A872	QS-RCA1	RPS CH 4 RC Press-Temp BSTBL	12.6 T/Hot -5644 PSIG ± 4.0 PSI	RPS CH 4 RC Press-Temp Trip
I061	IS-6500	Bus A Elec Fault	N/A	Over current condition on the 13.8 KV Bus A or a ground fault on the 13.8 KV Bus A
I069	IS-65001	Bus B Elec Fault	N/A	Over current on the 13.8 KV Bus B or a ground fault on the 13.8 KV Bus B

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
I421	IDS-6400	GEN DIFF	1500 primary amperes (main transformer high side amperes)	An unbalance of current flowing into and out of the generator windings. Trips turbine and main generator breakers 34560 and 34561.
I425	IS-64006	GEN Ground Current	Relay alarms for generator neutral current of 0.853 primary ampers or more up to a maximum of 7.4 primary ampers for a solid ground on the generator 25,000 volt terminals	The alarm is caused by the flow of ground fault current in the generator neutral when it reaches a preset limit due to a ground fault in the stator or on the generator 25,000 volt leads.
I426	IDS-6405	GEN & MN XFMR Overall Diff Trip	346 primary ampers (main transformer high side amperes)	A quantitative difference of currents flowing in the generator stator windings, the two 345 KV air circuit breakers, main transformer and #11 Auxiliary Transformer. Trips turbine and main generator breakers 34560 and 34561.
I427	KS-6400B	GEN Negative Phase Seq	Negative Phase Sequence Relay: Alarms for a negative phase sequence pickup current of 1575 primary amperes (main transformer high side amperes)	When poly phase currents are unbalanced or contain negative phase sequence components above a given amount. Trips generator main breakers 34560 and 34561 for generator negative phase sequence protection.
I428	IS-6400A	GEN Overcurrent	1. With voltage restraint: 50,000 primary amperes (main transformer high side ampers) 2. Zero voltage restraint: 12,500 primary ampers (main transformer high side ampers)	The current in the turbine generator circuit has reached a predetermined value for system fault backup protection. Trips generator main breakers 34560 and 34561 for generator overcurrent protection.

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
I844	IS-6108	SWYD Bus J Diff	N/A	Bus J Elect Fault
J428	JS-6400A	GEN Reverse Pwr	At ≥5,200 KW in, relay times out for 25 seconds and then initiates trip	Motoring occurs as a result of a deficiency in the prime mover input to the a-c generator. When this input cannot supply all the losses, then the deficiency is supplied by absorbing real power from the system. Trips turbine and main generator breakers 34560 and 34561.
L680	LSH-140	MSR 1 HI Lvl Trub Trip	Lvl increases to 3"-5" from bottom of tank	Increasing level in MSR drain line
L690	LSH-164	MSR 2 HI Lvl Turb Trip	Lvl increases to 3"-5" from bottom of tank	Increasing level in MSR drain line
L770	LSLL-RC14	RC PRZR Lo Lvl Htr	40 inches	Low pressurizer level
L862	QS-7640	SFAS Sump Recirc Logic L511	8 feet water	This alarm is generated when any two of the four SFAS BWST low level bistables trip. The alarm is provided to tell when SFAS level 5 allows the transfer to the emergency sump to occur.
L864	QS-7641	SFAS Sump Recirc Logic L512	8 feet water	This alarm is generated when any two of the four SFAS BWST low level bistables trip. The alarm is provided to tell when SFAS level 5 allows the transfer to the emergency sump to occur.

