Washington Public Power Supply System
A JOINT OPERATING AGENCY

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Docket No. 50-397

July 11, 1980
G02-80-149

Director, Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington D.C. 20555

Attention: Mr. B. J. Youngblood, Chief
Licensing Branch No. 1
Division of Licensing

Subject: WPPSS NUCLEAR PROJECT NO. 2
RESPONSES TO ROUND ONE QUESTIONS
SET NINE, REACTOR SYSTEMS BRANCH (RSB)

Dear Mr. Youngblood:

Enclosed please find sixty (60) copies of the responses to Round One, Set Nine questions from the Reactor Systems Branch (RSB). These questions are to be incorporated formally into the FSAR in the next amendment.

Very truly yours,

for D. L. RENBERGER
Assistant Director - Technology

DLR:CDT:ct
Enclosure
cc: JJ Verderber, B&R, w/o attachment
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WPPSS NUCLEAR PROJECT NO. 2
RESPONSES TO ROUND ONE QUESTIONS
SET NINE, REACTOR SYSTEMS BRANCH (RSB)

Wm. W. Waddel, Being first duly sworn, deposes and says: That he is the Acting Assistant Director, Technology, for the WASHINGTON PUBLIC POWER SUPPLY SYSTEM, the applicant herein; that he is authorized to submit the foregoing on behalf of said applicant; that he has read the foregoing and knows the contents thereof; and believes the same to be true to the best of his knowledge.

DATED July 10, 1980

WM. W. WADDEL

On this day personally appeared before me, Wm. W. Waddel, to me known to be the individual who executed the foregoing instrument and acknowledged that he signed the same as his free act and deed for the uses and purposes therein mentioned.

GIVEN under my hand and seal this 10th day of July, 1980

Reba B. Helgeson
Notary Public in and for the State of Washington
Residing at Richland

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SUBJECT: Responds to Round One Questions,Set 9,Questions 211.049 - 311.106.

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RESPONSES TO

REACTOR SYSTEMS BRANCH (RSB)

QUESTIONS 211.049 - 211.106

Q. 211.049

The analyses you present in the FSAR to show compliance with the requirements for protection against overpressurization which are contained in the ASME Boiler and Pressure Vessel Code, refers to the General Electric topical report, NEDO-10802, for the analytical model used to evaluate transients in the WNP-2 facility. However, GE has submitted an updated analytical model, ODYN, to evaluate plant transients. Accordingly, reanalyze the pressure transients in the WNP-2 facility using the ODYN code. Alternatively, provide assurance that the method of analysis described in NEDO-10802 is bounding in regard to predictions of the peak pressure. The analysis must include the effects of the recirculation pump trip (RPT) due to high pressure and the RPT trip resulting from the turbine stop valve/control valve closure, where applicable. If you reanalyze the pressure transients using the ODYN code, provide an analysis which establishes whether the closure of all main steam isolation valves (MSIV's) is the most severe overpressure transient, including consideration of a second safety-grade scram (e.g., a scram resulting from a high neutron flux) and the effects of the RPT.

Response:

WPPSS commits to reperformance of the overpressure protection analysis, to demonstrate compliance with the ASME B&PV Code considering the effects of end-of-cycle and ATWS RPT. For the limiting rapid pressurization transients, the ODYN code will be used to reperform the calculations using the resolution basis of Option B of the NRC letter on the subject code dated January 23, 1980 (GE/NRC generic resolution in progress estimated to be completed, summer 1980). Appropriate analyses will also be done with ODYN to bound Ch. 15 limiting pressurization transients. The FSAR will be updated when the analysis are completed to reflect the results of these analyses both in Ch. 5 and Ch. 15.

Q. 211.050

You have not provided sensitivity studies in the FSAR which show the effect of the initial operating pressure on the peak transient pressure attained during a limiting over-pressure event. Accordingly, submit the following additional information.

a. Provide a sensitivity study which shows that increasing the initial operating pressure, up to the maximum pressure permitted by the high pressure trip setpoint will have a negligible effect on the peak transient pressure.

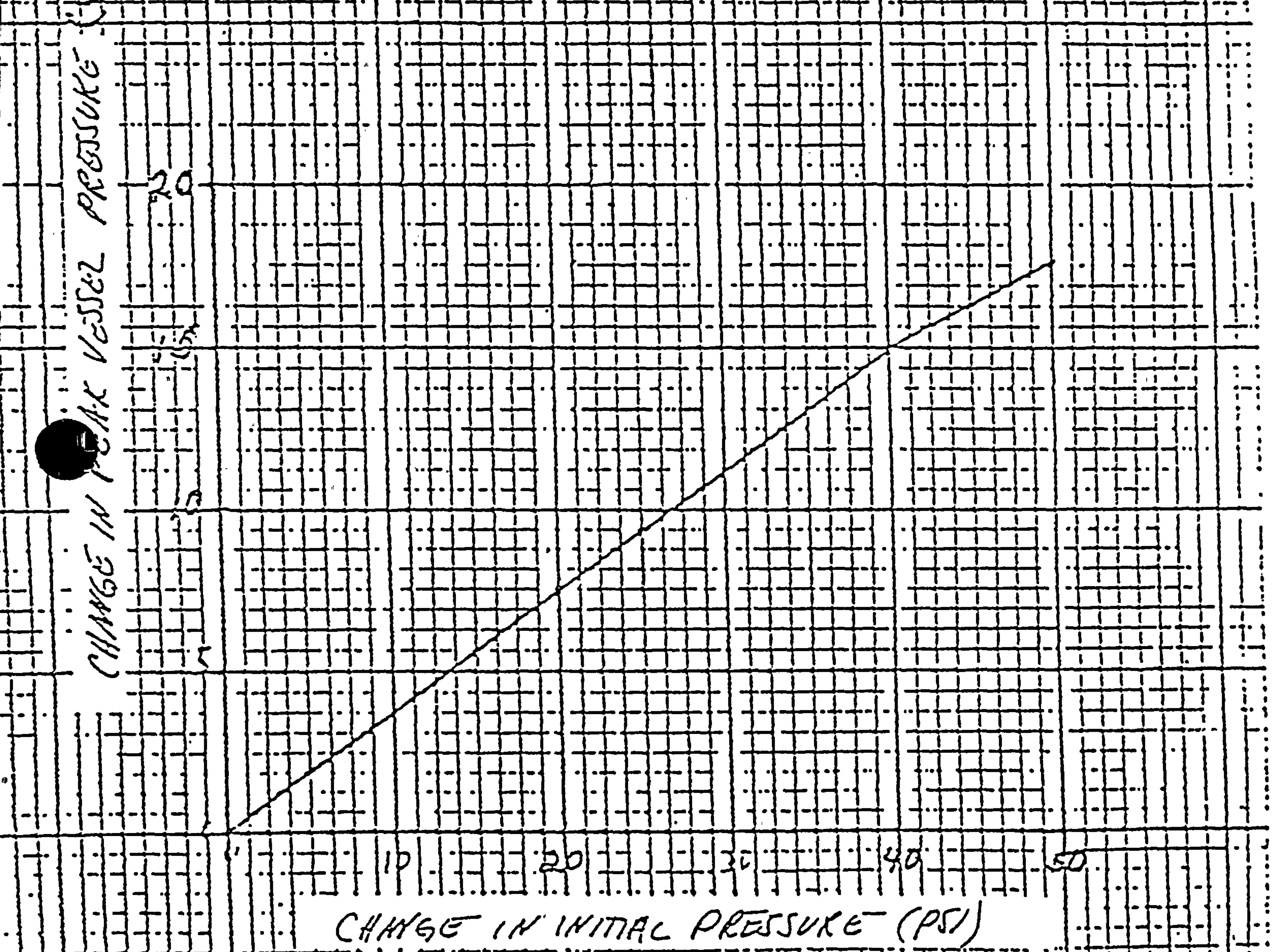
b. Alternatively, propose an operating limitation on the reactor pressure which will be incorporated into the WNP-2 Technical Specifications, thereby providing assurance that the actual reactor operating pressure will not exceed the initial pressure assumed in your analysis of pressure transients.

Response:

The overpressure analysis shown in Chapter 5 of the FSAR dome assumed the plant is initially operating at 105% steam flow condition with a maximum vessel dome pressure of 1020 psig. The maximum operating dome pressure at 100% power is expected to be 1005 psig, therefore, the assumed initial operating pressure of 1020 psig is expected to be conservative relative to expected actual operation. In addition, the nominal high pressure scram setpoint is expected to be set at 1043 psig. A study has been performed for a BWR-3 to investigate the effects of increasing the initial reactor pressure relative to the initial value used in the overpressure protection analysis on the peak system pressure. The conclusion was that increasing the initial operating pressure results in an increase of the peak system pressure, which is less than half the initial pressure increase as shown in Figure 211.050-1 for the overpressure design transient (i.e., all MSIV closure with indirect high neutron flux scram). The same general trend is expected to exist for WNP-2. For the WNP-2 project, the allowable value for the proposed technical specification limit on the high reactor pressure scram is 1063 psig. Therefore, the maximum increase in the initial pressure would be limited to only 43 psi and the maximum peak system pressure increase during the overpressure design transient would be limited to less than 20 psi. Thus the overpressure criteria would still be satisfied.

FIGURE B 211.50-1

TYPICAL BWR CHARACTERISTIC
MSIV CLOSURE FLUX SCRAM



Q. 211.051
(5.2.2)

The performance of essentially all types of safety/relief valves has been below the expectations for this type of safety-related component. Based on the number of reportable events involving malfunctions of these valves in operating boiling water reactors (BWRs), we believe that significantly improved performance of the safety/relief valves (SRVs) should be required of the SRVs installed in new plants such as the WNP-2 facility. Accordingly, provide a detailed description of the provisions you will incorporate in the SRVs of the WNP-2 facility which represent an improvement over the SRVs of presently operating BWR plants in the six areas listed below. In responding to this item, explain why or how your additional provisions will provide the improvements which we seek in the performance of the SRVs. Finally, identify the SRV manufacturer.

a. Valve and Valve Operator Type and/or Design. Provide a discussion of your proposed improvements in the air actuator, especially in the materials used for such components as the diaphragms and the seals. Discuss the safety margins and confidence levels associated with the air accumulator design. Discuss the capability of the reactor operator to detect low pressure in both air accumulators.

b. Specifications. Indicate what new provisions you have employed to ensure that the specifications for the valves and valve actuators include design requirements which reflect the operation of the SRVs over the anticipated range of environmental conditions (i.e., the temperature, humidity, and vibration), to which the valves and valve actuators will be subjected during plant transients and postulated accidents.

c. Testing. It is our position that prior to installation, the SRVs should be proof-tested under the appropriate environmental conditions, for time periods representative of the most severe operating conditions, to which they may be subjected.

d. Quality Assurance. Indicate what new programs you have instituted to assure that valves are manufactured to your design specifications and will operate as required by your specifications. For example, indicate the test you will perform to assure that the blowdown capacity of the SRVs is correct.

e. Valve Operability. Provide a description of your surveillance program to monitor the performance of the SRVs during the plant lifetime. Identify the information that will be obtained in this surveillance program and indicate how these data will be utilized to improve the operability of the valves. For example indicate how this program will reduce the malfunctions that have occurred in operating BWR facilities.

f. Valve Inspection and Overhaul. You state in the FSAR that half of the SRVs will be bench-checked and visually inspected every refueling outage. However, depending on operating cycle length, this may result in several years between inspections. Our concern in this matter arises from operating experience which has shown that failure of the SRVs may be caused by exceeding the manufacturer's recommended service life for the internal components of the SRVs or their air actuators. Accordingly, indicate the frequency at which you intend to visually inspect and overhaul those SRVs which function as part of the automatic depressurization system (ADS). Indicate what provisions will be incorporated into the WNP-2 facility to ensure that inspection and overhaul of all the SRVs is in accordance with the manufacturer's recommendations for the SRVs installed in the WNP-2 facility and that the design service life for any component of the SRV, is not exceeded.

Response:

A. Valve and Valve Operator Type and/or Design

Past BWRs utilized reversed-seated, pilot-operated, safety/relief-type valves as shown in Figures 211.051-1 and 211.051-2. WNP-2, which is a GE BWR/5, utilizes a conventional-type simple, direct-acting, spring-loaded, safety/relief valve with an auxiliary pneumatic actuator assembly with solenoid valves to provide for an independent mode of operation for relief service based upon user/operator command. (See Figures 211.051-3 and 211.051-4.) As such, the safety/relief

function is directly and automatically controlled by the static steam pressure acting at the main seat of the valve inlet nozzle and disc.

The independent mode of operation is via the servo-air-pneumatic cylinder-valve arrangement and mechanism when actuated by the user/operator. Use of the conventional simple, direct-acting, spring-loaded, safety/relief valve provides the optimum accepted type of overpressure protection device presently available with numerous years of relief experience in similar industrial, marine, and naval steam service applications. See Table 211.051-1 for SRV improvements as compared to present operating plants.

Material selections for this type of safety/relief valve (Crosby dual function) are in accordance with ASME Section III and are suitable for the intended environment and functional application. Successful qualification test results confirmed the adequacy of material selections. Each safety/relief valve and actuator assembly is subjected to relief operations to verify proper operability and leaktightness prior to delivery.

Note that should the air supply fail, the pneumatic actuator assembly may not be able to open the valve in the relief mode of operation. The independent safety mode for overpressure protection is not affected by a loss in air supply.

With regard to the air accumulators, each safety/relief valve has a relief accumulator sized to allow one actuation against normal drywell pressure with reactor pressure at 1000 psig, should the air supply to the valve fail. The ADS valves each have a separate accumulator sized to allow one actuation against maximum drywell pressure with the reactor at 0 psig, should the ADS air supply fail. Failure of the air supply is extremely unlikely since the ADS air supply is Seismic Category I back through the nitrogen bottles.* See the response to Question 211.048.

Insert paragraph next page

A summary of operating experience of the Crosby direct acting valve to date is contained in the response to Question 212.131 on the LaSalle docket. The design of the SRVs to be installed in WNP-2 are a modified version of those installed in Chinshan 1 and 2. Based on operating experience (principally Browns Ferry), recent modifications to the Crosby valves were incor-

Insert

Each air or nitrogen supply system (2 ADS + 1 normal) has pressure indication and alarm to indicate low pressure conditions in the system. Excessive compressor cycling would indicate leakage if pressure does not drop low enough to actuate the alarm. Specific indication of individual accumulator pressure is not required since the only occurrence not indicated by the above would be isolation of an accumulator system with the manual isolation valve. This is extremely unlikely since each accumulator/check valve is inspected and tested per IWV (Section XI). A pressure decay test is performed as a final part of the maintenance procedure to prove system operability. (See part C of this response.) This test requires the manual isolation valve be open. In addition, of course, the safety/ relief valve for protection against overpressure is automatically controlled and actuated by static inlet steam pressure and is not dependent on an air supply.

porated to reduce the potential for steam leakage, thereby minimizing maintenance and improving plant availability. The changes include the following:

1. Modifications to the lifting mechanism, adjusting bolt and thrust bearing adapter to improve the opening and closing kinematics, reduce friction and improve alignment of the valve during operation;

2. Replacement of the nozzle and disc from Crosby's standard design configuration to a semi-flexible disc of Inconel and a 316 stainless steel flexi-disc nozzle for improved seat tightness;

3. Raising of the setpoint or the lowest set SRV to be 150 psi above the nominal reactor operating pressure to reduce relief valve simmering.

Insert paragraph next page

B. Specifications

The GE Safety Relief Valve Equipment Specification(s) identifies and includes all the design requirements necessary for operation of the valve and valve actuator assembly in its expected normal and postulated abnormal environments. Verification of the design for safety/relief valve acceptability is and has been demonstrated by life cycle testing, environmental testing in accordance with IEEE 323-1971, and seismic testing in accordance with IEEE 344-1975.

C. Testing

The design of the safety/relief valve has successfully demonstrated compliance with performance requirements when subjected to the following qualification test programs:

1. Life Cycle Test(s)

This test program consists of subjecting production-tested safety/relief valve assembly of the design to be used to 300 relief (power) and safety (pressure) actuations in order to demonstrate acceptability of the valve design to meet: (1) set pressure, (2) opening and closing response times, (3) blowdown, (4) seat tightness; (5) flow-rated capacity lift (ASME) during each actuation; (6) reclosure (after each actuation) without demonstrating a tendency

Insert

Prequalification production tests were made on each modified SRV at the vendor's plant. Data on those tests is filed at GE (San Jose) in "Design Reference File 207C-B21/22 F013-D (6xRx10) - Crosby SRV Modification Effort". These design improvements significantly reduced the inherent SRV potential leakage to below specification leakage (20 lb/hr); these design improvements did not adversely affect other required functions.

to stick open, chatter or disc oscillation, and emergency operability requirements. Conditions such as environmental temperature, pressure ramp rates, pneumatic operating pressure, solenoid voltage and backpressure were varied, consistent with test facility capabilities, to assure valve operability under the limits of the normal expected conditions to which the safety/relief valve may be subjected. This test program establishes the qualified service life of the safety/relief valve. A summary of the results of this test program is as follows.

Following the prequalification production tests, each modified SRV was then subjected to life cycle qualification tests as outlined in Wyle Lab Test Procedure 444414-01 in accordance with the GE Specification 22A6595. This included approximately 300 relief (power) and safety (pressure) actuations to demonstrate and characterize each valve for acceptable BWR service. Test parameters included:

a. seat tightness/leakage characteristics,
b. set pressure,
c. opening and closing response time,
d. blowdown,
e. SRV lift-achieving rated flow capacity lift during each activation,
f. SRV reclosure without chattering, disc oscillation, or stick open, and
g. capability to open without inlet steam when activated on demand.

Test conditions were varied according to facility capability to assure valve operability across the design limits to which the SRV may be subjected while in service. These included: temperature, pressure ramp rates, pneumatic operating pressure, solenoid voltage, inlet pressure, and the dynamically imposed backpressure.

Test results indicate essentially zero leakage for both the relief (power) and safety (pressure) modes of SRV operation, all valves and seat-tightness capability to meet the 20 lb/hr specification limit and saturated steam conditions. Each valve demonstrated safety actuation at the nameplate value plus 1% at a confidence level of 0.95. The response is also linear with ambient

temperature in the negative direction, i.e., at temperatures above 135°F the actual pop pressure is lower than the nameplate value. The temperature correction value is 0.2 psi per °F for this SRV. Set pressure is independent of ramp rate variance. Response of the SRV is directly related to the effective differential pressure force acting to open the SRV, therefore, outlet static pressure at the exit can be accurately accounted for.

Opening times were as follows for the test set up:

safety actuation time - $0.020 \leq t \leq 0.30$ seconds

relief actuation time - $0.020 \leq t \leq 0.15$ seconds

Actual installation times could result in a delay time of 0.10 seconds added for wire lengths and other non-SRV wire losses. Closing times were:

safety actuation - none, blowdown requirement controls this

relief actuation - time to de-energize solenoid $\leq$ 0.90 seconds disc travel after solenoid was de-energized $\leq$ 1.50 seconds

Blowdown within the required range of 2 to 11% was demonstrated. Each SRV is adjusted according to its spring rate for acceptable blowdown.

Qualification test results demonstrate that the modified SRV will open to rated capacity lift in either the relief or safety modes of operation when actuated.

SRV reclosure was demonstrated throughout the qualification tests without sticking, chatter, or disc oscillation during the closure stroke. When inlet pressure was increased to repressurize to the set pressure, the SRV reactuated to the full open position. The modified SRV will open to its full rated capacity lift position when operated in the relief mode with the inlet pressure at zero psig, thus demonstrating its emergency operability.

Six SRVs were included in this life cycle qualification test program. Test anomalies corrected during this demonstration do not invalidate the adequacy of the test results obtained; the finalized modified SRV design is considered acceptable for BWR main steam applications.