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POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
L866	QS-7642	SFAS Sump Recirc Logic L513	8 feet water	This alarm is generated when any two of the four SFAS BWST low level bistables trip. The alarm is provided to tell when SFAS level 5 allows the transfer to the emergency sump to occur.
L868	QS-7642	SFAS Sump Recirc Logic L514	8 feet water	This alarm is generated when any two of the four SFAS BWST low level bistables trip. The alarm is provided to tell when SFAS level 5 allows the transfer to the emergency sump to occur.
P683	PSH-6405	MN XFMR 1 Sudden Press	N/A	The alarm is caused by a sudden change in XFMR Tank pressure, possibly accompanied by an arc in the XFMR. The turbine generator and reactor may trip.
P701	QS-2686	SFRCS DP Half/Full Trip, SG 1	177 PSIG	High steam to feedwater DP
P702	QS-2685	SFRCS DP Half/Full Trip, SG 2	177 PSIG	High steam to feedwater DP
P857	PS-NI15-2	RPS CH 1 CTMT HI Press	3.175 PSIG ± 0.2 PSIG	RPS CH 1 CTMT Press HI Trip
P858	PSh-RC2B2	RPS CH 1 RC HI Press	2285.0 PSIG ± 4.0 PSIG	RPS CH 1 RC Press HI Trip
P859	PSL-RC2B2	RPS CH 1 RC LO Press BSTBL	1998.4 PSIG ± 4.0 PSIG	RPS CH 1 RC Press Low Trip
P862	PS-NI15-1	RPS CH 2 CTMT HI Press	3.175 PSIG ± 0.2 PSIG	RPS CH 2 CTMT Press HI Trip
P863	PSL-RC2A2	RPS CH 2 RC LO Press BSTBL	1998.4 PSIG ± 4.0 PSIG	RPS CH 2 RC Press Low Trip
P864	PSH-RC2A2	RPS CH 2 RC HI Press	2285.0 PSIG ± 4.0 PSIG	RPS CH 2 RC Press HI Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
P867	PS-NI15-4	RPS CH 3 CTMT HI Press	3.175 PSIG ± 0.2 PSIG	RPS CH 3 CTMT Press HI Trip
P868	PSH-RC2B1	RPS CH 3 RC HI Press	2285.0 PSIG ± 4.0 PSIG	RPS CH 3 RC Press HI Trip
P869	PSL-RC2B1	RPS CH 3 RC LO Press BSTBL	1998.4 PSIG ± 4.0 PSIG	RPS CH 3 RC Press Low Trip
P872	PS-NI15-3	RPS CH 4 CTMT HI Press	3.175 PSIG ± 0.2 PSIG	RPS CH 4 CTMT Press HI Trip
P873	PSH-RC2A1	RPS CH 4 RC HI Press	2285.0 PSIG ± 4.0 PSIG	RPS CH 4 RC Press HI Trip
P874	PSL-RC2A1	RPS CH 4 RC LO Press BSTBL	1998.4 PSIG ± 4.0 PSIG	RPS CH 4 RC Press Low Trip
P895	PSHH-2000A	SFAS CH 1 CTMT Press > 38.4 PSIA	23.6 PSIG ± 0.4 PSIG	SFAS CH 1 CTMT Press HI HI Trip
P896	PSH-2000A	SFAS CH 1 CTMT Press > 18.4 PSIA	3.5 PSIG ± 0.5 PSIG	SFAS CH 1 CTMT Press HI Trip
P898	PSHH-2001A	SFAS CH 2 CTMT Press > 38.4 PSIA	23.6 PSIG ± 0.4 PSIG	SFAS CH 2 CTMT Press HI HI Trip
P899	PSH-2001A	SFAS CH 2 CTMT Press > 18.4 PSIA	3.5 PSIG ± 0.5 PSIG	SFAS CH 2 CTMT Press HI Trip
P901	PSHH-2002A	SFAS CH 3 CTMT Press > 38.4 PSIA	23.6 PSIG ± 0.4 PSIG	SFAS CH 3 CTMT Press HI HI Trip
P902	PSH-2002A	SFAS CH 3 CTMT Press > 18.4 PSIA	3.5 PSIG ± 0.5 PSIG	SFAS CH 3 CTMT Press HI Trip
P904	PSHH-2003A	SFAS CH 4 CTMT Press > 38.4 PSIA	23.6 PSIG ± 0.4 PSIG	SFAS CH 4 CTMT Press HI HI Trip
P905	PSH-2003A	SFAS CH 4 CTMT Press > 18.4 PSIA	3.5 PSIG ± 0.5 PSIG	SFAS CH 4 CTMT Press HI Trip
P911	PSL-RC2B4	SFAS CH 1 RC < 1650#	1650.0 PSIG ± 25 PSIG	SFAS CH 1 RC Press Low Trip
P912	PSLL-RC2B4	SFAS CH 1 RC < 400#	450 PSIG ± 25 PSIG	SFAS CH 1 RC Press Low Trip
P914	PSL-RC2A4	SFAS CH 2 RC < 1650#	1650.0 PSIG ± 25 PSIG	SFAS CH 2 RC Press Low Trip
P915	PSLL-RC2A4	SFAS CH 2 RC < 400#	450 PSIG ± 25 PSIG	SFAS CH 2 RC Press Low Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
P917	PSL-RC2B3	SFAS CH 3 RC < 1650#	1650 PSIG ± 25 PSIG	SFAS CH 3 RC Press Low Trip
P918	PSLL-RC2B3	SFAS CH 3 RC < 400#	450 PSIG ± 25 PSIG	SFAS CH 3 RC Press Low Trip
P920	PSL-RC2A3	SFAS CH 4 RC < 1650#	1650 PSIG ± 25 PSIG	SFAS CH 4 RC Press Low Trip
P921	PSLL-RC2A3	SFAS CH 4 RC < 400#	450 PSIG ± 25 PSIG	SFAS CH 4 RC Press Low Trip
Q015	QS-6411	Aux XFMR 11 TRBL	N/A	1. A sudden pressure in the XFMR due to a fault 2. A ground fault on the XFMR secondary, or in backup protection breakers HX11A and HX11B 3. A phase overcurrent on the XFMR primary, or in backup protection breakers HX11B and HX11B 4. A differential relay operation caused by a fault in the transformer or its connections to the 13.8 KV buses
Q037	IS-6503	Bus A to XFMR AC BRKR	N/A	1. A bus lockout on Bus A. 2. A primary or secondary ground fault on XFMR AC. 3. A differential or overcurrent on XFMR AC.
Q041	IS-6504	Bus B to XFMR BD BRKR	N/A	1. A bus lockout on Bus B. 2. A primary or secondary ground fault on XFRM BD. 3. A differential or overcurrent on XFMR BD.
Q050	IS-6521	Bus C2 TRBL	N/A	Bus overcurrent sensed by the partial differential overcurrent or ground relay scheme

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q058	IS-6522	Bus D2 TRBL	N/A	Bus overcurrent sensed by the partial differential overcurrent or ground relay scheme
Q180	CRD-SW9	CRD CH A/C Any Trip Device	N/A	1. Breakers A or C Trip 2. Electronic Trip C 3. WYE Current Sensor A 4. Return SCR Trip C
Q181	CRD-SW10	CRD CH B/D Any Trip Device	N/A	1. Breakers B or D Trip 2. Electronic Trip D 3. WYE Current Sensor B 4. Return SCR Trip D
Q266	CRD-SW4	CRD Trip Confirm	N/A	Any reactor trip
Q396	QS-6221A	EMER DG 1 Locked Out or TRBL	N/A	1. Lockout Relay 86-1 operation (will trip AC 101 breaker and short the field for No. 1-1 DG) 2. Lockout Relay 86-2 operation (will trip AC 101 breaker and shutdown the engine) 3. Emergency Diesel Generator Voltage Regulator Switch in the OFF position
Q401	QS-6231A	EMER DG 2 Locked Out or TRBL	N/A	1. Lockout Relay 86-1 operation (will trip AD 101 breaker and short the field for No. 1-2 DG) 2. Lockout Relay 86-2 operation (will trip AD 101 breaker and shutdown the engine) 3. Emergency Diesel Generator Voltage Regulator Switch in the off position.

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q414	IS-6519	ESSEN Bus C1 TRBL	N/A	1. Phase overcurrent on Bus C1 2. Ground overcurrent on Bus C1
Q417	IS-6520	ESSEN Bus D1 TRBL	N/A	1. Phase overcurrent on Bus D1 2. Ground overcurrent on Bus D1
Q430	IS-6529	ESSEN XFMR CE1-1 TRBL	N/A	Automatic tripping of 4.16 KV Feeder Breaker AC1CE11 for the following: 1. Transformer Ground (51N/1CE) 2. Bus Overcurrent (94-1) 3. Feeder Overcurrent (50-51) 4. Feeder Ground (50GS)
Q432	IS-6530	ESSEN XFMR DF1-1 TRBL	N/A	Automatic tripping of 4.16 KV Feeder Breaker AD1DF11 for essential Unit Substation F1 and 480V breaker BDF11 for the following: 1. Transformer Ground (51N/1DF) 2. Bus Overcurrent (94-1) 3. Feeder Overcurrent (50-51) 4. Feeder Ground (50GS)
Q435	IS-6532	ESSEN XFMR CE1-2 TRBL	N/A	Automatic tripping of 4.16 KV Feeder Breaker AC1CE12 for essential Unit Substation F1 and 480V breaker BCE12 for the following: 1. Transformer Ground (51N/2CE) 2. Bus Overcurrent (94-1) 3. Feeder Overcurrent (50-51) 4. Feeder Ground (50GS)

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q437	IS-6532	ESSEN XFMR DF1-2 TRBL	N/A	Automatic tripping of 4.16 KV Feeder Breaker AD1DF12 for essential Unit Substation F1 and 480V breaker BDF12 for the following: 1. Transformer Ground (51N/2DF) 2. Bus Overcurrent (94-1) 3. Feeder Overcurrent (50-51) 4. Feeder Ground (50GS)
Q448	ES-6400A	GEN Field Failure	A typical alarm point is 632,310 KVA power flow into the generator	Loss of excitation by an abnormally low value or failure of generator field current, which causes reactive power flow from the system into the machine. Trips turbine and main generator breakers 34560 and 34561.
Q451	KS-6400A	GEN Out-Of-Step	Gen. Out of step relay: Alarms at a pickup of 0.162 primary ohms and 30,000 primary amperes (main transformer high side ampers).	A phase angle measuring device that functions between two voltages, two currents or between voltage and current. Trips generator main breakers 34560 and 34561 for generator loss of synchronism.
Q613	QS-2731	MFPT 1	1. 5925 RPM 2. 40 PSIG 3. 4 PSIG 4. 4 PSIG 5. 12.5" HgA 6. N/A 7. 1500 PSIG	1. MFPT 1-1 Over Speed Trip 2. MFPT 1-1 Thrust Brg Wear Trip 3. MFPT 1-1 Lube Oil Low Press Trip 4. MFP 1-1 Lube Oil Low Press Trip 5. MFPT 1-1 Exhaust HI Press Trip 6. MFPT 1-1 Manual Trip 7. MFPT 1-1 Disch HI Press Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q634	QS-2732	MFPT 2	1. 5925 RPM 2. 40 PSIG 3. 4 PSIG 4. 4 PSIG 5. 12.5" HgA 6. N/A 7. 1500 PSIG	1. MFPT 1-2 Over Speed Trip 2. MFPT 1-2 Thrust Brg Wear Trip 3. MFPT 1-2 Lube Oil Low Press Trip 4. MFP 1-2 Lube Oil Low Press Trip 5. MFPT 1-2 Exhaust HI Press Trip 6. MFPT 1-2 Manual Trip 7. MFPT 1-2 Disch HI Press Trip
Q783	QS-6515A	RCP 1-1 MTR TRBL	N/A	1. Motor Overcurrent a. Phase, Time and Instantaneous b. Phase, Extremely Inverse Time 2. Instantaneous Ground Fault 3. Phase Imbalance 4. Bus Protection Lockout
Q789	QS-6516A	RCP 1-2 MTR TRBL	N/A	1. Motor Overcurrents a. Phase, Time and Instantaneous b. Phase, Extremely Inverse Time 2. Instantaneous Ground Fault 3. Phase Imbalance 4. Bus Protection Lockout
Q795	QS-6517A	RCP 2-1 MTR TRBL	N/A	1. Motor Overcurrents a. Phase, Time and Instantaneous b. Phase, Extremely Inverse Time 2. Instantaneous Ground Fault 3. Phase Imbalance 4. Bus Protection Lockout