2. Environmental Test(s)

This test program consists of subjecting a production-tested pneumatic actuator assembly (includes air cylinder with electrically operated solenoid valve assemblies) unit of the design to be used on the safety/relief valve to the environmental influences of radiation, thermal aging, mechanical aging, negative pressure and the postulated LOCA steam environment in order to demonstrate acceptability of the actuator design to meet operability requirements. The test program is in accordance with IEEE 323-1971 requirements and establishes the qualified service life of the actuator assembly. A summary of the results of the test program is as follows.

The solenoid valves of the pneumatic actuator were subjected to a test sequence as follows:

a. radiation aging to 30 x 10^6 rads,

b. mechanical aging to 200 cycles, and

c. exposure to emergency environmental conditions of 340°F at 65 psig decreasing to 250°F at 25 psig.

Valve operability was demonstrated during and after exposure to the emergency environment.

3. Seismic Test(s)

This test program consists of subjecting a safety/relief assembly of the design to be used to seismic tests in accordance with IEEE 344-1975 to demonstrate acceptable functionality and structural integrity of the design when static moments are applied to the inlet and outlet flanges and dynamic and seismic OBE and SSE loads are imposed separately and combined. A summary of the results of the test program is as follows.

One valve specimen was subjected to OBE and SSE accelerations and flanged end connection moment loading with valve inlet pressurized with saturated steam. Valve operability was demonstrated during and after application of loading. Maximum test loads were 8 x 10^5 inch pound moment at valve inlet and 6 x 10^5 inch pound moment at valve outlet. Maximum seismic accelerations were 5.0g horizontal and 4.2 vertical.

D. Quality Assurance

The GE safety/relief valve specification incorporates all of the required performance, structural, interface and test requirements.

To assure that safety/relief valves are manufactured and will perform to the requirements specified by the GE safety/relief valve specification, the following types of actions are taken with the valve supplier:

1. Valve supplier is evaluated for capability in complying with specification requirements.

2. A qualified design is established that demonstrates compliance with specification requirements.

3. The details and manufacturing process of the qualified design is frozen.

4. Each safety/relief valve assembly is manufactured to the approved design freeze list and manufacturing procedures.

5. Each safety/relief valve and actuator assembly is production tested to GE approved procedures to assure a high degree of confidence that the delivered equipment will perform as required.

6. Quality Assurance inspection points are instituted throughout the process along with both general and random GE surveillance and periodic audits.

For example, to verify that the SRV flow capacity is correct, the following is verified or performed:

1. Design is ASME certified for flow capacity.

2. Nozzle bore diameter is dimensionally inspected.

3. Each valve is checked to assure that it opens to flow capacity lift position by use of an LVDT and O-Graph readout.

E. Valve Operability

1. Each SRV is equipped with a position indicating device showing actual valve position instead of the ordered position. The indicators permit prompt operator response to a malfunction or emergency situation and contribute to identification of corrective maintenance requirements. (Note: This indication system is currently under design and is not yet refected in the FSAR.)

2. Routine surveillance of SRV discharge-port thermocouple recorder readings are conducted to identify valves which have operated or show a tendency to leak. This data will be used in identifying preventative or corrective maintenance requirements.

3. SRV accumulator check valves are functionally tested for seating capability by performing an accumulator pressure decay test on a frequency as specified by IWV, ASME Section XI. In conjunction with the pressure decay test, accumulators are blown from low-point drains and evidence of excessive moisture or particulate matter is used in adjusting refurbishing schedules of SRV piston-cylinder actuator assemblies and pilot solenoids.

4. Solenoid circuit integrity for valves performing an ADS function is monitored during normal control room operations. Energized indicating lights at control room panels H13-P628 and H13-P631 verify solenoid circuit continuity.

5. For valves performing an ADS function, channel functional testing will be performed monthly in accordance with the WNP-2 Technical Specifications. Testing will verify operability of sensors and associated circuitry.

6. SRV history logs are maintained which contain the following type of information in a readily retrievable form:

a. Valve identification by SRV supplier, type, style or model number and serial number.

b. Date placed into service.

c. Date removed from service along with the estimated number of cyclic operations and hours that the SRV has been in actual service.

d. Identification of all tests, results noted, disassemblies performed (including extent and purpose), maintenance, refurbishments, modifications and replacement parts made to the SRV along with reference to the applicable procedure or instructions used. The historical information provides insight into the potential problem area(s) that can be corrected.

F. Valve Inspection and Overhaul

1. SRV/ADS pilot solenoids and air-cylinder actuators will be inspected and refurbished on a three-year cycle in accordance with the manufacturers recommendation; unless surveillance activities indicate a more frequent refurbishment as evidenced by excessive moisture or particulate matter in the air supply.

2. Adherence to the manufacturer's recommended schedule of inspection and overhaul is aided with the use of the SRV history log. Routine surveillance of the SRV history log and instruction manual insures that the design service lift for any components of the SRVs or their air actuators is not exceeded. SRVs will be refurbished in accordance with the manufacturer's recommendation on a frequency defined by IWV, ASME Section XI.

Please note that in addition to the above response, the BWR Owner's Group for Three Mile Island Concerns is working with GE to develop a more comprehensive response to these concerns. We are actively participating in this program and will implement applicable recommendations developed as a result of the meetings and discussions between the Owners Group and the NRC.

*Draft FSAR page changes attached.

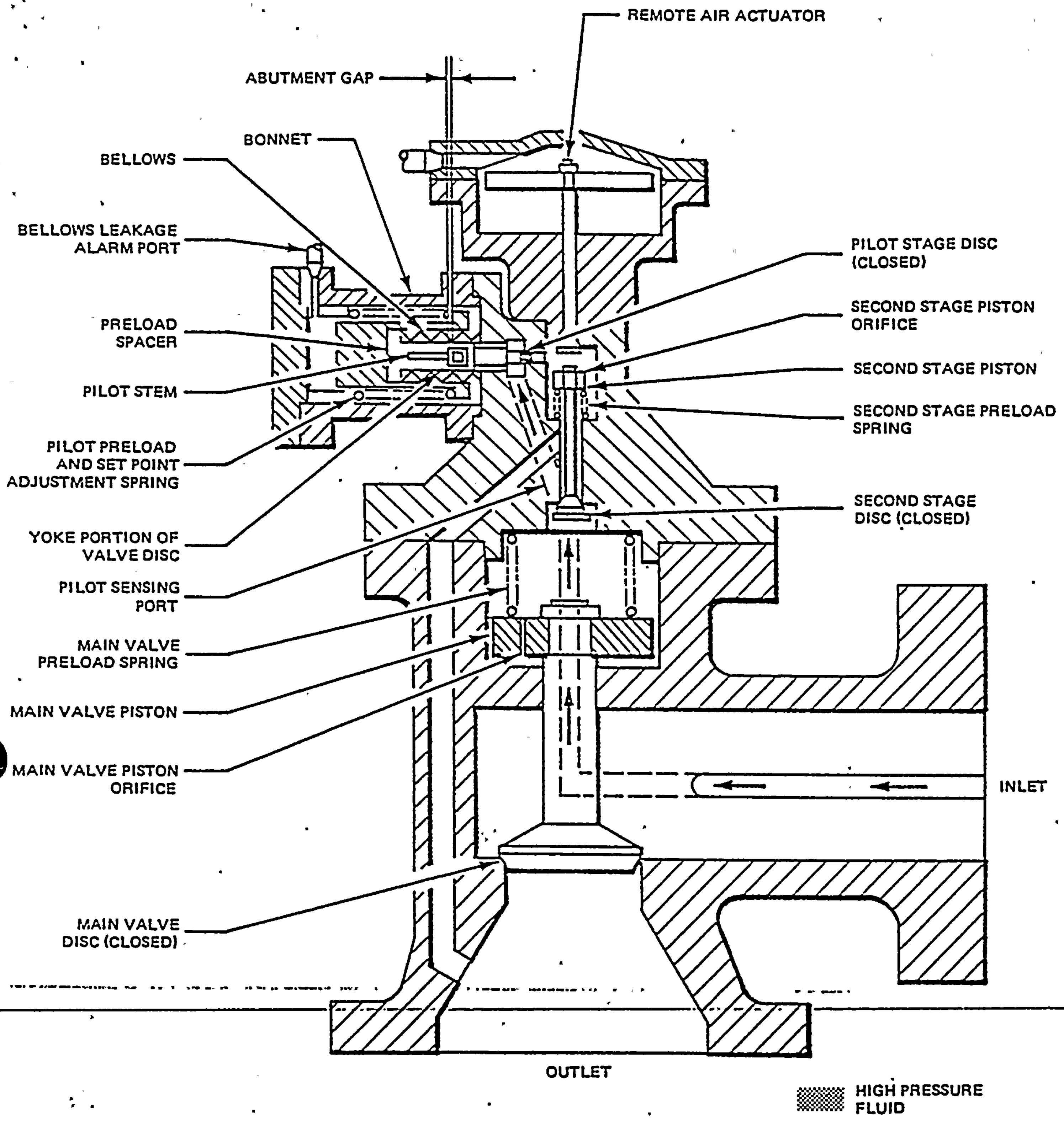
211.51-1

TABLE ~~1~~

COMPARISON OF SRV IMPROVEMENTS

DESCRIPTION	OTHER PLANT(S)	WNP-2	REMARKS
Valve Manufacturer	Target Rock Corporation	Crosby Valve & Gage Co.	
Valve Type	Reverse Seated, Pilot Operated, Dual Function	Direct Acting, Spring Loaded, Dual Function	See Figures ~~1 and 2~~ 211.51-1 THROUGH 211.51 For Cross-Section View(s)
Valve Model/Style	67F	HB-65-BP	
Valve Size	6 inch inlet 10 inch outlet	6 inch inlet 10 inch outlet	
Performance Anomalies	Excessive pilot leakage resulting in plant blow-down.	No pilot used.	Steam leakage past the Crosby type SRV nozzle and disc interface does not result in inadvertent SRV opening to cause a plant blowdown. SRV opening will resul due to a system pressure exceeding SRV spring set or if the actuator cylinder i actuated.
	Air operator diaphragm failure due to use of an inadequate diaphragm design and incorrect lubrication.	No diaphragms used.	The Crosby type of SRV utilizes a standard type (direct acting) pneumatic cylinder which contains proven static and dynamic seals which have been properly lubricated. The design and materials used has been successfully subjected to life cycle and environmental tests.

2 211.51-12



~~Rev. 12, 9/79~~

~~SUSQUEHANNA STEAM ELECTRIC STATION~~
~~UNITS 1 AND 2~~
~~FINAL SAFETY ANALYSIS REPORT~~

~~VALVE SCHEMATIC (CLOSED)~~

~~FIGURE 211.70-1~~

TARGET ROCK VALVE SCHEMATIC (CLOSED)

FIGURE 211.51-1

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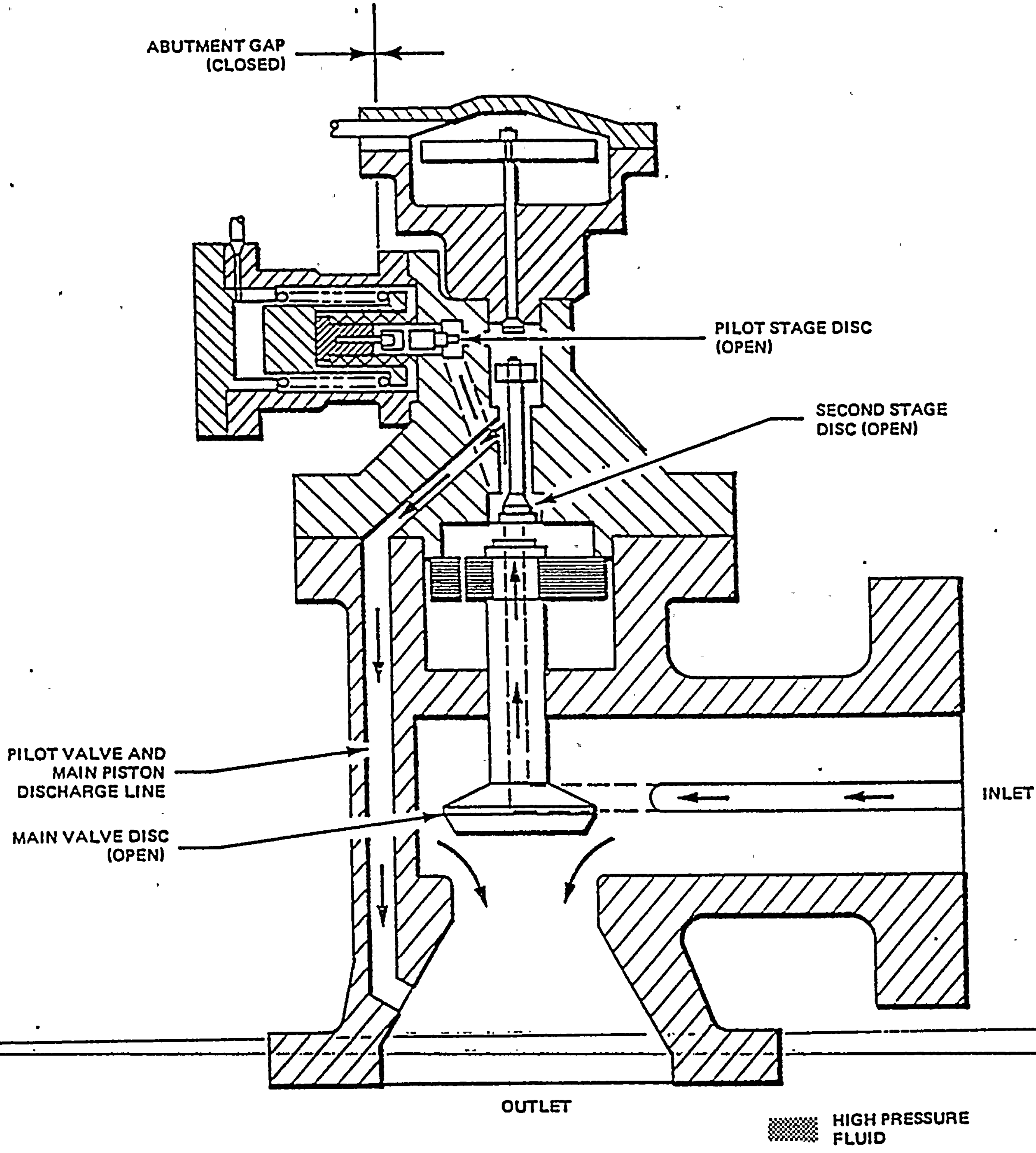

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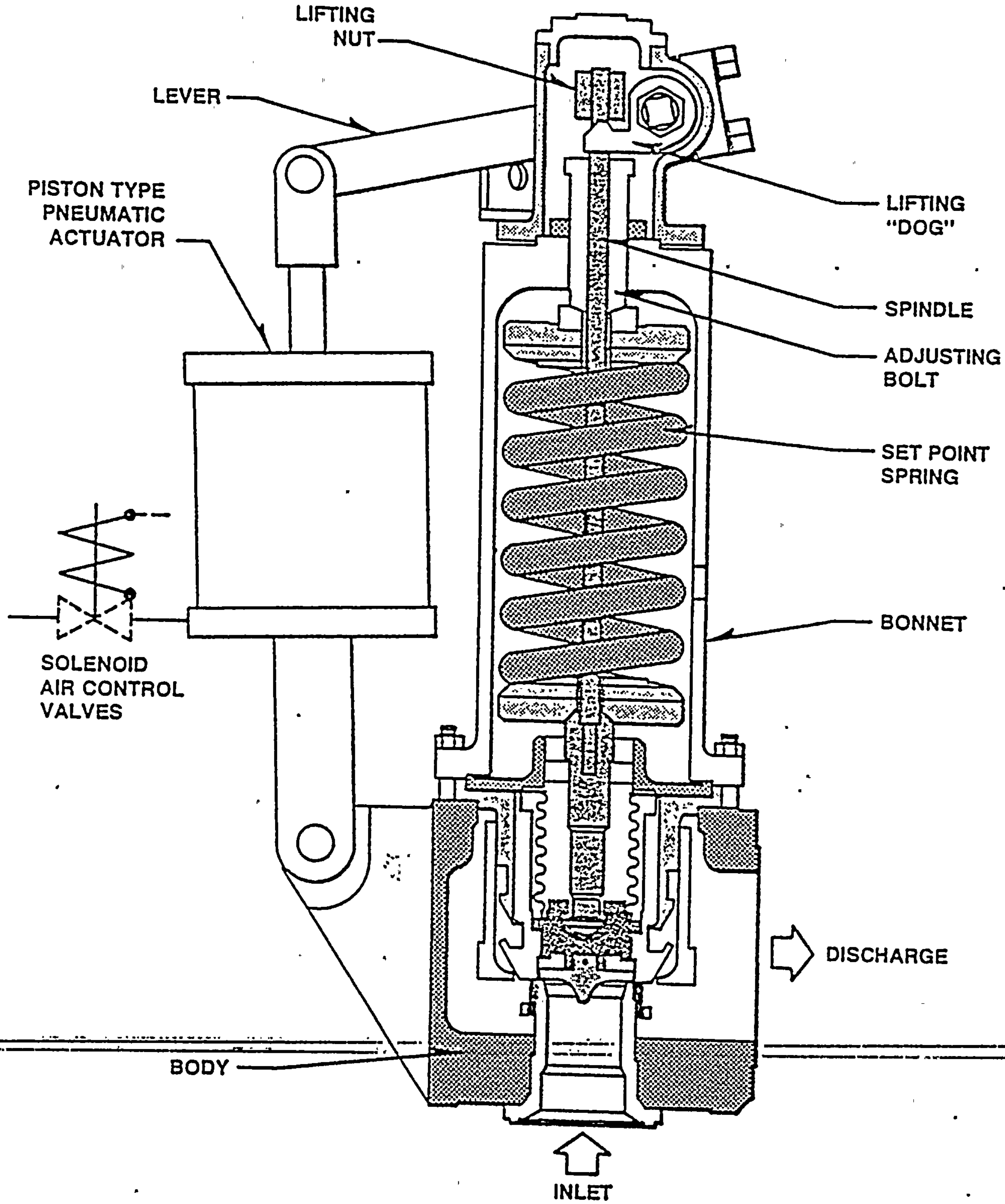
~~FINAL SAFETY ANALYSIS REPORT~~

~~VALVE SCHEMATIC (OPEN)~~

~~FIGURE 211.70-1a~~

TARGET ROCK VALVE SCHEMATIC (OPEN)

FIGURE 211.51-2



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~~UNITS 1 AND 2~~
~~FINAL SAFETY ANALYSIS REPORT~~