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q801	QS-6518A	RCP 2-2 MTR TRBL	N/A	1. Motor Overcurrents a. Phase, Time and Instantaneous b. Phase, Extremely Inverse Time 2. Instantaneous Ground Fault 3. Phase Imbalance 4. Bus Protection Lockout
Q810	RPS-TR-B	RPS CH 1 CH Trip	N/A	When the channel trip relay in the RPS Channel 1 Reactor Trip Module is deenergized
Q818	RPS-TR-A	RPS CH 2 CH Trip	N/A	When the channel trip relay in the RPS Channel 2 Reactor Trip Module is deenergized
Q822	RPS-SHBHP	RPS Shutdown Bypass High Press	1820 PSIG (+0, -1.6 PSIG)	When a channel is in shutdown bypass and the RPS Shutdown Bypass High Pressure Bistable trips
Q826	RPS-TR-D	RPS CH 3 CH Trip	N/A	When the channel trip relay in the RPS CH 3 Reactor Trip Module is deenergized
Q834	RPS-TR-C	RPS CH 4 CH Trip	N/A	When the channel trip relay in the CH 4 Reactor Trip Module is deenergized
Q841	RPS-SRI	RPS SU Rate Rod WTHDRWL INHIBIT	1. $\geq$ 2 DPM in the Source Range (NI 1, 2) with reactor power less than $1x10^{-9}$ amps on the Intermediate Range (NI 3,4). 2. $\geq$ 3 DPM on the Intermediate Range (NI 3, 4) with reactor power less than 10% on the Power Range (NI 5, 6, 7, 8).	When the control rods are inhibited from being withdrawn by the Nuclear Instrumentation

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Q963	QS-SFRCS	SFRCS Full Trip	1. High or low current indication on all 4 RCP's. 2. Less than 612 PSIG. 3. Greater than 177 PSIG. 4. Less than 26.5"	1. Loss of 4 Reactor Coolant Pumps. 2. Low steam header pressure. 3. High steam to feedwater DP due to loss of feedwater. 4. Low steam generator level.
Q981	QS-6401	SU XFMR 01 TRBL	1. Sudden Pressure 8 PSIG 2. Phase overcurrent 144.3 A (86.2 MVA)	1. A sudden pressure in the XFMR due to a fault (AP3101.07) 2. A ground fault on the XFMR secondary or backup protection for breakers HX01A and HX01B 3. A phase overcurrent on the XFMR primary or backup protection for breakers HX01A and HX01B 4. A differential relay operation caused by a fault in the transformer or its connections to the 13.8 KV Busses
Q984	QS-6402	SU XFMR 02 TRBL	1. Sudden Pressure 8 PSIG 2. Phase overcurrent 144.3 A (86.2 MVA)	1. A sudden pressure in the XFMR due to a fault (AP3101.07) 2. A ground fault on the XFMR secondary or backup protection for breakers HX02A and HX02B 3. A phase overcurrent on the XFMR primary or backup protection for breakers HX02A and HX02B 4. A differential relay operation caused by a fault in the transformer or its connections to the 13.8 KV Busses

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
R793	NSH-NI5	RPS CH 1 HI Flux	1. 104.75 + 0 - .5% of Rated Thermal Power with four pumps operating 2. 79 + 0 - .5% of Rated Thermal Power with three pumps operating	When any one of the four RPS Over-power Trip Bistables Trip
R802	NSH-NI5	RPS CH 2 HI Flux	1. 104.75 + 0 - .5% of Rated Thermal Power with four pumps operating 2. 79 + 0 - .5% of Rated Thermal Power with three pumps operating	When any one of the four RPS Over-power Trip Bistables Trip
R811	NSH-NI8	RPS CH 3 HI Flux	1. 104.75 + 0 - .5% of Rated Thermal Power with four pumps operating 2. 79 + 0 - .5% of Rated Thermal Power with three pumps operating	When any one of the four RPS Over-power Trip Bistables Trip
R817	NSH-NI7	RPS CH 4 HI Flux	1. 104.75 + 0 - .5% of Rated Thermal Power with four pumps operating 2. 79 + 0 - .5% of Rated Thermal Power with three pumps operating	When any one of the four RPS Over-power Trip Bistables Trip
R832	RSHH-2004	SFAS CH 1 CTMT RAD HI	1. Modes 1, 2, 3, 4: 15 MR/HR or 1.8 x BKGND ± 10% BKGND 2. Mode 6: 2 MR/HR	SFAS CH 1 CTMT RAD HI Trip
R834	RSHH-2005	SFAS CH 2 CTMT RAD HI	1. Modes 1, 2, 3, 4: 25 MR/HR or 1.8 x BKGND ± 10% BKGND 2. Mode 6: 2 MR/HR	SFAS CH 2 CTMT RAD HI Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
R836	RSHH-2006	SFAS CH 3 CTMT RAD HI	1. Modes 1, 2, 3, 4: 25 MR/HR or 1.8 x BKGND ± 10% BKGND 2. Mode 6: 2 MR/HR	SFAS CH 3 CTMT RAD HI Trip
R838	RSHH-2007	SFAS CH 4 CTMT RAD HI	1. Modes 1, 2, 3, 4: 15 MR/HR or 1.8 x BKGND ± 10% BKGND 2. Mode 6: 2 MR/HR	SFAS CH 4 CTMT RAD HI Trip
S426	SSL-6400	GEN Under Frequency	Under frequency relay 81U1 & 81U2 are set for 58.2 Hz and 0.5 seconds. Both contacts are in series so that both under frequency relays must operate to trip.	When the system load exceeds system generation. Trips generator main breakers 34560 and 34561 for generator under frequency protection.
T856	TSH-RC3B2	RPS CH 1 RC HI Temp	616.8 °F ± 0.2 °F	RPS CH 1 RC Temp HI Trip
T857	TSH-RC3A4	RPS CH 2 RC HI Temp	616.8 °F ± 0.2 °F	RPS CH 2 RC Temp HI Trip
T858	TSH-RC3B4	RPS CH 3 RC HI Temp	616.8 °F ± 0.2 °F	RPS CH 3 RC Temp HI Trip
T859	TSH-RC3A2	RPS CH 4 RC HI Temp	616.8 °F ± 0.2 °F	RPS CH 4 RC Temp HI Trip
X014	QS-6044	SWYD ACB 34563	N/A	SWYD ACB 34563 Trip
X015	QS-6045	SWYD ACB 34564	N/A	SWYD ACB 34564 Trip
X024	QS-6117B	SWYD Oscillograph Started	N/A	Electrical fault on 345 KV lines (may also be caused by operating 345 KV breakers).
X025	QS-6041	SWYD ACB 34561	N/A	ACB 34560 Trip
X026	QS-6042	SWYD ACB 34561	N/A	ACB 34561 Trip
X027	QS-6043	SWYD ACB 34562	N/A	SWYD ACB Trip

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
X030	QS-2210	T-G Master Trip Solenoids	N/A	When one or both master trip solenoids are deenergized
X032	QS-2213	T-G Mech Trip VLV	Overspeed trip of 110% (1980 RPM)	1. Excessive turbine generator speed 2. Manual mechanical trip actuated (frount standard) 3. Mechanical trip solenoid energized by one of the following: a. Control Room EHC trip button b. Master trip solenoid valve tripped
X033	ZS-2211	T-G Mech Trip Solenoid Trub Trip	N/A	Energizing the mechanical trip Solenoid
X038	QS-2293A	T-G Master Turb Trip	Turbine master trip buss energized	Turbine tripped
Y060	ZS-SP13B1	Turb Bypass VLV 1-1	N/A	When the valve changes position Clos/NC
Y061	ZS-SP13B2	Turb Bypass VLV 1-2	N/A	When the valve changes position Clos/NC
Y062	ZS-SP13B3	Turb Bypass VLV 1-3	N/A	When the valve changes position Clos/NC
Y063	ZS-SP13A1	Turb Bypass VLV 2-1	N/A	When the valve changes position Clos/NC
Y064	ZS-SP13A2	Turb Bypass VLV 2-2	N/A	When the valve changes position Clos/NC

POINT NO.	INSTR. NO.	DESCRIPTOR	SET POINT	ALARM CONDITION(S)
Y065	ZS-SP13A3	Turb Bypass VLV 2-3	N/A	When the valve changes position Clos/NC
Z980	ZS-2957	Unit Seismic Instr	0.1 g	1. Seismic Event 2. Blasting

SOE/ALARM ANALYSIS

If Reactor Protection System (RPS) Trip:

(1) Each channel has SOE points on both the trip parameter and the verification of a channel trip. Check both.

(2) Verify on SOE, when second channel tripped, the following was received indicating trip occurred:

Q180 "CRD CH A/C ANY TRIP DEVICE"	"TRIP"
Q181 "CRD CH B/D ANY TRIP DEVICE"	"TRIP"
Q266 "CRD TRIP CONFIRM"	"TRIP"

(3) Verify the trip parameter makes sense; for example, you should not get a pressure temperature trip when T_{hot} is less than 606°F.

(4) On SOE after the trip depressurizes the primary, all four RPS channels should receive low pressure trips. This is the time to confirm which RPS channels had not tripped (the channel trip only comes in once on SOE).