~~CROSBY VALVE~~

~~FIGURE 211.70-2~~

CROSBY VALVE

FIGURE 211.51-3

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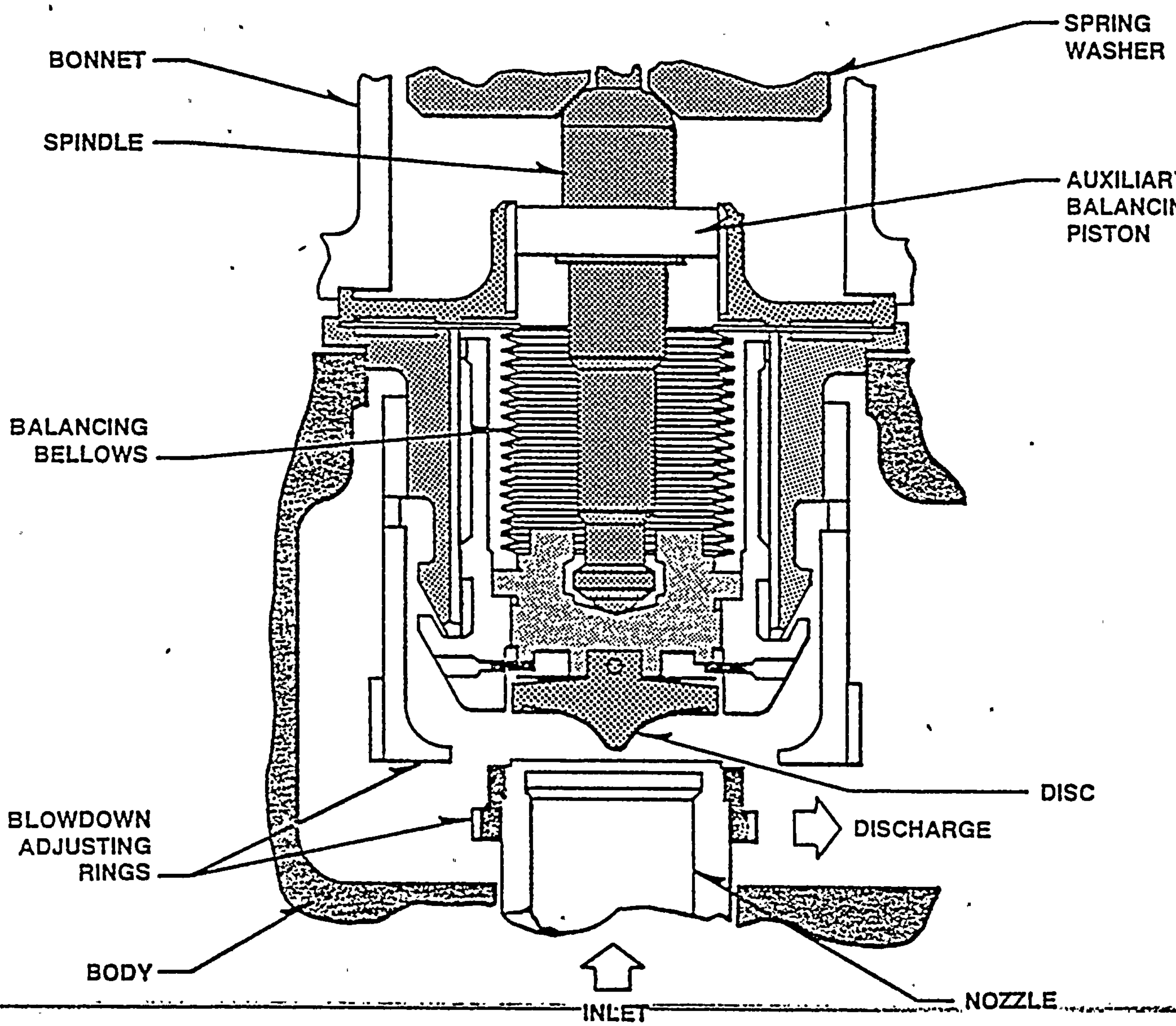

Rev. ~~12, 9/79~~

~~SUSQUEHANNA STEAM ELECTRIC STATION~~
~~UNITS 1 AND 2~~
~~FINAL SAFETY ANALYSIS REPORT~~

~~INTERNAL DETAILS OF CROSBY VALVE~~

~~FIGURE 211.70-2a~~

INTERNAL DETAILS OF CROSBY VALVE

FIGURE 211.51-4

The air compressors, dryer filters, and supply piping for the containment instrument air system provide air for charging the accumulators of the main steam isolation valves (inside primary containment) and the main steam safety/relief valves during normal operation (see 5.2 and 5.4). Since operation of this portion of the equipment in the containment instrument air system is not required for safe shutdown of the reactor (see 7.3 and 7.4 for effects of loss of instrument air on the main steam isolation and safety/relief valves), the pressure containing components are designed and constructed in accordance with ASME Section VIII, and system piping is designed and fabricated in accordance with ANSI B31.1, Seismic Category II. (System piping supports are Seismic Category I.) The only exception is that portion of the piping system from the outermost containment isolation valve to the solenoid valves of the main steam safety/relief and isolation valves (inside primary containment) which are ASME Section III Class 2, Safety Class 2 and Seismic Category I.

Two banks of nitrogen gas bottles and supply piping are provided as part of the containment instrument air system to supply the Automatic Depressurization System (ADS) main steam safety/relief valves with a pneumatic supply. For a discussion of the function and operation of the ADS, see 6.3 and 7.3. The nitrogen bottles and associated equipment are

standard commercially available un[illegible]

~~classified Safety Class G,~~ and the supply piping is ASME Section III, Class 2 and Class 3. The entire system from the mounting of the bottles through the piping and isolation valves to the relief valves is Seismic Category I.

9.3.1.2 System Description

9.3.1.2.1 Control and Service Air System

The control and service air systems are shown schematically in Figure 9.3-1. Three compressors and three air receivers supply both control and service air requirements.

Each compressor has a start-standby-stop remote selector switch and an unloader control. When the selector switch is set in the start position, the compressor runs continuously and loads and unloads to maintain receiver pressure. When the selector switch is in standby position, the standby compressor will automatically start when receiver pressure falls below 90 psig. Normally two compressors are running and one compressor is placed on standby.

This system consists of two 100% capacity air compressors, associated coolers, a twin tower air dryer, filters, an air receiver, valves, and piping of a leak tight design. In addition, two nitrogen gas bottle banks and associated piping are provided as a backup to the compressor supplied air for seven of the main steam relief valves which perform the ADS function.

The compressors located in the reactor building take suction from the building atmosphere through intake filter-silencers which are 98% efficient in filtration of particles as fine as five microns. The air is then discharged through an aftercooler, a prefilter, a dryer, an afterfilter and air receiver to deliver dry, clean, pressurized air to the pneumatic control systems of the following valves inside the primary containment vessel:

a. Four main steam isolation valves and their accumulators,

b. Eighteen main steam safety/relief valves and their accumulators.

The two independent nitrogen bottle bank subsystems are provided to deliver pressurized nitrogen to seven of the safety/relief valves and accumulators. These seven valves perform the ADS function, if required, during postulated LOCA conditions. These nitrogen banks ensure a 30-day supply of nitrogen for the ADS function during isolation of the compressor loop. One bank of 15 bottles supplies nitrogen for three main steam safety/relief valves and accumulators, while the other bank of 19 bottles supplies four main steam safety/relief valves and accumulators (see Figure 9.3-2). [A]

The nitrogen bottles are located in the railroad lock of the reactor building to facilitate access. The bottles are standard, commercially available units pressurized to 2490 psig. Each bottle has a capacity of 257 SCF. The required quantity [B] of bottles for each bank was conservatively based on providing a 30-day supply to the ADS valves to satisfy the long term post-LOCA demand based on the following:

A [Under normal operating conditions, the ~~pressure~~ controlled leakage boundary of the Reactor Building is maintained above the railroad lock so access is available to the bottles for recharging if required.

B [However, the bottles are mounted in accordance with seismic Category I, Quality Class I requirements. ~~however~~

9.3.1.3.2 Containment Instrument Air System

Since each of the two nitrogen supplies and the compressed air supply are independent of each other, a single component failure in one will not effect the operational function of the other.

During normal operation, one compressor will operate intermittently to restore loss of pressure in the main steam isolation and safety/relief valve accumulators. The compressor loop discharge piping can be isolated, if required, under accident conditions. Each nitrogen bottle supply line isolation valve is powered from a different division of the critical power supply.

In the event of loss of power to the compressed air supply, the individual air accumulators serve as a reliable source of compressed air for the main steam isolation and safety/relief valves. The accumulators in addition are supplied with a safety grade source of nitrogen (two independent banks of nitrogen bottles). Further discussion of the effects of loss of air to the main steam isolation and safety/relief valves is presented in ~~7.3 and 7.4.~~ 7.3.1.1.11, 6.3 and 5.2.2.4

9.3.1.4 Testing and Inspection Requirement

The systems are inspected and cleaned prior to service. Instruments are calibrated during testing, and automatic controls are tested for actuation at the proper set points. Alarm functions are checked for operability and limits during plant operational testing. The systems are operated and tested initially with regard to flow paths, flow capacity, and mechanical operability in accordance with Chapter 14.

The air compressors normally in operation will be selected based upon a rotating schedule to equalize operating time. The rotation of operation also acts as an operational test of the compressor. Conformance to Regulatory Guide 1.5. (ASME Code, Section XI) is discussed in 6.6.

9.3.1.5 Instrumentation Requirements

Q. 211.052
(5.2.2)

Provide the initial values of all system and core parameters assumed in your analysis of pressure transients, including: (1) their nominal operating range; (2) their uncertainties; and (3) the operating limits on these parameters that will be established in the WNP-2 Technical Specifications.

Response:

The initial values of system and core parameters assumed in the overpressure analyses are listed in 5.2.2.2.2.1 of the FSAR. They are:

	Analysis Value	Nominal Value
a. Operating Power		
- MWt	3463.0	3323.0
- % NBR	104.2	100.0
b. Steam Flow		
- 10^6 lb/hr	14.98	14.29
- % NBR	105.0	100.0
c. Dome Pressure		
- psig	1020.0	1005.0

The operating power and steam flow are limited by the operating license to their nominal values. The effect of different operating dome pressure on overpressure protection is shown in the response to Question 211.050, which concludes that even with a dome pressure of 1063 psig, which is the allowable value for the proposed Technical Specification limit on high reactor pressure scram setpoint, the overpressure criteria would still be satisfied. Therefore, no Technical Specification limit on operating steam dome pressure is necessary.

Q. 211.053
(5.2.2)

In Section 5.2.2.2.4 of the FSAR, you discuss SRV characteristics which include valve groups and pressure setpoints. However, it is not apparent to us how these two items are factored into your analysis. For example, the setpoint range for the spring actuation safety mode is indicated in Section 5.2.2.2.4 as 1165 to 1205 pounds per square inch gauge (psig) whereas Table 5.2-2 lists 1130 to 1205 psig for this range. Define the phrase "valve groups" and indicate how you include consideration of valve groups in your analysis. Discuss how you use these different setpoint values in your analyses.

Response:

It is assumed that the question is directed to 5.2.2.2.2.4, Safety/Relief Valve Transient Analysis Specifications.

In the overpressure analysis described in 5.2.2.2.2.4, the valves are divided into five hypothetical groups or "valve groups" such that each group has 1/5 of the total calculated capacity. Within a group, the valves have the same opening and closing pressure setpoints.

The group pressure setpoints listed below are used in the overpressure analysis, while the valve setpoints shown in Table 5.2-2 are the specified nominal values. It is clear that the setpoints in the analysis are higher (i.e., more conservative) than the specified values. This is to account for initial setpoint errors and any instrument setpoint drift that might occur during operation.

Group	Setpoint
1	1177
2	1187
3	1197
4	1207
5	1217

Section 5.2.2.2.2.4 incorrectly states the setpoint range used in the transient analysis. It has been revised to reflect the values shown above.*

*Draft FSAR page change attached.

b. Pressure setpoint (maximum safety limit):

Spring-action safety mode - ~~1165~~ 1177 - ~~1205~~ 1217 psig

The setpoints are assumed at a conservatively high level above the nominal setpoints. This is to account for initial setpoint errors and any instrument setpoint drift that might occur during operation. Typically assumed setpoints in the analysis are 1 to 2% above the actual nominal setpoints. High conservative safety/relief valve response characteristics are also assumed.

5.2.2.2.2.5 Safety Valve Capacity

Sizing of the safety valve capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1375 psig) in response to the reference transients in 5.2.2.2.2.2.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety Valve Capacity

The required safety/relief valve capacity is determined by analyzing the pressure rise from a MSIV closure with flux scram transient. The plant is assumed to be operating at the turbine-generator design conditions at a maximum vessel dome pressure of 1020 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shutdown by the backup, indirect, high neutron flux scram. For the analysis, the spring-action safety setpoints are to be in the range of 1177 to 1217 psig. The analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME code allowable pressure in the nuclear system (1375 psig). Figure 5.2-4 shows curves produced by this analysis. The sequence of events in Table 5.2-10 assumed in this analysis was investigated to meet code requirements and to evaluate the pressure relief system exclusively.

Under the General Requirements for Protection Against Overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, credit can be allowd for a scram from the reactor protection system. In addition, credit is also taken for the protective circuits which are indirectly derived when determining the required safety/relief valve capacity. The back-up reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving dual purpose safety/relief valves. Application of the direct position

Q. 211.054
(5.2.2)

The peak pressures occurring after closure of the MSIV's due to scrams initiated by high flux and high pressure signals are not consistent between Figures 5.2-4 and 5.2-5 of the FSAR. Further, Section 5.2.2.2.3.1 erroneously states that generator load rejection with bypass failure is shown on Figure 5.2-4. Correct these inconsistencies.

Response:

The inconsistencies stated are corrected in revised 5.2.2.2.3.1 and revised Figures 5.2-4 and 5.2-5. The curve for peak vessel bottom pressure from pressure scram in Figures 5.2-4 and 5.2-5 were mistakenly placed onto these figures and have been deleted. The reference to generator load rejection with bypass failure in 5.2.2.2.3.1 was incorrect and has been deleted.*

*Draft revised FSAR page changes attached.

2

scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety/relief valve capacity of nuclear vessels under the provisions of the ASME code. The safety/relief valves are operated in a relief mode (pneumatically) at set points lower than those specified for the safety function. This ensures sufficient margin between anticipated relief mode closing pressures and valve spring forces for proper seating of the valves.

The parametric relationship between peak vessel (bottom) pressure and safety/relief valve capacity for the MSIV transient with high flux scram is described in Figure 5.2-4. Also shown in Figure 5.2-4 is the ~~parametric relationship between~~ peak vessel (bottom) pressure FOR POSITION SCRAM WITH 18 VALVES CAPACITY. ~~and safety/relief valve capacity for the generator load rejection with a coincident closure of the turbine bypass valves and direct scram, which is the most severe transient when direct scram is considered.~~ Pressures shown for flux scram will result only with multiple failure in the redundant direct scram system.

The time response of the vessel pressure to the MSIV transient with flux scram ~~and the generator load rejection with a coincident closure of the turbine bypass valves and direct scram for 18 valves~~ is illustrated in Figure 5.2-5. This shows that the pressure at the vessel bottom exceeds 1250 psig for less than 7 seconds.

5.2.2.2.3.2 Pressure Drop in Inlet and Discharge

Pressure drop on the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures.

Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent backpressure on each safety/relief valve from exceeding 40% of the valve inlet pressure, thus assuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each safety/relief valve has its own separate discharge line.

5.2.2.3 Piping and Instrument Diagrams

See Figure 5.2-6 which shows the schematic location of pressure-relieving devices. The schematic arrangement of the safety/relief valves is shown in Figures 5.2-7 and 5.2-8.

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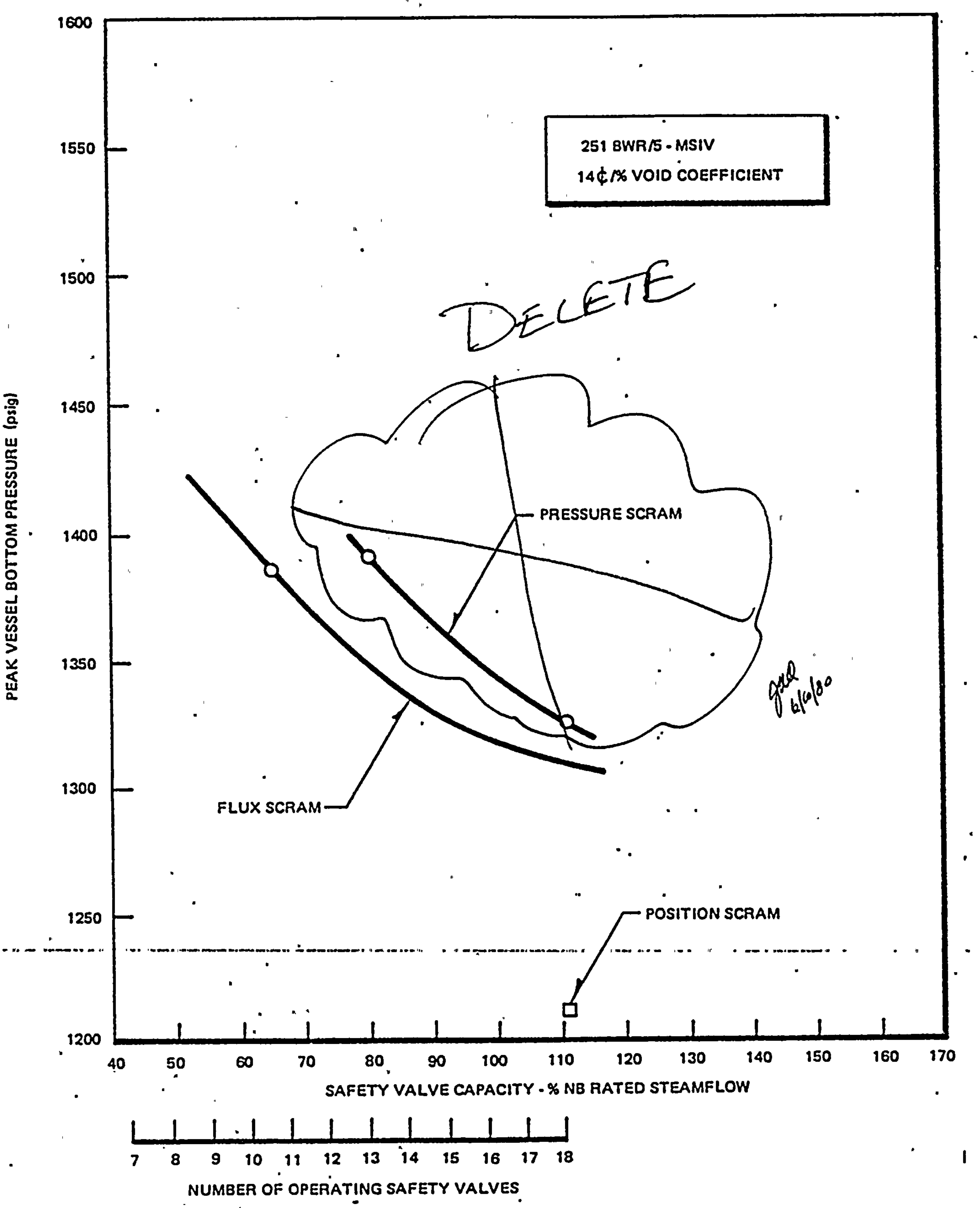
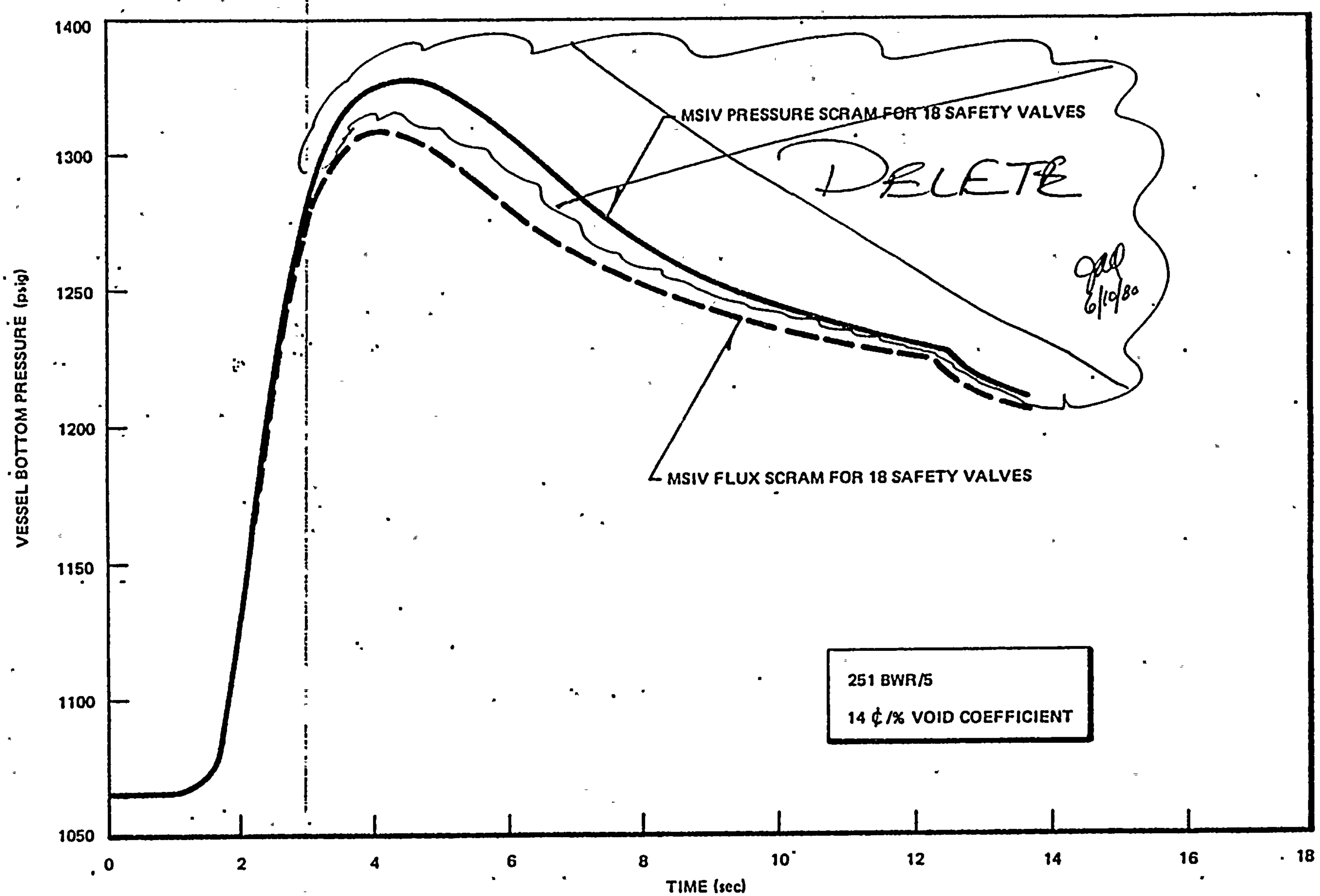


WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PEAK VESSEL PRESSURE VERSUS SAFETY/RELIEF CAPACITY	FIGURE 5.2-4

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2



PEAK VESSEL PRESSURE VERSUS TIME FOR SAFETY VALVE CAPACITY SIZING TRANSIENT

FIGURE 5.2-5

Q. 211.055
(5.2.2)

Indicate whether the WNP-2 facility will incorporate a fast scram system.