(5) On alarms, verify:

Q185 "CRD MTR PWR"	"OFF"
Q186 "CRD PROGRAMMER LAMP FAULT"	"YES"

Check Turbine Generator:

(1) On SOE verify:

X030 "T/G MASTER TRIP SOLENOIDS"	"TRIP"]	
J428 "GEN REVERSE POWER"	"TRIP"]	after
X025 "SWYD ACB 34560"	"OPEN"]	30
X026 "SWYD ACB 34561"	"OPEN"]	seconds

(2) On alarm printout verify:

Z498 - Z501	"HPT GOV VLV 1-4"	"CLOSED"
Z506, Z508	"HPT STOP VLV 1-4"	"CLOSED"
Z510, Z512,] Z591, Z576,] Z578, Z593]	- "LPT 1, 2 RHT STOP VLVS 1-4"	"CLOSED"
Z580, Z581,] Z594, Z596,]	- "LPT 1, 2 RIV 1-4"	"CLOSED"
X070	"TURB EXT AIR DUMP RELAY VLV"	"TRIP"
Q379	"EHC ELECTRICAL"	"TRBL"

Primary

(1) On alarms, check time of second makeup pump on
    Q754 <u>or</u> Q759 "RC MU PMP 1 (2)" "ON"

(2) On alarms, check high makeup
    F741 "RC MU FLOW" "HIGH"

(3) On SOE, check pressurizer heater cutoff if < 40"
    L770 "RC PRZR LO LVL HTR" "TRIP"

Then return to normal

Miscellaneous

(1) On alarms, check atmospheric vent positions
    Z961 and Z969 "SG 1, 2 ATM STM VENT VLV" "OPEN" when > 1025 PSIG

(2) On SOE or alarms, check TBV positions
    Y060, Y065 "TURB BYPASS VALVE 1, 2 - 1-3" "NC" when > 1015 PSIG

(3) On alarms, check for deaerator hi level trips
    L359, L360 "DEAR STRG TK 1, 2 HI LVL" "TRIP"

(4) On alarms, check condensate pumps reduction
    Q168, Q171, Q174 "CNDS PMP 1, 2, 3" "OFF"

SFRCS

Presently, only three SFRCS inputs are connected to the SOE monitor; these are:

Point 40	SFRCS Full Trip
Point 62	SFRCS DP Half/Full Trip SG 1
Point 63	SFRCS DP Half/Full Trip SG 2

The only way to tell the input parameter on which SFRCS tripped is to review the alarm printout. Note: When it references Channel 1 or 2, it is Actuation Channel 1 or 2, not Logic Channel 1, 2, 3, or 4.

Q847	SFRCS SG 1 Isol
Q848	SFRCS SG 2 Isol
Q963	SFRCS Full Trip
Q692	SFRCS Mn Stm Low Press Trip, Ch 2
Q693	SFRCS Mn Stm Low Press Trip, Ch 1
L886	SFRCS SG Lvl Half/Full Trip, Ch 1
L896	SFRCS SG Lvl Half/Full Trip, Ch 2
P671	SFRCS DP Half/Full Trip, Ch 1
P680	SFRCS Mn Stm Line Low Press, Ch 2
P681	SFRCS Mn Stm Line Low Press, Ch 1

Q847	SFRCS SG 1 Isol
Q848	SFRCS SG 2 Isol
Q963	SFRCS Full Trip
Q692	SFRCS Mn Stm Low Press Trip, Ch 2
Q693	SFRCS Mn Stm Low Press Trip, Ch 1
L886	SFRCS SG Lvl Half/Full Trip, Ch 1
L896	SFRCS SG Lvl Half/Full Trip, Ch 2
P671	SFRCS DP Half/Full Trip, Ch 1
P680	SFRCS Mn Stm Line Low Press, Ch 2
P681	SFRCS Mn Stm Line Low Press, Ch 1
P684	SFRCS Mn Stm Low Press Blk, Ch 2
P685	SFRCS Mn Stm Line Low Press Blk, Ch 1
P691	SFRCS DP Half/Full Trip, Ch 1
P692	SFRCS DP Half/Full Trip, Ch 2

The SFRCS alarms have several flaws: (1) They only tell the status of actuation channels, not individual logic channels. As happens all too often, a power supply is lost to one logic channel, initiating all the alarms for that actuation channel which prevents proper analysis of the trip. (2) Not enough indication is provided of a full trip. Only Q693 is provided to verify a full trip, and it does not tell which channel.

The stroking of the SFRCS valves should be verified within the proper time interval. The following is a list of the SFRCS valves, the computer points, and the stroke times.

	CPT	RESPONSE TIME
ICS11B	Z961	10 seconds
ICS11A	Z969	10 seconds
MS101-1	Z685	10 seconds
MS100-1	Z688	10 seconds
MS394	Z684	10 seconds
MS375	Z687	10 seconds
SP7A	Z680	[use plots] 12 seconds*
SP7B	Z675	[use plots] 12 seconds*
FW612	Z674	15 seconds*
FW601	Z679	15 seconds*
MS106	Z003	36 seconds
MS107	Z006	40 seconds
MS106A	Z004	38 seconds
MS107A	Z007	34 seconds
MS101	Z683	5 seconds
MS100	Z686	5 seconds
TURBINE TRIP	SEE SOE	
AF3872	Z010	34 seconds
AF3870	Z008	34 seconds
AF3871	Z011	33 seconds

AF3869	Z009	34 seconds
FW779	NONE	N/A
FW780	NONE	N/A
AF599	Z970	10.5 seconds
AF608	Z962	13.5 seconds
SP6B	Z678	[use plots]
SP6A	Z673	[use plots]

Per USAR 7.4.1.3.10-9, auxiliary feedwater pumps will be at full speed within 40 seconds from the time of signal initiation.

*Per USAR 7.4.1.3.10-9

Anticipatory Reactor Trip System (ARTS)

There are presently no ARTS SOE points.

The ARTS computer alarms presently available are:

Q001	ARTS In From MFPT*
Q003	ARTS In From T-G*
Q004	ARTS Test Trip*
Q777	ARTS Trip*
Q778	Rx Pwr > 15% and Rx T-G Trip*
Q779	Rx T-G Trip*

*Note that these come in when any one channel trips on the parameter. Therefore, if a channel was tripped hours before, no new alarm will be received when the second channel trips the plant.

Memos have been written to Engineering requesting separate ARTS channel alarms and SOE points.

POST TRIP REVIEW CHECKLIST

	Item	Comments
____	1.0 SOE, Post Trip Review, alarms reviewed, operators interviewed, post trip meeting	____
____	1.1 Prime printout delogged	____
____	1.2 Plots completed	____
____	1.3 Copies of data distributed	____

2.0 Data Analysis

____ 2.1 SOE describes sequence
- ____ RPS trip sequence delineated
- ____ Q180, Q181, and Q266 came in when second channel tripped
- ____ RPS trip makes sense
- ____ All four RPS channels tripped on low pressure after trip
- ____ Verify turbine trip (X030)
- ____ After 30 seconds, verify auto trans (J428, X025, X026)
- ____ Check pressurizer heater cutoff (L770)
- ____ Check TBV positions (Y060 - Y065)
- ____ Check SFRCS, SFAS, ARTS operation, including valve operation time

____ 2.2 Alarms
- ____ Read over all alarms (approximately 20 minutes prior to and approximately 1 hour after)
- ____ Verify Q185, Q186 for reactor trip
- ____ Verify turbine operation:

GOV VLVS Z498-Z501	CLOSED
STOP VLVS Z506, Z508, Z510, Z512	CLOSED
RHT STOP VLVS Z591, Z576, Z578, Z593	CLOSED
RHT VLV Z580, Z581, Z594, Z596	CLOSED
AIR DUMP RELAY X070	TRIPPED
EHC ELECT Q379	TRBL

____ 2nd Makeup Pump On ________ Time (Q754 or Q759)

F741 RC MU FLOW "HIGH"

____ Check atmospheric vents (Z961, Z969)

____ Check deaerator high level trips (L359, L360)

____ Check condensate pump reduction time (Q168, Q171, Q174)
Time__________

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Page 1 of 3

____ Check alarms for SFRCS and ARTS

2.3 Data Analysis

____ RFR operated properly

____ Tave near 552°F

____ Pressurizer level not lost (not < 8")

____ MSSV reset > 960 psig

____ RCS pressure minimum > 1800 psig

____ Review deaerator level after trip

____ Safety systems operated as designed

____ ICS operated as expected

3.0 Support of Outside Organizations

____ NETWORK entry made

____ TAP Team called in/not called in

____ Entrance meeting data complete (if required)

4.0 Report Preparation

____ Report out for comments

____ Comments incorporated and sent to SRB

____ Final report sent to B&W

TRANSIENT COMMENTS:

____

____

____

____

____

____

____

Enclosure 9
Page 2 of 3

POST TRIP PLOTS

PLOT NO.			
1	F674	MN FW 1 FLOW	0-7000 KPPH
	L883	SG 1 SU LVL	0-250"
	Z673	MN FW 1 CU POSITION	0-100%
	Z675	SU FW 1 CU POSITION	0-100%
	P932	SG 1 STEAM PRESS	600-1100
2	F679	MN FW 2 FLOW	0-7000 KPPH
	L893	SG 2 SU LVL	0-250"
	Z678	MN FW 2 SU POSITION	0-100%
	Z680	MN FW 2 CU POSITION	0-100%
	P936	SG 2 OUT PRESS	600-1100
3	J427	GEN GROSS POWER	0-1000 MWe
	R790	RPS AUCT AVE PWR	0-110%
	R795	RPS CH 1 PWR RANGE	0-110%
	R804	RPS CH 2 PWR RANGE	0-110%
4	T782	RC LOOP 2 HLG WR TEMP	520-620°F
	T753	RC LOOP 1 HLG WR TEMP	520-620°F
	T781	RCP 1-1 DISCH WR TEMP	520-620°F
	T821	RCP 2-1 DISCH WR TEMP	520-620°F
5	F874	AFW FLOW TO SG #1	0-1000 GPM
	S008	AFP #1 SPEED	0-5000 RPM
	F875	AFW FLOW TO SG #2	0-1000 GPM
	S018	AFP #2 SPEED	0-5000 RPM
6	P725	RC LOOP 1 HLG PRESS	1400-2400 PSIG
	L768	PRESS COMP LEVEL	0-300"
	T709	RCS AVE NR TEMP	520-620°F
	MODCOMP		
7	S657	MFP #1 SPEED	0-6000 RPM
	S667	MFP #2 SPEED	0-6000 RPM
	L352	DEAR 1 STR TK LVL	6-16'
	L356	DEAR 2 STR TK LVL	6-16'
	MODCOMP		
8	Q190	GROUP 7 ROD POSITION	0-100%
	R794	NI6 D FLUX	-25 to +25
	R803	NI 5 D FLUX	-25 TO +25
	R813	NI 8 D FLUX	-25 TO +25
	R819	NI 7 D FLUX	-25 TO +25