Response:

WNP-2 will not incorporate a fast scram.

Q. 211.056
(5.2.2)

Provide calculations to support the values you assume for the discharge coefficients and the flow capacities of the SRV's.

Response:

The values used for the average discharge coefficient and flow capacities are not assumed but rather were determined by experiment. The valve manufacturer, Crosby Valve and Gage Company located in Wrentham, Massachusetts, physically tested three different size valves of the type used at WNP-2 at three different popping pressures using saturated steam to obtain flow data for the valve type. These tests were performed in 1968 and the data obtained was submitted to the National Board of Boiler and Pressure Vessel Inspectors for certification. Certification was approved in November of 1971. The certification includes verification of the average discharge coefficient shown in paragraph 5.2.2.4.2.1. The following table gives the certified flow capacities for a Crosby-style HB pressure relief valve.

CROSBY VALVE & GAGE COMPANY
STYLE HB - Section III, Nuclear
(Formula: W = 51.5 x .966 x AP x .90)
Accumulation 3% per Section III

		Popping Press. Lbs.	Capacity Lbs. Per Hour
Inlet Size:	6 in.	50	47,789
		100	84,966
Bore Dia.:	4.530	200	159,321
		300	233,675
Area:	16.117	500	382,385
		1000	754,158
		1500	1,125,931

The experimental results verify the use of the ASME flow rate formula as used in Table 5.2-2.

$$\text{Flow Rate (LBM/HR)} = 51.5 \times 0.966 \times A \times P \times 0.90$$

Where A is the orifice area of the valve in squre inches and P is the absolute pressure at the upstream position of the valve measured in PSI.

It should be noted that the Crosby Style HB safety/relief valves used at WNP-2 have been returned to the manufacturer for design changes which will greatly improve the valves functional characteristics and reliability. The design changes do not affect discharge coefficient or flow capacities obtained experimentally for the valve.

Q. 211.057
(15.0)

Indicate the power-operated pressure relief setpoints and the flow capacities assumed in your transient analyses in Section 15 of the FSAR.

Response:

The relief setpoints are: 1091, 1101, 1111, 1121, 1131 (psig). The flow capacity of the 18 valves is 111.5% NBR at 1213 psig. The above information is listed in Table 15.0-2 of FSAR.

The individual relief valve capacity at 1213 psig is:

$$\frac{111.5\%\ \text{NBR}}{18} = 885{,}558\ \text{lbs/hr where NBR} = 14.296\ \text{meb/hr at 3323 MWth}$$

Now at the relief valve setpoints:

Nominal Setpoint, psig	Respective Capacity, lbs/hr
1091	798,000
1101	805,000
1111	812,000
1121	819,000
1131	826,000

Q. 211.058
(6.3)

Confirm that adequate net positive suction head (NPSH) will exist if operator action is not initiated within 20 minutes following a postulated loss-of-coolant accident (LOCA). Provide your detailed NPSH calculation to demonstrate conformance with our positions in Section C of Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps", November 1970, for the pumps in the emergency core cooling system (ECCS).

Response:

The ECCS NPSH calculation demonstrating conformance to Regulatory Guide 1.1 has been presented in the response to Question 022.038. The suppression pool temperature used in this calculation is 220°F. The available NPSH is 36 feet, using the unrealistic assumption of not taking credit for wetwell air space pressure being the vapor pressure of the suppression pool water at 220°F. The NPSH required by the RHR pumps, as documented by the pump performance curves (Figures 6.3-10a, b and c) is 11 feet at 7450 gpm rated flow. The NPSH required for the LPCS pump, as documented by the pump performance curve (Figure 6.3-8), is 12 feet at a maximum flow of 7800 gpm. The HPCS pump was tested by the manufacturer from 500 gpm to runout (7270 gpm) with an available NPSH of 31.6 feet and there was no evidence of cavitation. This is not considered the required NPSH, but it does verify the adequacy of the available NPSH.

The response to Question 211.062 addresses the affect on NPSH due to a drop in suppression pool water level from passive failures post-LOCA. About five days of operator action time is available before the NPSHA drops to 31.6 ft.

The 220°F peak suppression pool temperature predicted by the containment response and analysis presented in Section 6.2.1 assumes the following:

1. no containment heat removal for the first 10 minutes;

2. containment heat removal after 10 minutes assuming a full fouled RHR heat exchanger and rated RHR flow, 7450 gpm, through the shellside of the heat exchanger;

3. no credit taken for any heat losses other than through the RHR heat exchangers;

4. a conservative, steady 95°F standby service water (SW) temperature; and

5. a suppression pool volume of 107,850 $feet^3$.

No specific calculations on suppression pool temperature were performed to show the effects of starting long-term cooling 20 minutes after the accident. However, there are enough conservatisms in the suppression pool temperature analyses to justify the adequacy of the WNP-2 design if a 20-minute operator action time is used.

The assumption of no containment heat removal prior to operator action is not realistic. ECCS and Standby Service Water (SW) to ECCS components, including the RHR heat exchangers, are automatically started after receipt of the LOCA signal, even if off-site power is lost. The RHR system, which is used for long-term containment cooling, is automatically aligned to the low pressure coolant injection (LPCI) mode at the start of the accident. About 45% of the LPCI flow goes through the RHR heat exchanger, while the balance of the flow goes through the heat exchanger bypass valve F048 (reference Figure 5.4-13). Valve F048 automatically opens after a LOCA signal. Without any operator action, some containment cooling is initiated. In order to place the plant in a long-term cooling mode, all the operator has to do is close the RHR heat exchanger bypass valve F048. Even with only 45% LPCI flow through the RHR heat exchanger, 73% of the rated thermal conductivity is still available. The RHR heat exchanger's thermal conductivity is 229 BTU/sec °F with the reduced shell side flow as compared to 289 BTU/sec °F with rated shell side flow.

Because of the small temperature difference between the suppression pool and the ultimate heat sink during the early part of the transient, the RHR heat transfer rate is not high. Changing the assumption in the analysis presented in 6.2.1 of no containment cooling until 20

minutes results in less than 2°F increase in the suppression pool temperature 20 minutes after the start of the accident. This was determined by calculating the total heat removed by the RHR heat exchanger between 10 and 20 minutes after the accident and then adding that quantity of heat to the suppression pool mass. This small temperature increase will in turn result in less than 1°F increase in the peak suppression temperature, which occurs several hours later. This increase will not cause NPSH problems.

The assumption of a steady 95°F SW temperature is very conservative. Ultimate heat sink parametric studies have determined that if the realistic, although still conservative, SW transient presented in the response to Question 010.023 and presented in 9.2.5 is used, the peak suppression pool temperature will be approximately 10°F lower than predicted using a steady 95°F SW temperature.

In the ultimate heat sink temperature transient analysis in 9.2.5.3, the effect on suppression pool temperature transient was determined, assuming a fully fouled RHR heat exchanger, no operator action to close F048, and the predicted service water temperature response. This suppression pool transient is shown in Figure 9.2-7a, and it results in a suppression pool temperature less than 220°F.

As shown in Table 6.2-1, the actual minimum suppression pool volume outside the pedestal is 127,197 feet^3, not the 107,850 feet^3 used in the analysis. The latter figure is used to maximize the initial blowdown effects after a LOCA and does not include the water volume more than 12 feet below the downcomer exits. Since the maximum calculated suppression pool temperature does not occur until about 16 hours after the accident (reference Figure 6.2-8), credit can be realistically taken for all the water outside the pedestal area, i.e., 127,197 feet^3.

Therefore, there is enough conservatism in the suppression pool temperature transient analysis to show that even with an assumed 20-minute operator time, the suppression pool will remain below 220°F, and at 220°F, there is adequate NPSH available in accordance with Regulatory Guide 1.1 to operate the ECCS pumps.

Q. 211.059
(6.3)

You state in the FSAR that no operator action is required until 10 minutes after an accident. However, it is our position that no operator action should be required for 20 minutes after an accident. Accordingly, discuss the consequences of the reactor operator not performing his required duties until 20 minutes after a postulated LOCA. Discuss all actions which the operator is required to perform to place the plant in the long-term cooling mode following a postulated LOCA.

Response:

As indicated in Section 6.3.2.8, no operator actions are assumed for 10 minutes after a postulated LOCA. Of the five criteria specified in Section 50.46 and Appendix K to 10 CFR 50, the maximum peak cladding temperature, maximum cladding oxidation, maximum hydrogen generation, and transients which might jeopardize maintaining coolable geometry all occur before 10 minutes for the design-basis accident.

The only criterion not met in less than 10 minutes is that of maintaining long-term cooling. This latter criterion is met by the initiation of the suppression pool cooling mode. As explained in Section 6.2.2.3 and in the response to Question 211.58, the only action the operator must perform to place the plant in a long-term cooling mode is to close the RHR heat exchanger bypass valve F048 (Reference Figure 5.4-13). As shown in the response to Question 211.058, there is enough conservatism in the suppression pool transient analysis to show that even with an assumed 20-minute operator action time, the suppression pool will remain below 220°F, and at 220°F, there is adequate NPSH available in accordance with Regulatory Guide 1.1 to operate the ECCS pumps.

The only type of loss-of-coolant accident which would require operator action is a break outside the containment in a line connected directly with the reactor pressure vessel. Operator action is required to activate the automatic depressurization system if HPCS is not available because there will be no high drywell pressure signal. Then the low pressure ECCS can terminate the transient. The maximum steam line break (MSLB) is representative of this class of break. A discussion for assuming a 20-minute operator action time after a MSLB is presented in the response to Question 211.065. The conclusion is that the peak cladding temperature only reaches about 1250°F, far below the 2200°F limit.

Q. 211.060
(6.3)

On page 6.3-10 of your FSAR, you state that the high pressure core spray (HPCS) is automatically shutdown by a signal indicating a high water level in the reactor pressure vessel (RPV). Indicate what provisions are incorporated in the WNP-2 facility to prevent premature termination of the HPCS flow. State whether any interlocks are provided (e.g., a LOCA signal) which would prevent automatic shutoff.

Response:

Premature termination of HPCS flow prior to attaining high water level (level 8, per Figure 5.2-6) is prevented by a requirement that the level 8 high level trip consist of a two-out-of-two logic permissive to close the HPCS injection valve MO-F004 (Reference Figure 6.3-2). LOCA logic does not prevent automatic shutoff on level 8. If water level decreases to level 2 after HPCS flow has been shut off, the HPCS injection valve will automatically reopen. The logic for MO-F004 is shown in FSAR Figure 7.3-8., High Pressure Core Spray FCD, Sheet 1.* During the time the injection valve is closed, the HPCS pump is circulating flow to the suppression pool.

* Fig reference is for revised Ch 7.

Q. 211.061
(6.3)

When the water level in the condensate storage tanks (CST) drops to a predetermined level, the HPCS pump switches automatically to the suppression pool. Provide assurance that the water level in the CST will supply an adequate NPSH at the time this switchover occurs. In addition, show that the minimum submergence of the suction piping in the CST will preclude formation of an undesirable vortex. Describe the preoperational testing you will perform to demonstrate that such vortex formation will not occur.

Response:

During performance testing of the HPCS pump, no direct measurement of the required NPSH was obtained. However, in lieu of a direct measurement of the required NPSH, the pump was tested with the available NPSH held constant at approximately 31.6 feet (reference centerline suction nozzle) for flows ranging from 519 gpm to 7255 gpm (runout). During these tests no evidence of cavitation in the pump was detected. Although this is not considered the required NPSH, it does indicate that the 31.6 feet used in the tests meets or exceeds the required NPSH for the full flow range of the pump. The rated HPCS pump flow is 6856 gpm with the RPV pressure 20 psi above primary containment pressure, and 1550 gpm with the RPV pressure 1130 psi above the pressure at the source of suction. The available NPSH to the HPCS pump at suction transfer from the CST to the Suppression Pool is calculated using the following data:

a) atmospheric pressure, 14.7 psia, above the CST's.

b) vapor pressure, 1.7 psia, conservatevely assuming the CST's are at 120 F.

c) pressure drop due to friction, 7.2 feet, for a flow of 6856 gpm.

d) static head when the CST's are at 447'4" (switchover level), 26.96 feet. (pump suction C.L. el. 420'-4&1/2")

The available NPSH is 49.8 feet which is significantly greater than the performance test parameter of 31.6 feet.

The HPCS pump is guaranteed a continuous suction supply during suction switchover, since the suppression pool suction supply valve is designed to open on a low level signal from the CST's. Once the suppression pool suction supply valve is fully open, the suction supply valve from the CST's is automatically closed. Refer to figure 6.3-1 for the HPCS valving configuration.

The suction piping in the CST's is being reviewed to determine if vortexing will be a problem under any operating mode of the HPCS. This response will be revised upon completion of that review. In any case, subsequent preoperational testing will verify the absence of vortexing in accordance with the calculations.

Q. 211.062
(6.3)

Provide assurance that adequate NPSH exists in the event of a passive failure of the ECCS in a water-tight pump room. Discuss the possibility of vortex formation at the suction intake of the remaining ECCS pumps with the lowered suppression pool level that would result from this type of postulated accident. Discuss the preoperational tests you will perform to demonstrate that ther is no impairment of the functional capability of the ECCS due to a lowered suppression pool level.

Response:

Passive failures in ECCS piping and their affects on available NPSH were previously addressed in the response to Question 212.003. In this response, it was determined that the operator has approximately 5 days to detect and isolate any ECCS passive failure before the suppression pool drops below the minimum level required for ECCS pump requiring the most NPSH, which is the HPCS pump (31.6 ft). See the response to FSAR Question 211.061 for further information on NPSHR. Five days represent more than enough time to isolate any leaks, since the safety grade level alarm system in the ECCS pump rooms will alert the operator to ECCS room flooding prior to any significant loss of suppression pool water level.

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 inches) to reduce the inlet velocity (maximum 6.67 ft/sec). This inlet velocity will support a vortex of no more than 2-1/2 feet in height. The inlet to each of the ECCS suction lines is greater than 22 feet below the minimum suppression pool level. Vortex formation at the ECCS pump inlets as a result of lowered suppression pool level is thus not considered a problem.

Since it has been conservatively established that all ECCS suction lines are adequately submerged to preclude formation of an undesirable vortex, no confirmatory preoperational testing will be performed.

Q. 211.063
(6.3)

Confirm that the low pressure coolant injection (LPCI) system does not perform any other function such as containment cooling during the short-term portion of the recovery phase following a postulated LOCA. If the LPCI system will be used for another function during this time period, this additional function must be considered in your LOCA analyses. (Refer to Question 211.082 of this enclosure.)

Response:

A LOCA signal, which automatically initiates the LPCI mode of RHR system, is also used to isolate all other modes of RHR operation and revert system valves to LPCI line up. The RHR system continues in the LPCI mode until the operator determines that another mode of operation is needed (such as containment cooling) and takes action to manually initiate that mode. By training, the operator will not divert LPCI to any other mode of operation for ten minutes. No operator actions are needed during the short-term (see also Section 6.3.2.8 and 6.2.2.2).

Q. 211.064

Provide the values of the total break area which you assumed for the following postulated breaks: (1) the recirculation line break; (2) the steam line break inside and outside containment; (3) the feedwater line break; and (4) the core injection spray line break.

Response:

The maximum recirculation break area of 3.113 ft^2 is comprised of the following areas: recirculation safe end area (2.565 ft^2), total jet pump nozzle area of one recirculation loop (0.468 ft^2), and the minimum flow area of the reactor water cleanup system piping connecting the two loops (0.080 ft^2).* As explained in 6.2.1.1.3.3.2, the maximum steam line break inside the containment is initially based on the steam line safe end area (3.05 ft^2) plus the minimum flow restrictor area (0.91 ft^2). After the main steam isolation valves have closed, the flow is limited by critical flow through the safe end. This is shown in Figure 6.2-10. The maximum outside steam line break area (3.65 ft^2) is based on the minimum flow limiter area for each steam line (0.91 ft^2). The feedwater line break area (0.362 ft^2) is based on the inside area of the feedwater sparger pipe (0.181 ft^2). The maximum core spray line break area is based on the limiting area of the core spray line safe end (0.47 ft^2).

* draft FSAR page change attached

TABLE 6.3-2

SIGNIFICANT INPUT PARAMETERS TO THE

LOSS-OF-COOLANT ACCIDENT ANALYSIS

A. PLANT PARAMETERS:

Core Thermal Power	3462 MWt which corresponds to 105% of rated steam flow*
Vessel Steam Output	15.01×10^6 Lbm/h which corresponds to 105% of rated steam flow
Vessel Steam Dome Pressure	1055 psia
Recirculation Line Break Area for Large Breaks ($ft.^2$)	~~3.106~~ 3.113 (DBA) and 1.0
Recirculation Line Break Area for Small Breaks ($ft.^2$)	1.0 and 0.10

B. FUEL PARAMETERS:

Fuel Type	Initial Core
Fuel Bundle Geometry	8 x 8c 62 fueled rods
Peak Technical Specification Linear Heat Generation Rate (kw/ft)	13.4
Design Axial Peak Factor	1.4
Initial Minimum Critical Power Ratio	1.18

A more detailed list of input to each model and its source is presented in Reference 6.3-2.

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*This power level exceeds the Appendix K requirement of 102%. The core heatup calculation assumes a bundle power consistent with operation of the highest powered rod at 102% of its maximum (technical specification) linear heat generation rate.

TABLE 6.3-3

SUMMARY OF RESULTS OF LOCA ANALYSIS

Break Size Location Single Failure		PCT (^{o}F)	Peak Local Oxidation
Break Spectrum Analysis[1]			
~~3.106~~ 3.113 ft^2 (DBA) Recirc. Suction LPCI D/G failure		1960	1.1
1.0 ft^2 Recirc. Suction LPCI D/G failure HPCS D/G failure	Large Break Methods	 1568 1675	 <1.0
LPCI D/G failure HPCS D/G failure	Small Break Methods	1100 1385	<1.0
0.1 ft^2 Recirc. Suction HPCS D/G failure		1473	<1.0

The corewide metal-water reaction for the subject plant has been calculated using method 1 described in Reference 6.3-2. The calculation was done using the standard nodal power distribution consistent with the assumption of 102% of licensed core power. The value is 0.07%.

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(1) For other breaks in spectrum see lead plant analysis, Reference 6.3-3. For justification of selection of lead plant, see Reference 6.3-1.

Q. 211.065
(6.3)

Indicate the differences between the assumed values of break areas for postulated steam line breaks inside and outside containment. Your analyses of these postulated breaks indicates that the reactor core could become uncovered if no operator action took place within 20 minutes after this postulated accident. Indicate the effect on the peak clad temperature if the operator takes no action for 20 minutes after an accident. In your response, include a discussion of all your assumptions.

Response:

The difference between the assumed values of break areas for postulated steam line breaks inside and outside containment is explained in Section 6.2.1.1.3.3.2 and in the response to Question 211.064. The maximum steam line break inside containment is initially based on the steam line safe end area (3.05 ft^2) plus the minimum restrictor area (0.91 ft^2). After the main steam isolation valves have closed, the steam flow is limited by critical flow through the safe end. This is shown in Figure 6.2-10. The maximum outside steam line break area (3.65 ft^2) is based on the sum of the minimum flow restrictor areas for each steam line (0.91 ft^2).

Any break outside the primary containment in a line connecting directly to the reactor pressure vessel will need operator action under loss-of-coolant accident (LOCA) analysis assumptions because there will be no high drywell pressure signal to activate the automatic depressurization system (ADS). Given LOCA analysis assumptions, no credit is taken for the feedwater system and the reactor core isolation cooling (RCIC) system. Also, the high pressure core spray (HPCS) system is assumed to fail. With no credit for the above systems, the operator must manually initiate the ADS to depressurize the vessel below the shutoff head of the low pressure ECC systems, allowing these systems to terminate the transient.

The outside steam line break is representative of this class of breaks. A complete analysis of the outside steam line break assuming no operator action for 20 minutes is presented in the response to LaSalle Question 212.098. Briefly summarizing that analysis, no operator action was assumed

until 20 minutes after a maximum steam line break outside the containment. This resulted in a peak cladding temperature of about 1250°F, far below the 2200°F limit. It is appropriate to apply the LaSalle analysis to WNP-2 because the two plants are identical in size and have the same ECC system design and therefore will exhibit LOCA characteristics that are very similar. Significant margin is demonstrated in the LaSalle case to account for any minor differences between the two plants.

Q. 211.066
(6.3)

Identify all ECCS valves which may be potentially submerged or subject to spray impingement following a postulated LOCA. Discuss the environmental qualification ofthese valves for these conditions:

Response:

The below listed valves represent the ECCS systems valves inside containment required for safe shutdown following a LOCA which may be subject to spray impingement following a postulated LOCA:

Valve No.	Type	Qty.	System
HPCS-V-5	Testable Check Valve	1	High Pressure Core Spray
HPCS-V-51	Gate Valve	1	High Pressure Core Spray
LPCS-V-6	Testable Check Valve	1	Low Pressure Core Spray
LPCS-V-51	Gate Valve	1	Low Pressure Core Spray
RHR-V-41A,B,C	Testable Check Valve	3	Low Pressure Coolant Injection
RHR-V-111A,B,C	Gate Valve	3	Low Pressure Coolant Injection
MS-RV-3D,4A,4B 4C, 4D, 5B, 5C	Safety/Relief Valves	7	Automatic Depressurization System

None of the above listed valves are subject to flooding following a postulated LOCA because all the water released by the LOCA will flow to the suppression pool and all the listed valves are above the drywell floor.

The safety/relief valves, testable check valves and gate valves listed above and associated components are designed to be suitable for the following accident thermal environment:

Temperature	340°F	320°F	250°F	200°F
Pressure	-2 to 45 psig	-2 to 45 psig	-2 to 25 psig	-2 to 20 psig
Relative Humidity	100%	100%	100%	100%
Duration	3 hrs.	6 hrs.	1 day	100 days

In addition, they have been designed to be operable during and after an SSE.

The gate valves listed above are maintenance valves and are normally locked open. Although they are designed to be operable, they are not required to operate following an accident. The only electrical components on these valves are the limit switches, which are utilized to provide verification that these valves are open during normal plant operation. Therefore there is no effect on the operation of the ECCS if these valves are subject to jet impingement following a postulated LOCA.

The testable check valves are equipped with an air operator to allow valve stroking during plant shutdown and thus verify operability. This air operator is designed so that it will not prevent the check valve from opening for forward flow or closing to prevent reverse flow. The only electrical components on these valves are the stem actuated limit switches which provide position indication of the air operator rod, and magnetic sensors which provide position indication of the valve disc. The solenoid valve for the air operators and control element for the magnetic sensors are located outside primary containment. Therefore there is no effect on the operation of the ECCS if these valves are subject to jet impingement following a postulated LOCA.

The ADS valves are not designed for operability after steam jet impingement. However, WNP-2 is currently evaluating the consequences of jet impingement on the ADS valves. If the analysis shows that the results are unsatisfactory, then the ADS valves will be protected from jet impingement. The results of this analysis will be reported by amendment to Chapter 3.6.

Q. 211.C67
(6.3)

Indicate whether there have been any recent changes or corrections to your ECCS analysis. If so, provide the references for the latest model changes and corrections in the list of references provided for your ECCS analysis.

Response:

The additional references required for the latest model changes and corrections to Section 6.3.6 are as follows:

6.3-4 "Safety Evaluation for General Electric ECCS Evaluation Model Modifications," letter from K. R. Goller (NRC) to G. G. Sherwood (GE), dated April 12, 1977

6.3-5 Letter, A. J. Levine (GE) to D. F. Ross (NRC) dated January 27, 1977, "General Electric (GE) Loss-of-Coolant Accident (LOCA) Analysis Model Revisions - Core Heatup Code CHASTE05."

6.3-6 Letter, A. J. Levine (GE) to D. B. Vassallo (NRC), dated March 14, 1977, "Request for Approval for Use of Loss-of-Coolant Accident (LOCA) Evaluations Model Code REFLOOD05."

Section 6.3.3.7.1 has been revised for the SAFE/REFLOOD and CHASTE model descriptions to include the appropriate references above. References 6.3-4 and 6.3-6 apply to SAFE/REFLOOD and references 6.3-4 and 6.3-5 apply to CHASTE.*

*Draft FSAR page changes attached.

LONG-TERM THERMAL HYDRAULIC MODEL AND REFILL/REFLOOD MODEL (SAFE/REFLOOD)

The SAFE/REFLOOD code is a model which is used to analyze the long-term thermodynamic behavior of the coolant in the vessel. The SAFE/REFLOOD code calculates the uncovery and reflooding of the core and the duration of spray cooling and (for small breaks) the peak cladding temperature.

For a detailed description of the model and a discussion regarding sources of input to the model refer to the "SAFE code and REFLOOD Code Documentation" Sections II.A.1 and II.A.2 of Reference 6.3-2, and References 6.3-4 and 6.3-6.

CORE HEATUP MODEL (CHASTE)

The CHASTE code solves the transient heat transfer equations for specific axial planes of each fuel bundle type, for large breaks. CHASTE receives input from SCAT, SAFE and REFLOOD and calculates cladding temperatures and local cladding oxidation during the entire LOCA transient. For a detailed description of the CHASTE model and a discussion regarding sources of input, refer to the "CHASTE code documentation" Section II.A.5 of Reference 6.3-2, and References 6.3-4 and 6.3-5.
The significant input variables used by the LOCA codes are listed in Table 6.3-2.

6.3.3.7.2 Accident Description

A detailed description of the LOCA calculation is provided in Reference 6.3-2. For convenience, a short description of the major events during the design basis accident (DBA) is included here.

Immediately after the postulated double-ended recirculation suction line break, vessel pressure and core flow begin to decrease. The initial pressure response (Figure 6.2-21b) is governed by the closure of the main steam isolation valves and the relative values of energy added to the system by decay heat and energy removed from the system by the initial blowdown of fluid from the downcomer. The initial core flow decrease (Figure 6.3-18) is rapid because the recirculation pump in the broken loop looses suction and almost immediately ceases to pump. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds. When the jet pump suctions uncover, calculated core flow decreases to near zero. When

6.3.6 REFERENCES

6.3-1 Compliance with Acceptance Criteria of 10 CFR 50.46 Letter G. L. Gyorey to V. Stello, May 12, 1975.

6.3-2 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K, "NEDO-20566 submitted August 1974, and "General Electric Refill Reflood Calculation" (Supplement to Safe Code Description) transmitted to US NRC by letter, G. L. Gyorey to Victor Stello, Jr., dated December 20, 1974.

6.3-3 William H. Zimmer Nuclear Power Station, Unit 1; FSAR (Section 6.3) docket number 50-358.

6.3-4 "Safety Evaluation for General Electric ECCS Evaluation Model Modifications" letter from K.R. Groller (NRC) to G.G. Sherwood (GE), dated April 2, 1977.

6.3-5 Letter, A.J. Levine (GE) to D.F. Ross (NRC) dated January 27, 1977, "General Electric (GE) Loss-of-Coolant Accident (LOCA) Analysis Model Revisions - Core Heatup Code CHASTE05".

6.3-6 Letter, A.J. Levine (GE) to D.B. Vassallo (NRC), dated March 14, 1977, "Request for Approval for Use of Loss-of-Coolant Accident (LOCA) Evaluations Model Code REFLOOD05."

Q. 211.068
(6.3)

Justify the designation in Table 6.3-3 of the FSAR, of the Zimmer facility as the lead plant for the WNP-2 facility with respect to the LOCA break spectrum analysis. Our concern is that the Zimmer fuel assembly is an 8x8 fuel array with one water rod while the WNP-2 fuel assembly will be an 8x8, two water rod array.

Response:

The Zimmer LOCA analysis is an appropriate representative break spectrum analysis for WNP-2 because the LOCA characteristics of similar plants of a given product line are similar. The lead plant analysis serves to identify the limiting failures and breaks and to define the LOCA characteriscis for like plants. Individual plant specific analyses are then provided at these points to define the specific plant response for the limiting cases. The location of the limiting break is insensitive to changes in power level or fuel type. This is the basis of the lead plant concept.

Q. 211.069
(6.3)

Correct the small break model curves shown on Figure 6.3-13 of the FSAR for both the failure of the diesel-generator which disables the LPCI and the diesel-generator failure which disables the low pressure core spray (LPCS). Specifically, correct the apparent inconsistency between the values of peak clad temperature (PCT) in Figures 6.3-32 and 6.3-39 of the FSAR and those in Figure 6.3-13 at a break area equal to 80 percent of the break area for the design basis accident (DBA) and at 60 percent of DBA break area.

Response:

The small break model curves shown on Figure 6.3-13 for both the failure of the diesel-generator which disables LPCI and the diesel-generator which disables LPCS are correct. Some confusion may have arisen because at the 0.5 ft^2 break size, the two curves appear to intersect, which they do not. They intersect only at the 0.8 ft^2 (approximate) break size.

The PCT curves shown in Figures 6.3-32 and 6.3-39 are taken from the Zimmer lead plant analysis for BWR/5's. The curve in question in Figure 6.3-13 shows the plant specific results at the limiting points of the break spectrum determined by the lead plant analysis and shows that the rest of the spectrum is less limiting than the DBA. Figures 6.3-32 and 6.3-39 from the lead plant analysis are included in the FSAR as representative results for non-limiting breaks. For further discussion of the lead plant concept, refer to Question 211.068.

Q. 211.070
(6.3)

Demonstrate that a postulated failure of the HPCS in conjunction with a postulated break whose area ranges from 1.0 square foot to the DBA break area is not more limiting than the postulated failure of the diesel-generator which disables the LPCI system over the same range of break areas.

Response:

In the large break region, the single failure which disables the greatest number of ECCS systems is in general the most limiting. In the large break region, substantial amounts of initial vessel inventory are lost through the break during the blowdown. With fewer systems available, there is less ECCS flow available for reflooding the core and the core will reflood later. The later reflooding results in higher peak cladding temperatures. Thus the failure of either diesel which powers two low pressure ECC pumps is more severe than the failure of the HPCS system which involves the loss of only one pump.

The current Section 6.3.3 of the WNP-2 FSAR is composed of "typical" results representative of any BWR/5. The plant specific LOCA analysis for WNP-2 has not been completed. When the plant specific analysis is complete, the limiting failure for the break spectrum from 1.0 ft^2 to the DBA will be supplied. Plant specific analyses are delayed for incorporation into the FSAR to take advantage of ECCS model improvements which naturally occur as time progresses. The normal time for submittal of these analyses has been approximately six months before fuel load.

Q. 211.071
(6.3)

Indicate why the plots of water level versus time for the 1.0 square foot transition break assuming a failure of the HPCS system are different for the small break method and the large break method.

Response:

The difference in the water level plots for the 1.0 square foot transition break is due to the differences in the vaporization and the void calculations between the small and large break models in the REFLOOD code.

The two most significant differences between the small and large break models are:

a. Use of the Vaporization Correlation: The vaporization of spray water in the core during the period when core sprays are operating is calculated using a bounding correlation. The correlation requires the Peak Cladding Temperature, PCT, at time of spray initiation. The LBM correctly uses a constant value whereas the SBM conservatively uses a continuously increasing value. This difference generally results in a more conservative calculation of the reflooding time using the small break model.

b. Level and Vaporization Following Bottom Reflooding: The LBM uses an empirically based void fraction of 0.50 for calculating the level and the vaporization below the level. The SBM uses the conservative fuel rod heatup model with a reflooding heat transfer coefficient to calculate the level and the vaporization below the level. This difference generally results in a more conservative calculation of the reflooding time using the SBM.

A further discussion of the small and large break models of the REFLOOD code is contained in FSAR Reference 6.3-2, "General Electric Company Analytical Model for Loss of Coolant Analysis in Accordance with 10CFR50, Appendix K (NEDO-20566)".

Q. 211.072
(6.3)

Provide information on applicable tests which demonstrate that the pumps used for long-range cooling, both for normal operation and following a postulated LOCA, will operate effectively during the time period required to fulfill their function.

Response:

The RHR pumps and LPCS pumps are used for long-term cooling. Tests to which these pumps are subjected for operability assurance and performance have been described in the response to Question 211.42.

GE operating experience of Ingersoll-Rand ECCS pumps is as follows:

Hatch 2	RHR Pump	2A	864	hours
		2B	1,112	hours
		2C	629	hours
		2D	569	hours
	LPCS Pump	2A	13.5	hours
		2B	11.8	hours
Chinshan 1	RHR Pump		100	hours
	Core Spray Pump		30	hours
Chinshan 2	RHR Pump		75	hours
	Core Spray Pump		20	hours

No problems have been reported on these pumps.

Pump design principles applied by Ingersoll-Rand to these units are not unique. Assurance of a predictable functional reliability is also provided by a history of design, production, and application of pumps for similar pumping requirements in other nuclear and non-nuclear applications.

Q. 211.073
(6.3)

Table 6.3-5 is not clear. Discuss the intent of the column headed, "Effect on ECCS", with regard to the particular break location; i.e., indicate the postulated break location.

Response:

Table 6.3-5 has been deleted because the information is also included in revised Table 6.3-7. In 6.3.2.5 of the FSAR text, the reference to Table 6.3-5 has been changed to refer to the revised Table 6.3-7.*

*Draft FSAR page changes attached.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in 6.1. Nonmetallic materials such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials, etc., are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical and nuclear effects. Materials used were reviewed and evaluated and found to be acceptable with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A single failure analysis shows that no single failure prevents the starting of the ECCS when required, or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single failure proof with the exception of the ADS, hence it is expected that single failures will disable individual systems of the ECCS. The most severe effects of single failures with respect to loss of equipment occur if the loss-of-coolant accident results from an ECCS pipe break and is coincident with a loss of off-site power. The consequences of the most severe single failures are shown in Table 6.3-~~8~~. 7

For protection against and mitigation of passive ECCS failures, for Class 1E level instrument is mounted just above floor level in each ECCS pump room to detect the failures during long-term cooling, assuming loss of the other non-Class 1E leak detection equipment. See 3.4 for more details. The maximum leak rate postulated is 23 gpm, which is caused by the total failure of an RHR pump seal. With this leak, at least 44 hours is available for operator action after detection of the leak to identify and isolate the source before it has any additional adverse effects on ECCS operation.

The functional testing and calibration of the ECCS will be performed in accordance with the schedules established in Chapter 16, Technical Specifications. These schedules will be based on the requirements defined in the Standard Technical Specifications for BWR's.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

DELETE

TABLE 6.3-5

SINGLE FAILURE ANALYSIS

Single Failure	Effect on ECCS	Remaining ECCS[1]
Loss of HPCS	Loss of one of two depressurization and loss of one of three coolent delivery systems	ADS + 1 LPCS + 2 LPCI loops, or ADS + 3 LPCI loops operative
Loss of one diesel generator	Loss of HPCS	ADS + 1 LPCS + 2 LPCI loops, or ADS + 3 LPCI loops operative
	Loss of LPCS and one LPCI loop	ADS + HPCS + 1 LPCI loop, or ADS + 2 LPCI loops operative
	Loss of 2 LPCI loops	ADS + LPCS + 1 LPCI loop, or ADS + HPCS + LPCS, or ADS + LPCS + 1 LPCI loop operative
Loss of one division of dc power	Loss of HPCS	ADS + 1 LPCS + 2 LPCI loops, or ADS + 3 LPCI loops operative
	Loss of LPCS and one LPCI loop. Loss of one ADS logic control path	ADS + HPCS + 1 LPCI loop, or ADS + 2 LPCI loops operative
	Loss of 2 LPCI loops	ADS + HPCS + 1 LPCI loop, or ADS + HPCS + LPCS, or ADS + LPCS + 1 LPCS loop operative

(1) See 6.3.2.5, in addition to the failure postulated, the pipe break is assumed to be in an ECCS line disabling that subsystem.

6/10/80

TABLE 6.3-7

SINGLE FAILURE EVALUATION

The following table shows the single, active failures considered in the ECCS performance evaluation.

Assumed Failure	(RECIRC Suction Break) Systems Remaining*
LPCI Diesel Generator (D/G)	All ADS, HPCS, LPCS, 1 LPCI
LPCS D/G	All ADS, HPCS, 2 LPCI
HPCS D/G	All ADS, LPCS, 3 LPCI
One ADS Valve	All ADS minus one, LPCS, HPCS, 3 LPCI

Other postulated failures are not specially considered because they result in the same or less impact on ECCS capacity.

* SYSTEMS REMAINING, AS IDENTIFIED IN THIS TABLE, ARE APPLICABLE TO ALL NON-ECCS LINE BREAKS. FOR A LOCA FROM AN ECCS LINE BREAK, THE SYSTEMS REMAINING ARE THOSE LISTED, LESS THE ~~AFFECTED~~ ECCS SYSTEM in which the break is assumed.

gtl 6/10/80

Q. 211.074
(6.3)

Check valves in the discharge side of the HPCS, the LPCI/RHR and the LPCS systems perform an isolation function since they protect these low pressure systems from the high pressures in the reactor. We require that: (1) these check valves be classified as ASME IWV-2000, Category AC; and (2) the leak testing for these valves be performed according to the applicable code specifications. You should recognize that a test which simply draws suction on the low pressure side of the outermost check valves, will not be acceptable. Such a test only verifies that one of the check valves in series is fulfilling its isolation function. The required testing frequency is that specified in the ASME Boiler and Pressure Vessel Code, except in those cases where only one or two check valves separate high and low pressure systems. In these cases, we require that you perform leak testing of these valves at each refueling after the valves have been exercised. Accordingly, identify all ECCS check valves which should be classified as Category AC in accordance with our position on this matter. Verify that you will perform the required leak testing in accordance with the required frequency and that you have the necessary test lines to leak test each valve. Provide the leak detection criteria that you propose for the WNP-2 Technical Specifications.