SNB/003

Enclosure 10
Page 1 of 1

Page	Line	Correction or change and reason therefor
CONTINUED		recorder having many problems following my pace.
57	2,3	"we got the startup pump on, we have got the" should be
		we have got the startup pump on ~~xx~~ and we have
		one of the aux feedpups on
57	8	"I said, well, did they"... should be "I said
		how did they .. "
57	21	This is terrible transcription! Change situation
		to EAL. to make this read in a halfway legible
		manner. I cant make out what is being said, but
		this reads correctly.
61	3	"we should cover our butt by ..." should be
		"we should cover ourselves by .." is more appropriate
		language use is not appropriate.
63	16	"they were in ..' to "They were in the procedures"
		to make it read correctly
		TIME RAN OUT

Page No. 9 DATE 8/25/85 SIGNATURE [signature]

Page	Line	Correction or change and reason therefor
95	19	"found out where" should be "found out when"
		to make the sentence read right
54	5	"I was the technical --" ~~I was~~ should be "I
		was the technical engineer" otherwise it makes no
		sense.
54	8	"and then the last it hasn't" to "and then the last,
		it hasn't" punctuation
54	9	"yet I" should be "yet, I" punctuation
55	17	"lake pressure -- temperatures" should be "
		"lake pressure and temperatures" recorder error
		All thru this testimony I was talking rapidly and
		the recorder was having difficulty. There were
		Several interruptions to slow down or clarify comments
55	21	"scared shitless" is better left as "scared to
		death" Comment was inappropriate and should be
		changed as the latter is a more proper description.
55	21	"said, I'm on the" should be "said, I was on the"
		incorrect as transcribed, corrected to make sense.
55	6	"And he didnt say" should be "And he didnt need to
		say" to make it read right.
55	7,8	CONFUSING "but I have given them ~~[illegible]~~" should
		be "but I have given them one minute."
55	9	"And but I" should be "And I" recorder error
55	18	"I got addressed" should be "I got dressed" recorder error

Page No. 3 DATE 6/25/85 SIGNATURE [illegible]

Page	Line	Correction or change and reason therefor
42	All	the recorder was having problems with my talking rapidly
42	12	"when we had tested" should be "when we tested ...
		the system" talking too fast
42	15	"That we" should be "which we" grammar
42	22	"water" should be "pass water slugs" otherwise
		sentence does not read correctly.
43	2	"run of pipe," should be "run of pipe, a"
		to make it read right.
42	6	"that" should be "the", a common problem throughout.
		the transcript.
42	12	"valve itself, that we" should be "valve itself. Two
		punctuation.
.42	14	"Section XI 4.0.5 on" should be "Section XI (4.0.5
		of the technical specifications)". terminology unfamiliar
		with recorder
42	16	"valve, its wired up" should be "valve, that its
		wired up" grammar.
42	22	"steamlines detecting" to "steamlines to detect"
45	9	"is saying is when" should be "is ~~saying~~ talking about
		is when" to make sentence read right
45	15	"on those valves" to "on these pipes" to
		make the sentence make sense
45	18	"piping, and we" to "piping. And we"
		punctuation.

Page No. 2 DATE 6/26/85 SIGNATURE [signature]

Page	Line	Correction or change and reason therefor
34	3	"They have 900 hundred RPM" should be "They have to take
		action prior to 900 RPM". otherwise sentence makes no sense
34	8	"for the exciter The generator is" should be "for the
		exciter no. for the generator yes" I was talking fast
		and there was difficulty with the recording process. The
		recorder kept interrupting to slow me down.
34	10	"to open exciter" should be "to open the exciter breaker"
		to make sentence technically correct.
38	21	"aux feedwater" should be "aux feedwater comment".
		to make the sentence understandable
38	23,24	"and the main steam or the" should be "and the"
		recorder not following terminology
39	1	"and set valves" should be "and intercept
		valves" recorder not familiar with terminology
39	2	"they are" should be. "they shut" otherwise
		makes no sense.
39	6	"that was running that" should be "that was running
		the" grammar change
39	22	"With no" should be "By having no" to read right
37	23	"extractions" should be "extractions" grammar problem
42	4	"the cold piping, hot steam" should be "the cold
		piping with hot steam" recorder error
42	11	"uses saturated steam" should be "supplies saturated steam"
		terminology problem, corrected to make it read right

Page No. 1 DATE 6/25/85 SIGNATURE [signature]

Page	Line	Correction or change and reason therefor
6	12	station air - NOT stationary - Transcript error Reason
12	14	machine - NOT measure - Transcrip error
18	5	manned - NOT man I wanted to & thought I said manned.
28	2	plant - NOT point - Transcrip error
30	1	opening and - NOT range - What I thought I said
32	1	cold - NOT code - Transcrip error
33	16	altrex - NOT all directs - altrex is AC filter name.
40	17	lit - NOT lid - Transcrip error
40	22	lit - NOT lid - Transcrip error
45	5	pots - NOT spots - Transcrip error -

Page No. 1 DATE 6-21-85 SIGNATURE Louis Simon