Response:

The valves enumerated below are check valves which separate a low pressure system from reactor pressures. These valves are ASME Section XI, IWV-2000, Category AC valves: LPCS-V-6, RHR-V-41A, RHR-V-41B, RHR-V-41C, RHR-V-50A, and RHR-V-50B.

To assure that these valves adequately protect the low pressure systems, they will be tested as part of the WNP-2 Pump and Valve Test Program in accordance with the requirements of ASME Section XI, IWV-3000. This program and the appropriate leak detection criteria will be submitted for your review in accordance with the response to Question 110.034. The test line arrangement for the valves in question is shown in Figures 6.2-31l and 6.2-31m.

Q. 211.075
(6.3)

Indicate the provisions incorporated in the WNP-2 facility to protect the water level instrumentation for the CST and the lines from this tank leading to the HPCS systems from the effects of cold weather and dust storms. In responding to this item, cross-reference your responses to Items 010.16 and 211.12.

Response:

The water level instrumentation for the CST and the lines from this tank leading to the HPCS system are totally protected from the effects of cold weather and dust storms. The lines are electrically heat traced and a Seismic Category I enclosure has been provided for all tubing and instrumentation. All level instrumentation shall be NEMA type 4 rated (watertight and dust-tight indoor and outdoor).

See also the response to Question 211.12. The response to Question 10.16 does not address the concerns of this question. The safety related instrumentation necessary for switchover of HPCS and RCIC pump suction from the CST is located indoors and, as such, is not directly affected by cold weather or dust storms.

Q. 211.076
(6.3)

Some of the ECCS relief valve discharge lines penetrate primary containment and have outlets below the surface of the suppression pool. Since these lines are part of the primary containment boundary, we are concerned that excessive dynamic loads resulting from water hammer during actuation of the relief valves may cause cracking or rupture of these lines. Accordingly, identify these lines which penetrate the primary containment. Provide information concerning the measures you are taking to prevent line damage due to water hammer.

Response:

The ECCS relief valves shown on Table Q211.076-1 have discharge lines which penetrate the primary containment and have discharges below the suppression pool water level (Reference Figures 5.4-13a, 5.4-13b, 6.3-1, 6.3-5).

All safety/relief valves are purchased to ASME III, Class 2 requirements to match the requirements of the piping they are protecting. As such, the setpoint tolerance is ±3%, per ASME III, Section NC-7513.1.

For discussion on dynamic loads resulting from water hammer for RHR-RV-55(A,B) (E12-F055A,B), RHR-RV-95(A,B), and RHR-RV-36 (E12-F036) see response to Question 211.040. The remaining relief valves are installed to accomodate thermal expansion and leakage across closed valves in isolated piping systems. Pressure buildups in isolated lines will be slow and discharges from the relief valves in these lines will be small. Water hammer and other hydrodynamic loads are not considered a potential problem in these lines.

Table Q211.076-1

Relief Valve	Setpoint/Capacity	Location	Piping Design Pressure
E21-F018	550 psig/100 gpm	LPCS Discharge Leg Relief	550 psig
E21-F031	100 psig/ 10 gpm	LPCS Suction Leg Relief	100 psig
E22-F035	1575 psig/25 gpm	HPCS Discharge Leg Relief	1575 psig
E22-F014	100 psig/ 10 gpm	HPCS Suction Leg Relief	100 psig
E12-F025(A,B,C)	500 psig/ 25 gpm	RHR Discharge Leg Relief	500 psig
E12-F088(A,B,C)	125 psig/ 10 gpm	RHR Suppression Pool Suction Relief	220 psig - A,B 125 psig - C
E12-F005	220 psig/ 25 gpm	RHR Shutdown Cooling Suction Relief	220 psig
E12-F030	125 psig/ 10 gpm	RHR Flush Line Relief	125 psig
E12-F055(A,B)	500 psig/330,000 lb/hr	RHR Heat Exchanger Steam Relief	500 psig
RHR-RV-95(A,B)*	500 psig/330,000 lb/hr	RHR Heat Exchanger Steam Relief	500 psig
RHR-RV-1(A,B)**	500 psig/ 20 gpm	RHR Heat Exchanger Thermal Relief	500 psig
F12-F036	75 psig/1750 gpm	RHR Heat Exchanger Condensate Relief	125 psig

* RHR-RV-95A,B are not currently shown on Figures 5.4-13a and 5.4-13b, but are shown on Figure 3.2-6, Zones E,H and E,13.

** RHR-RV-1A,B are shown on Figures 5.4-13a and 5.4-13b (thermal relief valve on heat exchangers RHR-HX-1A,B) but are not designated by tag number.

Q. 211.077
(6.3)

Since the ECCS contains both manually operated and motor-operated valves, there is a possibility that manual valves might be left in the wrong position and that this condition will remain undetected when an accident occurs. Accordingly, provide a list of the locations and types of all manually operated valves in the safety-related systems of the WNP-2 facility. For each of these valves, provide a discussion of your procedures to minimize the possibility of an occurrence as described above. We require that you provide indication in the control room for all critical ECCS valves, either manually or motor-operated.

Response:

The following table provides a list of the location, type, size and special features of all manually operated valves (excluding test, root, vent, drain and instrument block valves) in the safety related ECCS systems of the WNP-2 facility. Test, root, vent and drain valves are excluded from the list since such improperly positioned valves will initiate a high Reactor Building sump level alarm or low pump discharege pressure alarm and cannot remain undetected. Instrument block valves are checked on a frequency established by instrument calibration requirements.

As can be seen from the list, precautions have been taken to minimize the possibility that manual valves may be left in the wrong position. Most of the valves, including all the valves in the main process flowpath, are equipped with a padlock and chain to help ensure administrative control over their being maintained in the appropriate position. In addition, all motor operated valves, as well as critical manual valves (i.e., the maintenance valves in the ECCS injection lines) are provided with limit switches to provide position indication in the control room. Manual valves are considered critical if they are in the main process flowpath and cannot be verified to be in the correct position either by visual inspection during normal plant operation or by monthly ECCS pump surveillance testing. Please refer to Figure 3.2-6, Residual Heat Removal System, and Figure 3.2-7, High Pressure Core Spray Systems, for the relative location of the valves listed.

NOTES:

1. A critical ECCS manual valve which is not accessible during normal plant operation and for which no verification is provided during monthly RHR pump surveillance testing that the valve is open.

2. The position of this valve does not effect the ability of the Low Pressure Core Spray (LPCS) to perform its safety function.

3. Closure of this valve will initiate the LPCS pump discharge line low pressure alarm in the Control Room.

4. Closure of this valve will initiate the High Pressure Core Spray (HPCS) pump discharge line low pressure alarm in the Control Room.

5. The position of this valve does not effect the ability of the HPCS to perform its safety function.

6. Closure of this valve will initiate the Residual Heat Removal (RHR) pump discharge line low pressure alarm in the Control Room.

7. The position of this valve does not effect the ability of the RHR system to perform its safety function.

VALVE NO.	QTY.	SIZE	TYPE	SPECIAL FEATURE	LOCATION	NOTES
RHR-V-171	1	1-1/2	Gate	LO	Drain Pot outlet	
RHR-V-172, A, B	2	18	Gate	LO	RHR Test Line	
RHR-V-173, A, B	2	2	Gate		RHR Heat Exchange Vent	7
RHR-V-174	1	18	Gate	LO	RHR Test Line	
LPCS-V-4	1	3	Gate		LPCS Pump discharge check valve bypass	2
LPCS-V-8	1	3	Gate	LC	LPCS drain	
LPCS-V-25	1	3	Gate	LC	Flush supply to LPCS pump discharge	
LPCS-V-32		2	Gate		Water leg pump suction isolation	3
LPCS-V-34	1	1-1/2	Stop Check		Water leg pump discharge isolation.	3
LPCS-V-51	1	12	Gate	LO/LS	LPCS line at RPV	1
LPCS-V-52	1	6	Gate	LO	LPCS pump minimum flow	
LPCS-V-60	1	12	Gate	LO	LPCS test line	
HPCS-V-3	1	3	Gate	LC	Flush supply to HPCS discharge	
HPCS-V-6	1	1-1/2	Stop Check		Water leg, pump discharge isolation	4
HPCS-V-19	1	3	Gate	LC	HPCS drain	
HPCS-V-26	1	3	Gate		HPCS pump discharge check valve bypass	5
HPCS-V-34	1	2	Gate		Water leg pump suction isolation.	4
HPCS-V-51	1	12	Gate	LO/LS	HPCS, line at RPV.	1
HPCS-V-64	1	12	Gate	LO	HPCS test line	
HPCS-V-31	1	3	Gate	LC	Flush supply to HPCS discharge	

* LO - has padlock and chain to lock valve in open position.
LC - has padlock and chain to lock valve in closed position.
LS - has integrally mounted limit switches to provide position indication in control room
BF - blind flange is attached to piping on side of valve away from ECCS process piping 1-1/2" and smaller.

VALVE NO.	QTY.	SIZE	TYPE	SPECIAL FEATURE	LOCATION	NOTES
RHR-V-7	1	3	GATE	LC	Flush supply to loop A suction	
RHR-V-18, A, B, C	3	6	Gate	LO	RHR pump minimum flow.	
RHR-V-63, A, B, C	3	3	Gate	LC	Flush supply to shut-down cooling loop.	
RHR-V-67	1	18	Gate	LC	RHR loop C crosstie.	
RHR-V-70	1	3	Gate	LC	SHR, HPCS & LPCS to drain to radwaste.	
RHR-V-71 A, B, C	3	3	Gate	LC	RHR pump suction drain.	
RHR-V-72 A, B	2	3	Gate	LC	RHR pump discharge drain.	
RHR-V-82	1	2	Gate		Water leg pump suction isolation.	6
RHR-V-85, A, B, C	3	1-1/2	Stop Check		Water leg pump discharge to RHR pump discharge line.	6
RHR-V-86	1	3	Gate	LC	Flush supply to reactor head spray.	
RHR-V-104		10	Globe	LC	Intertie to Fuel Pool Cooling system.	
RHR-V-106	1	3	Gate	LC	Flush supply to RHR Pump C suction.	
RHR-V-109	1	18	Gate	LC	RHR pump c suction from condensate system.	
RHR-V-110 A, B, C	3	18	Gate	LO	RHR pump discharge isolation.	
RHR-V-111 A, B, C	3	14	Gate	LO, LS	LPCI line at RPV	1
RHR-V-112 A, B	2	12	Gate	LO, LS	Shutdown cooling injection	
RHR-V-113	1	20	Gate	LO, LS	Shutdown cooling suction	
RHR-V-114	1	3	Gate	LC	RHR pump c discharge drain.	
RHR-V-121	1	3	Gate	LC	Radwaste sump pump intertie. to suppression pool.	
RHR-V-130 A, B	2	3	Globe	BF	Spray ring header test connection.	
RHR-V-170	1	1-1/2	Gate	LO	Drain Pot outlet	

Q. 211.078
(6.3)

Recent experience at an operating plant identified a potential for a common mode flooding of ECCS equipment rooms. The problem involved the equipment drain lines. (Refer to IE Circular No. 78-06, May 30, 1978 which is attached to this enclosure). Verify that the specific design of the WNP-2 floor and equipment drains is such that flooding in any one room or location, will not result in flooding of redundant ECCS equipment in other rooms. In responding to this item, cross-reference your response to Item 010.28.

Response:

Cross connection of ECCS pump rooms from the Reactor Building equipment drain system (Figure 9.3-5) is not possible. The equipment drain from RHR pump rooms A and B are capped. The equipment drains in the other ECCS pump rooms are directed to the floor drains.

As described in the response to Question 010.28, the Reactor Building floor drain system is served by four sumps. Each sump serves up to two rooms, with an isolation valve in the interconnecting piping. The isolation valve is not Seismic Category 1 or Class 1E, but using the acceptance criteria of Standard Review Plan 3.6.1, the floor drain system design is acceptable. Our conclusion is based on our ability to bring the reactor to cold shutdown after a pipe break outside containment and assuming single active failures. Assuming a failure of the isolation valve while flooding one room could flood the interconnected room. However, there is still adequate essential equipment not affected by the flooding to shut down the reactor.

For conditions where credit cannot be taken for non-Seismic Category 1 or non-class 1E equipment, i.e. post-LOCA, no credit is taken for the isolation valves in the cross-connecting floor drain piping. Class 1E leak detection devices in each ECCS pump room will give the operator at least 44 hours to identify and isolate passive failures in the ECCS post-LOCA before the flooding has any additional adverse effects on another ECCS pump or on the available HPSH from the suppression pool. See the response to Question 212.003 for justification of the available operator action time.

Q. 211.079
(6.3)

The discussion in 6.3.2.2.5 of the FSAR regarding the fill system you propose to prevent water hammer resulting from empty discharge lines in the residual heat removal (RHR) system and in the ECCS, is inadequate. Since there have been about fifteen damaging events due to water hammer that resulted from empty discharge lines of the core spray and RHR systems, including their associated instrumentation and alarms, to minimize water hammer. Accordingly, respond to the following matters:

a. Provide a detailed description of the fill system, including the associated instrumentation and alarms, with appropriate references to process and instrumentation drawings (P&ID's.)

b. Level transmitters apparently are not used to detect trapped air bubbles upstream of injection valves. A pressure level read downstream of a pump discharge check valve, which is greater than the gravity head corresponding to the highest point in the system, does not necessarily indicate the absence of trapped air pockets. Accordingly, indicate what provisions you have made to avoid trapping of air pockets in the lines. In your response, include a discussion of the effect of leaking valves in bypass test lines.

c. If required maintenance on a particular loop (e.g., the RHR system) necessitates draining of this loop, indicate how the fill system protects the other loop and systems; e.g., the containment spray (CS) system.

d. Indicate the surveillance testing which will be required to demonstrate that the fill system instrumentation is capable of performing its function.

e. Indicate how surveillance tests will be made to determine if the discharge lines for the RHR and CS systems are full as will be required in the WNP-2 Technical Specifications.

f. Assuming the jockey pump system does not maintain full lines, water hammer could occur during surveillance tests of the RHR and CS pumps. If damage occurred due to water hammer, the event would be reported in a licensing event report (LER). However, if special fill and vent procedures were used prior to these tests, water hammer would not occur and any inadequacies of the jockey pump system might not be evident. Accordingly, discuss: (1) your procedures for surveillance tests involving startup of RHR and CS pumps; and (2) your reporting procedures if special filling and venting procedures are used and indicate partially empty lines.

Response:

a. Each of the three ECCS divisions and the RCIC system has a separate water leg pump system powered from essential power of the same division and remote manually operable from the control room. The four water leg pump systems are shown on the following drawings:

RHR loops B & C, water leg pump RHR-L-3 (Division 2)	3.2-6
RHR Loop A and LPCS, water leg pump LPCS-P-2 (Division 1)	3.2-7
HPCS, water leg pump HPCS-P-3 (Division 3)	3.2-7
RCIC, water leg pump RCIC-P-3 (Division 1)	3.2-8

Each water leg pump motor is provided with indicating lights in the main control room to allow the operators to monitor that the motor is energized. In addition, each ECCS loop has a low pressure alarm in the control room which will alart the operator that the loop is not pressurized. These alarms are:

E12-N022A	RHR Loop A	80 psig	3.2-6
E12-N022B	RHR loop B	80 psig	3.2-6
E12-N022C	RHR loop C	80 psig	3.2-6
E21-N005	LPCS	40 psig	3.2-7
E22-N013	HPCS	50 psig	3.2-7
E51-N034	RCIC	60 psig	3.2-8

b. The water leg pumps maintain the ECCS loops pressurized. Any leakage, except as noted below, is out of the loops and is made up by the water leg pumps. Leakage across the valves on the injection lines is from the reactor pressure vessel into the ECCS loop; however, this leakage consists of water.

Gases in the ECCS loops are expected as a result of corrosion and temperature changes. The surveillance testing discussed below in d, e, and f will ensure that no significant gas accumulation occurs.

c. Division 1 and 2 water leg pump systems each maintain two ECCS loops filled. (See part a. above). They take a suction on the LPCS pump suction and RHR loop C pump suction, respectively. Maintenance on the LPCS or RHR loop C can disable the respective water leg pump system; however, no more than one ECCS division is affected.

Maintenance on RHR Loop A or B does not disable the water leg system since these loops can be isolated from their respective water leg pump system by a stop check valve. Thus, the other loop is not affected.

d. Every 31 days as part of the surveillance testing program, each of the "keepfilled" pressure instruments will be tested to verify that each alarms at its low pressure set points (see part "a" for list of alarms and set points). Every 18 months, the "keepfilled" pressure instrumentation will be recalibrated.

e. Surveillance testing verifying full RHR, HPCS and LPCS pump discharge lines will be performed every 31 days by manually opening the high point vents in each system to verify there is no trapped air in the system.

f. Prior to startup of the HPCS, LPCS and RHR pumps during surveillance testing, the pump discharge lines are verified as being full be venting the systems high point vents. If the discharge lines are found to contain significant amounts of air or gases the system will be refilled and the as-found condition reported per technical specification surveillance test non-conformance procedures. If management determines that the incident is a reportable licensing event, it will be reported in accordance with Regulatory Guide 1.16. No special fill procedure is required, since the jockey pumps for the systems run continuously to maintain the discharge lines full. It should be noted that the design of the fill system on WNP-2 meets the same criteria as was documented as acceptable in the Zimmer Safety Evaluation Report (NUREG-0528, P. 7-9, 10).

Q. 211.080
(6.3)

It is our position that the ECCS should be designed to provide sufficient capability to cool the reactor in the event of any single active or passive failure in the ECCS during the long-term cooling phase following a postulated accident. However, you have not presented sufficient information in the FSAR to demonstrate that you satisfy our requirement with regard to passive failures. In particular, our position is that you should provide leakage detection and appropriate alarms which would: (1) alert the reactor operator in the event of passive ECCS failures during the long-term cooling phase; and (2) allow the operator sufficient time to identify and isolate the faulted ECCS line. This design feature should satisfy the requirements of IEEE Std 279-1971, except for the single failure requirements. Accordingly, discuss the following considerations:

a. Indicate the assumed maximum leak rate in the ECCS, including a justification for this value.

b. Indicate the maximum allowable time for corrective operator action, including a justification for this time interval.

c. Demonstrate that your leak detection system will be sensitive enough to: (1) initiate, by alarm, operator action; (2) permit identification of the faulted line; and (3) permit isolation of the line prior to a leak creating undesirable consequences such as flooding of redundant equipment. Our position is that the minimum initiation time for operator action for this task is 30 minutes after the alarm.

d. Demonstrate that your leak detection system can identify the faulted ECCS train and that a leak would be isolable.

You should determine the effects on the ECCS of passive failures of such components as pump seals, valve seals, and measuring devices. Your analysis should address the potential for flooding caused by the ECCS and the potential for ECCS inoperability which could result from a depletion of the water inventory in the suppression pool Your analysis should include consideration of (1) the flow paths of the radioactive fluid through floor drains sump pump discharge piping, and the auxiliary building; (2) the operation of the

auxiliary systems that would receive the radioactive fluids; and (3) the ability of the leakage detection system to detect a passive failure. Examine the auxiliary system piping in the vicinity of ECCS equipment and address the potential for flooding from nonsafety-graade piping. (Refer to Attachment 1 to this enclsoure).

Response:

See response to Question 212.003, Amendment 5, concerning Reactor Systems Branch Technical Position, Leak Detection Requirements for ECCS Passive Failures. It addresses the potential for flooding caused by the ECCS and the potential for ECCS inoperability which could result from the depletion of the water inventory in the suppression pool. An examination of the auxiliary system piping in the vicinity of ECCS equipment and the potential for flooding from nonsafety grade piping is addressed in the response to Questions 010.28 and 211.78.

Q. 211.081
(6.3)

During the long-term cooling phase following a small break LOCA, the reactor operator must control the primary system pressure to preclude overpressurization of the RPV after it has been cooled down. Accordingly, provide the following information:

a. Describe the instructions which the operator will follow while performing long-term cooling of the plant.

b. Indicate the time frame in which the operator will perform the required actions, including justification for the timing of the operator's actions.

c. List the instrumentation and components needed to perform this action and confirm that these components meet safety grade standards.

d. Discuss the pertinent safety concerns during this cool-down period and indicate the design margins available for each concern.

e. Provide plots of the temperature, pressure, and the water inventory in the reactor coolant system (RCS), showing the important occurrences during this cool-down period.

In your response, account for the following events: (1) a loss of offsite power; (2) an operator error; or (3) a single failure.

Response:

During long-term cooling following a small LOCA, there are no operator actions required to control system pressure to preclude overpressurizing the pressure vessel after it has been cooled off. The system is always protected by relief valves which are more than adequate to handle decay heat energy generation. If the small LOCA caused reactor vessel water level to drop to level 3 or resulted in sufficient drywell pressurization, then the plant would automatically scram. If water level drops to level 2, then HPCS would come on automatically and re-establish water level for the

postulated small LOCA, and would automatically control water level to provide adequate core cooling. If the small LOCA had caused sufficiently high drywell pressure and the water level decreased to level 1, then ADS would automatically come on to depressurize the vessel and all remaining ECCS systems would automatically initiate to re-establish water level. The ADS valves stay open once actuated, and are designed to stay open for at least 100 days thereby precluding any significant repressurizing of the reactor vessel.

In response to particular portions of this question, we offer the following:

a. There are no operator actions required following a small LOCA to preclude overpressurizing the pressure vessel after it has been cooled off. Operator actions to establish long-term cooling are discussed in 6.2.2.2 and 6.2.2.3.

b. No operator actions are required.

c. No operator actions are required.

d. Limiting safety concerns are addressed in 6.2, Containment Barrier Integrity; 6.3, Peak Cladding Temperature; and Chapter 15, Radiological Releases. The event is not a limiting event for designing to assure the health and safety of the public.

e. System characteristics for the more severe design basis events are shown in 6.2 and 6.3.

The above discussion accounts for:

(1) Loss of Offsite Power

(2) Operator Error or Single Failure

Q. 211.082
(6.3)

Demonstrate that for all sizes of breaks in a recirculation loop or in ECCS lines which would thereby require actuation of the ECCS, the reactor core is sufficiently covered with water so that diversion of the LPCI system to wetwell spray after 10 minutes is acceptable and that the ECCS systems are in compliance with the requirements of Criterion 35 of the General Design Criterion (GDC) and Section 50.46 of 10 CFR Part 50. In your response, indicate what consideration you have given to the full spectrum of potential single failures and to potential break locations. Confirm that no operator action affecting the performance of the ECCS is required prior to 20 minutes after the initiation of the accident.

In particular, discuss the effects of the following matters on cooling of the reactor core and provide information to show that the requirements of GDC 35 and Section 50.46 of 10 CFR Part 50 are not violated.

a. Provide assurance that the system which diverts the LPCI flow meets the single failure criterion so that diversion of the LPCI system less than 10 minutes after a postulated accident need not be considered.

b. Provide justification for the conclusion that a break in a ECCS line is the most limiting break location when evaluating the effects of a postulated LOCA followed by diversion of the LPCI flow.

c. Provide a sensitivity study of the PCT as a function of break size for small break LOCA's, assuming LPCI diversion will be initiated 10 minutes after the start of the accident. Perform this study for postulated breaks in the ECCS and recirculation lines. For the most limiting break, provide the following figures: (1) the water level inside the shroud as a function of time following the postulated LOCA; (2) the reactor vessel pressure versus time; (3) the convective heat transfer coefficient versus time; (4) the peak clad temperature versus time; and (5) the ECCS flow rate versus time.

d. Provide assurance that LPCI diversion after 10 minutes will have less severe consequences than diversion at 10 minutes, considering the appropriate break sizes for diversion at times greater than 10 minutes after the accident.

e. Provide a discussion which contrasts the need for LPCI diversion for the limiting break size with the need for abundant core cooling required by GDC 35. For example, this discussion could consider the likelihood of LPCI diversion for the limiting break size.

Response:

An analysis which shows acceptable results following diversion of LPCI 10 minutes after a break is provided in the Zimmer docket in response to their Question 212.072. The Zimmer analysis is typical of any BWR/5, as they have the same complement of ECCS systems and is therefore applicable to WNP-2.

No operator action affecting the performance of the ECCS is required prior to 20 minutes after initiation of the accident. We have evaluated the consequences of no operator action for 20 minutes in our response to Question 211.059 and conclude that the requirements of GDC 35 and 10 CFR 50.46 are met. The diversion of LPCI for wetwell sprays is addressed in the response to Question 031.070. Diversion is not anticipated to be required at all, and certainly not in the first 20 minutes. Bounding studies indicate that over 167 minutes are available for the operator to take action after a small break before drywell design pressure is exceeded, assuming bypass leakage five times that allowed per technical specification requirements. Leakage rates smaller than this do not exceed drywell design pressure.

Specific parts of this question are answered as follows:

a. This question presumes that an automatic wetwell spray system is provided. However, in our response to Question 031.070, we showed why automatic sprays are not needed for WNP-2. The Residual Heat Removal system, which provides for diversion of LPCI, is safety-related, redundant and powered from different divisions.

b. The HPCS line break/LPCS diesel-generator failure is the limiting event. Justification is provided in the Zimmer analysis.

c. The information requested on PCT is provided in Figures Q212.72-1 through Q212.72-5 of the Zimmer analysis. The information requested for the most limiting break is provided in Figures Q212.72-6 through Q212.72-10 of the Zimmer analysis.

d. The information requested is provided in the Zimmer analysis.

e. The information requested is provided in the Zimmer analysis.

Q. 211.083
(6.3)

Provide assurance that the fast closure of a recirculation flow control valve conincident with a LOCA is not expected to occur. Alternatively, provide the results of a sensitivity study which evluates the effects of a fast closure of a recirculation flow valve conincident with the design basis LOCA and the worst postulated ECCS failure.

Response:

Refer to our response to Q. 31.058 for a detailed discussion of why closure of the recirculation flow control valve will not occur.*

*Draft FSAR page change attached.

A complete system failure mode and effects analysis along with a more detailed system description are described in ~~the soon to be submitted~~ "Appendix H" of the FSAR. ~~(Scheduled to be submitted in the first quarter of 1979.)~~

Q. 211.084
(15.2)

Your proposed reclassification of the transients resulting from a generator trip and a turbine trip without bypass, from a frequent to a infrequent event in Section 15.2.2.1.2.2 of the FSAR has not been accepted by us and is still under generic review. Accordingly, reanalyze the events cited above to determine the operational limit on the minimum critical power ratio (MCPR) which would not violate the minimum safe valve of 1.06 for the MCPR. It is our position that the limiting transient be reanalyzed with the ODYN code cited in Item 211.49 of this enclosure.

Response:

See the response to Question 211.049.

Q. 211.085
(15.A)

Modify your nuclear safety operational analysis (NSOA) drawings to show the nonsafety-grade equipment for which you take credit to mitigate transients and accidents. Such equipment includes relief valves, turbine bypass valves, and a vessel level trip indicating high water in the RPV (i.e., a Level 8 trip).

Response:

Each transient and accident discussed in Chapter 15 corresponds to one protection sequence of an event in Appendix 15A. The NSOA drawings (protection sequences) are consistent with the analytical bases of 15A.3 and the measures of safety (unacceptable results) of 15A.2.7 and are primarily directed at system level response requirements.* Certain Chapter 15 events assume, following the initiating single-failure, the normal operation of some nonsafety-grade equipment functions; these instances are identifiable from the text.

Much discussion has occurred between the NRC and General Electric concerning the use of nonsafety-grade equipment in analyzing transients. Table 211.85-1 summarizes the nonsafety-grade equipment which is utilized and gives appropriate justification for taking credit for such equipment.

*Draft FSAR page changes attached.

Table 211.085-1
Identification of Nonsafety-Grade Equipment
Assumed to Function in Chapter 15 Analyses

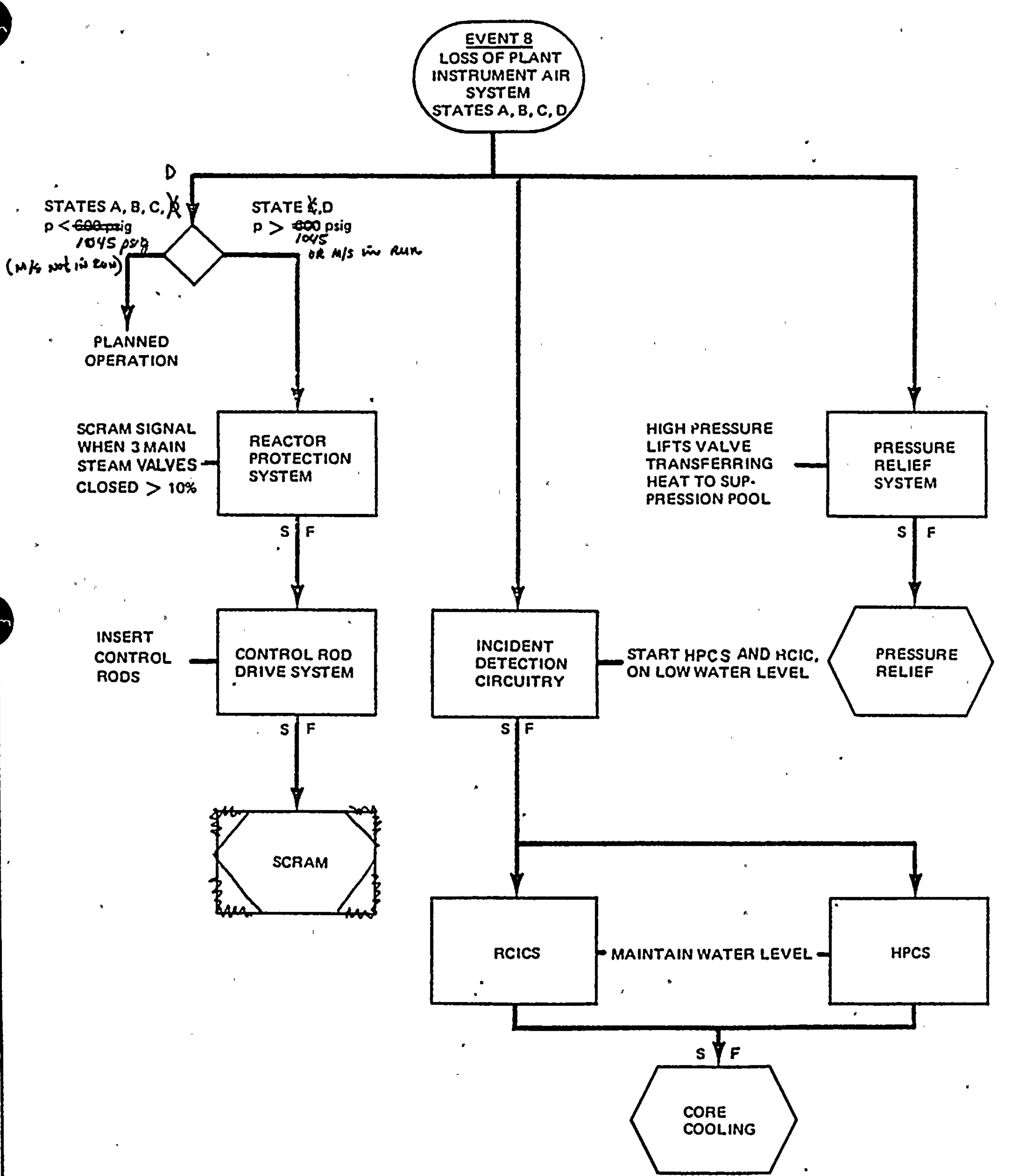
Nonsafety-Grade System/Function Utilized	Transient(s) Involved by Number	Justification for Taking Credit in the Analyses
Feedwater Control System (High Rx Water Level Trip Logic, L8)	21, 22, 23, 27, 30, 25, 31, 38, 29, 13, 12, 11, 38, 39	The L8 circuitry is 2 out of 3 logic with diverse power supplies such that a single level switch (ls) failure will not cause or prevent the trip function from occurring. The Tech. Spec. surveillance committed to by the 211.086 response will provide assurance that the trip function will operate when required. This resolution was agreed upon by the NRC (GE-NRC meeting, Nov. 20,21, 1978) and affirmed at the Zimmer ACRS hearings.
Turbine DEH System (Bypass Valve Operability	11, 12, 13, 21, 22, 23, 25, 26, 27, 28, 29, 38, 39	The DEH system is functioning continuously at power which demonstrates its operability. The Tech. Spec. surveillance committed to by the 211.086 response will provide additional assurance that the BPVs themselves are functional. This resolution was agreed upon by the NRC (GE-NRC meeting, No.v 20, 21, 1978) and affirmed at the Zimmer ACRS hearings.

Table 211.085-1
Identification of Nonsafety-Grade Equipment
Assumed to Function in Chapter 15 Analyses

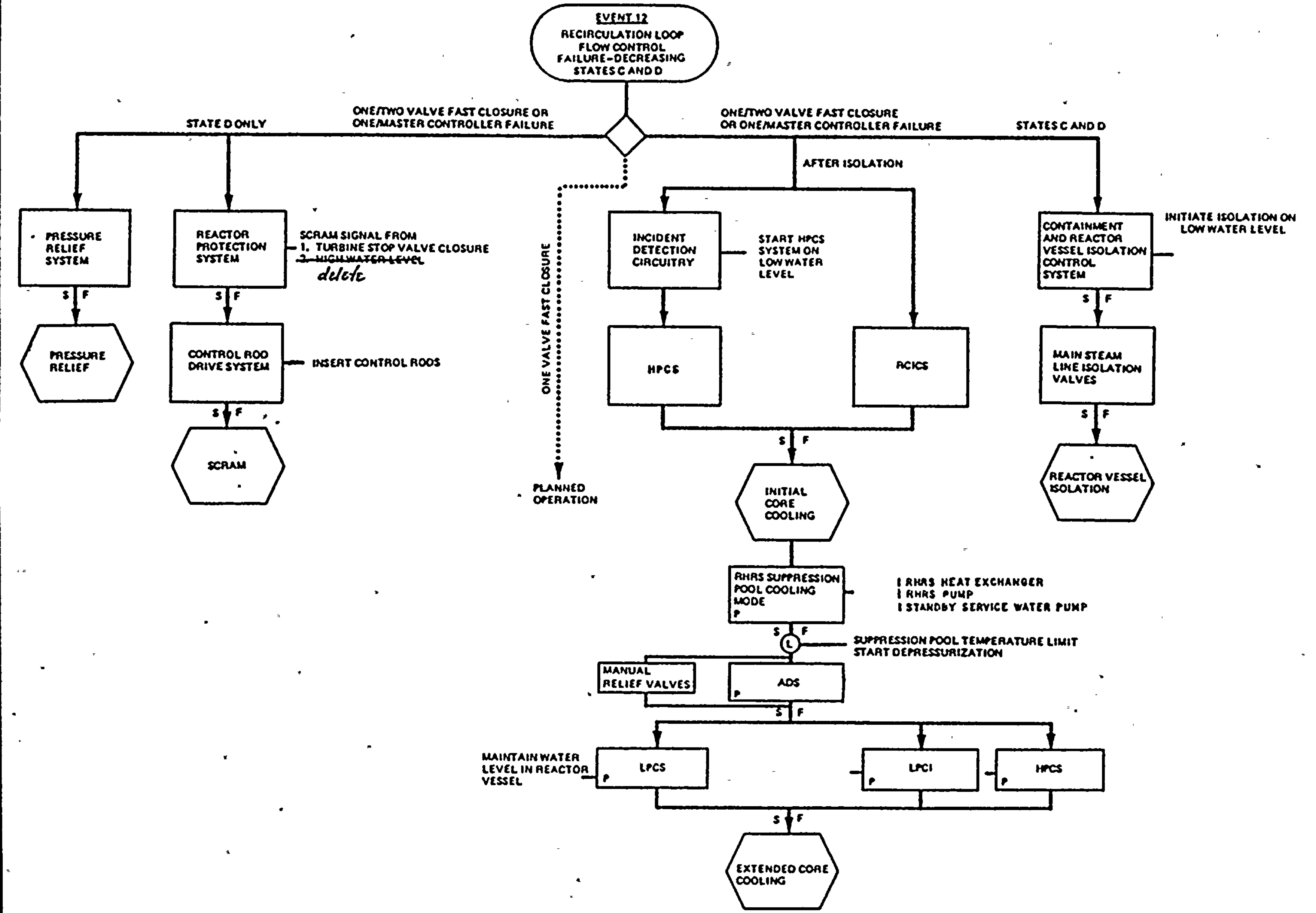
Nonsafety-Grade System/Function Utilized	Transient(s) Involved by Number	Justification for Taking Credit in the Analyses
Pressure Relief System (Power Actuated Relief Mode)	8, 22, 23, 27, 29, 30, 31, 12, 14, 26, 20, 13, 15, 20, 24, 25, 28, 38, 39, 40, 42, 43, 44, 45, 51, 52, 53	For all transients identified, failure to actuate has no impact upon Core Thermal Limits (MCPR). Peak Rx pressure would be higher. However, the vessel over-pressurization analysis is still bounding. See the response to 31.064. In addition, NRC concerns in this area include the use of protection system inputs which are non-seismic category I or are located in non-seismic category I structures (ie, the Turbine Building). Responses on the LaSalle docket to NRC questions 212.55, 212.61, 212.105, 212.115, 212-129, and 212-144 address this issue in detail and are considered applicable to WNP-2. Similarly, conclusions from responses on the Zimmer docket, questions 221.270 and 221.359 are considered applicable to WNP-2.
RCIC Initiation (Initial Core Cooling)	8, 21, 13, 14, 15, 20, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 38, 39, 40, 51, 53	The RCIC system has been upgraded by the addition of a seismic 1 water supply via auto-transfer of the pump suction from the CST to the Suppression Pool. The system has long been covered by Tech. Spec. surveillance and now is as reliable as a fully safety-grade system. This resolution was agreed upon by the NRC. (Zimmer SER, NUREG-0528, p. 7-9).

Table 211.085-1
Identification of Nonsafety-Grade Equipment
Assumed to Function in Chapter 15 Analyses

Nonsafety-Grade System/Function Utilized	Transient(s) Involved by Number	Justification for Taking Credit in the Analyses
RSCS/RWM/RBM (Prevent improper rod movement)	16, 17, 40 (implicit/passive)	The RWM/RSCS are independent systems. Below 20% power the RWM/RSCS work in tandem to prevent rod withdrawal errors. At these lower power levels the neutron monitoring system via the IRMs acts to scram the Rx and prevent fuel damage in the event of RWM/RSCS failure. Above 20% power the RBM (2 independent channels; 1 required to initiate a rod block) provides protection from improper rod motion. In addition, strict administrative controls enforce approved rod withdrawal sequences. Only unauthorized, unsupervised rod movements should challenge the RBM system to function. See the response to NRC question 31.109 for further information.
Refueling Interlocks/RPS (Prevent more than 1 rod withdrawal while in states A & B)	16	Refueling operations are a period of strictly supervised actions. Rod motion is required only to confirm proper fuel cell loading/CRD mode operation and subcriticality. The refueling interlocks in addition to administrative controls prevent more than 1 rod withdrawal. Several levels of supervision would have to be bypassed to produce a challenge to the refueling interlocks. The refueling interlock system, in addition, provides two independent channels of interlock protection designed to fail-safe philosophy. See revised secton 7.7.1.13 for more detail.



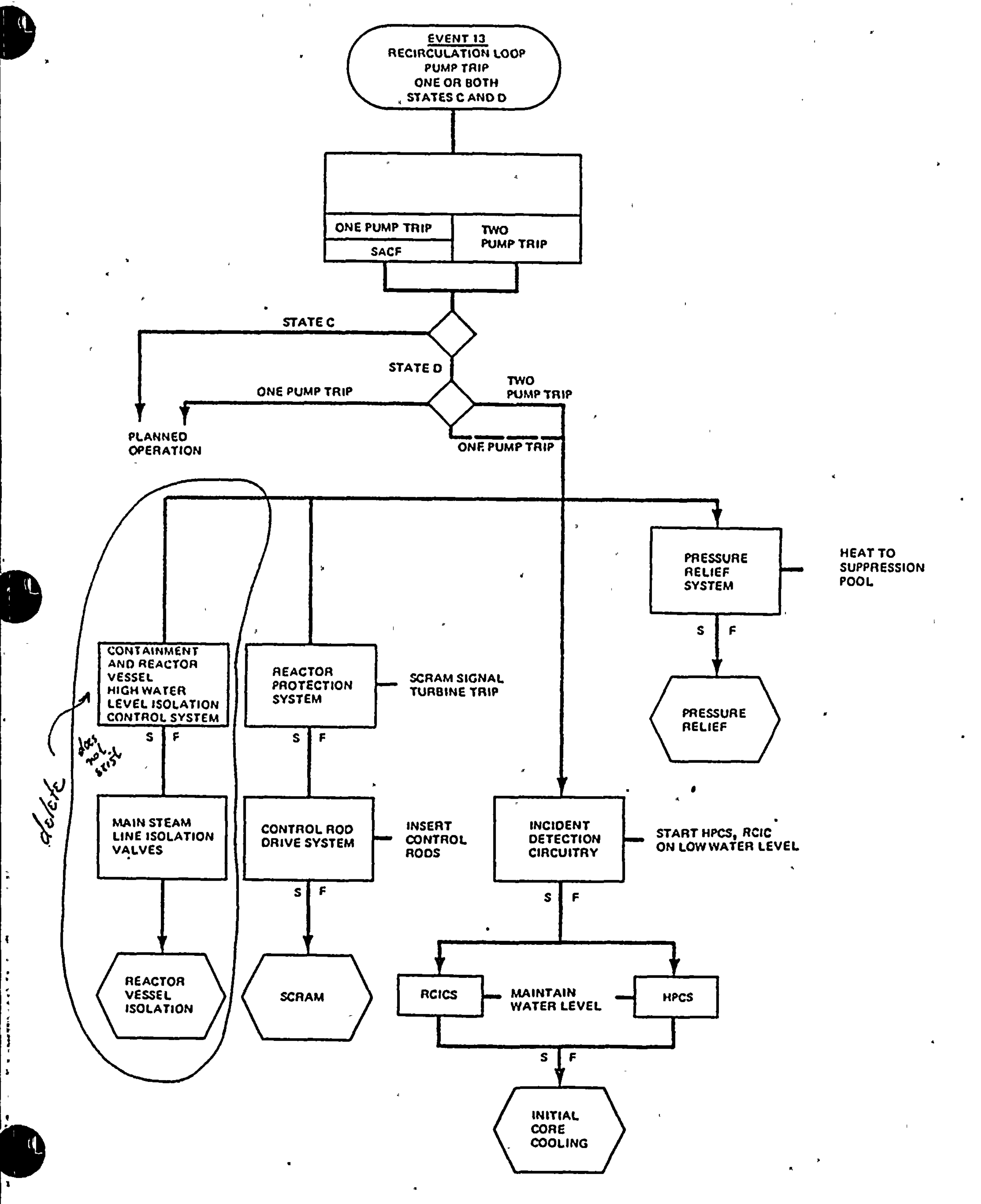
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR LOSS OF PLANT INSTRUMENT/SERVICE AIR SYSTEM	FIGURE 15.A.6-8



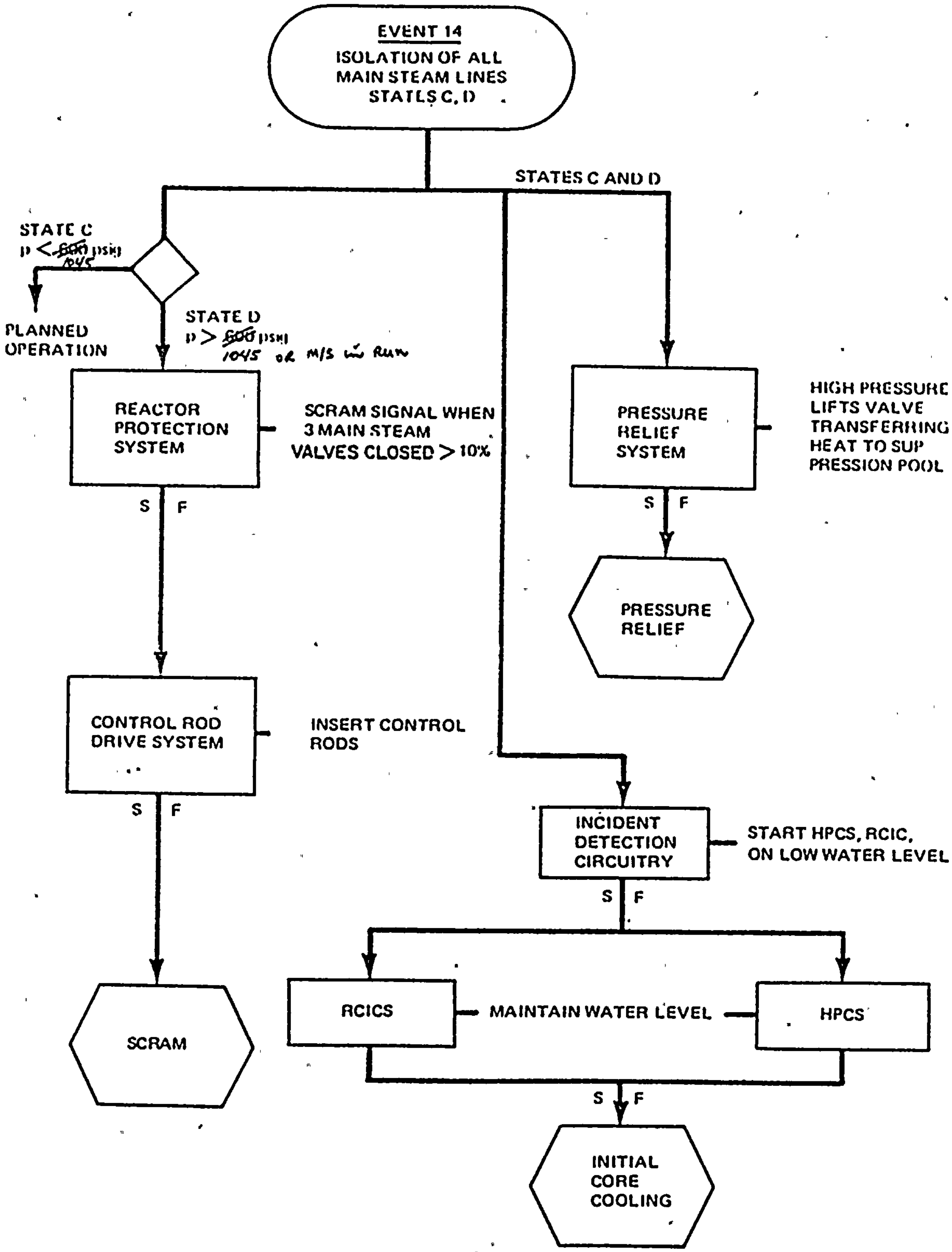
WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR RECIRCULATION LOOP FLOW CONTROL FAILURE-DECREASING

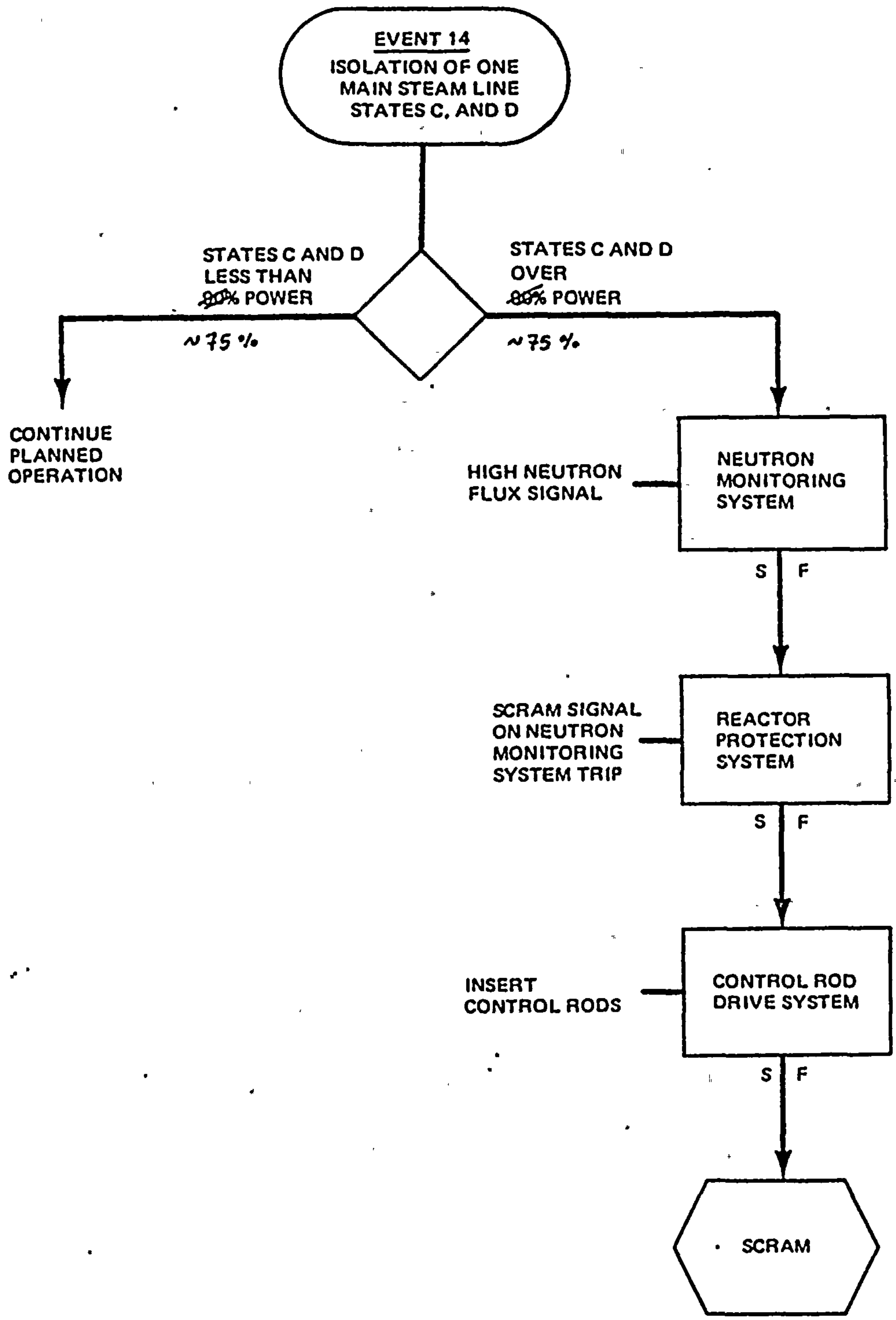
FIGURE 15.A.6-12



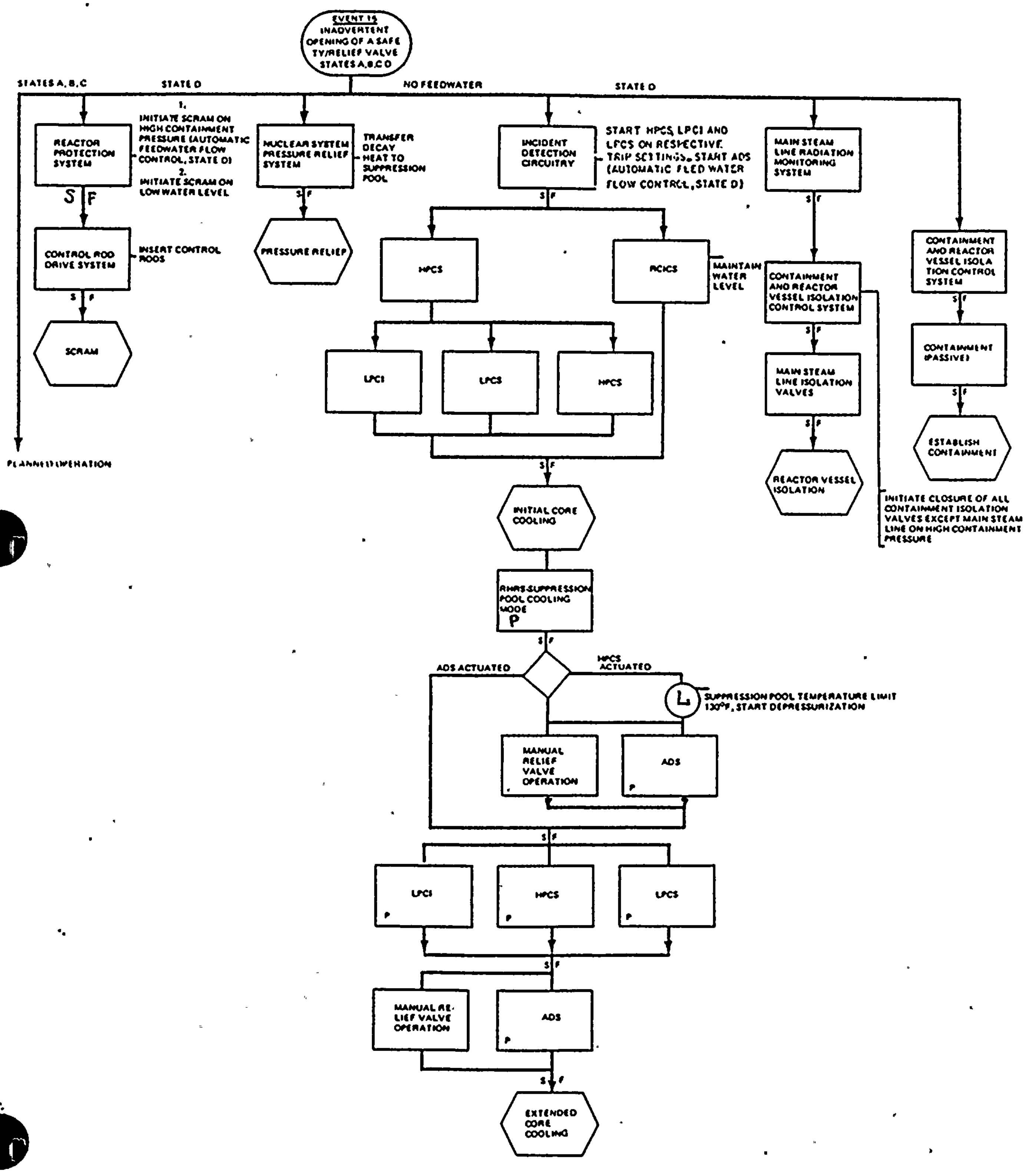
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR RECIRCULATION LOOP PUMP TRIP - ONE OR BOTH	FIGURE 15.A.6-



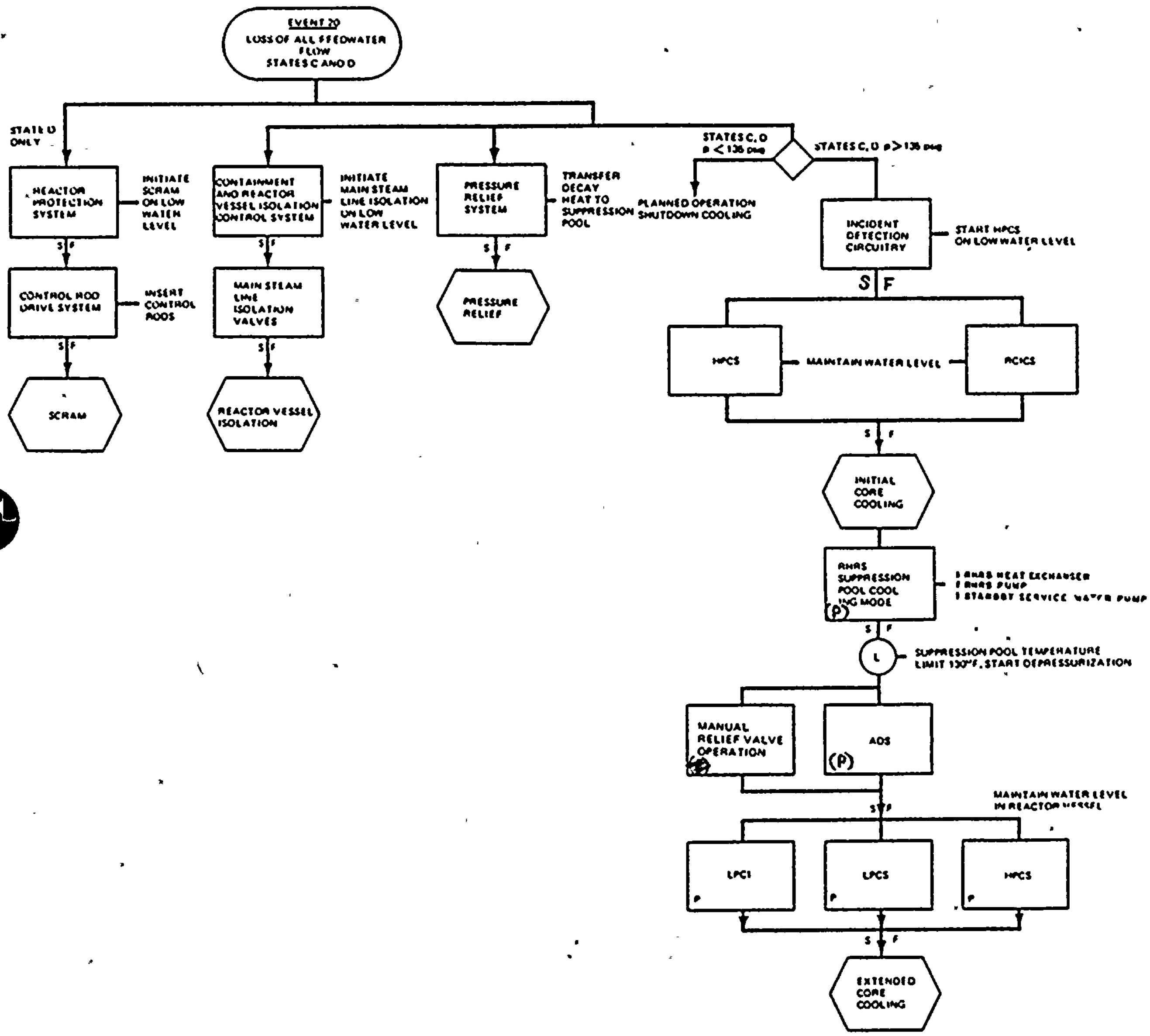
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR ISOLATION OF ALL MAIN STEAM LINES	FIGURE 15.A.6- 14a



WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR ISOLATION OF ONE MAIN STEAM LINE	FIGURE 15.A.6-14b



WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR INADVERTENT OPENING OF A RELIEF OR SAFETY VALVE	FIGURE 15.A.6-15

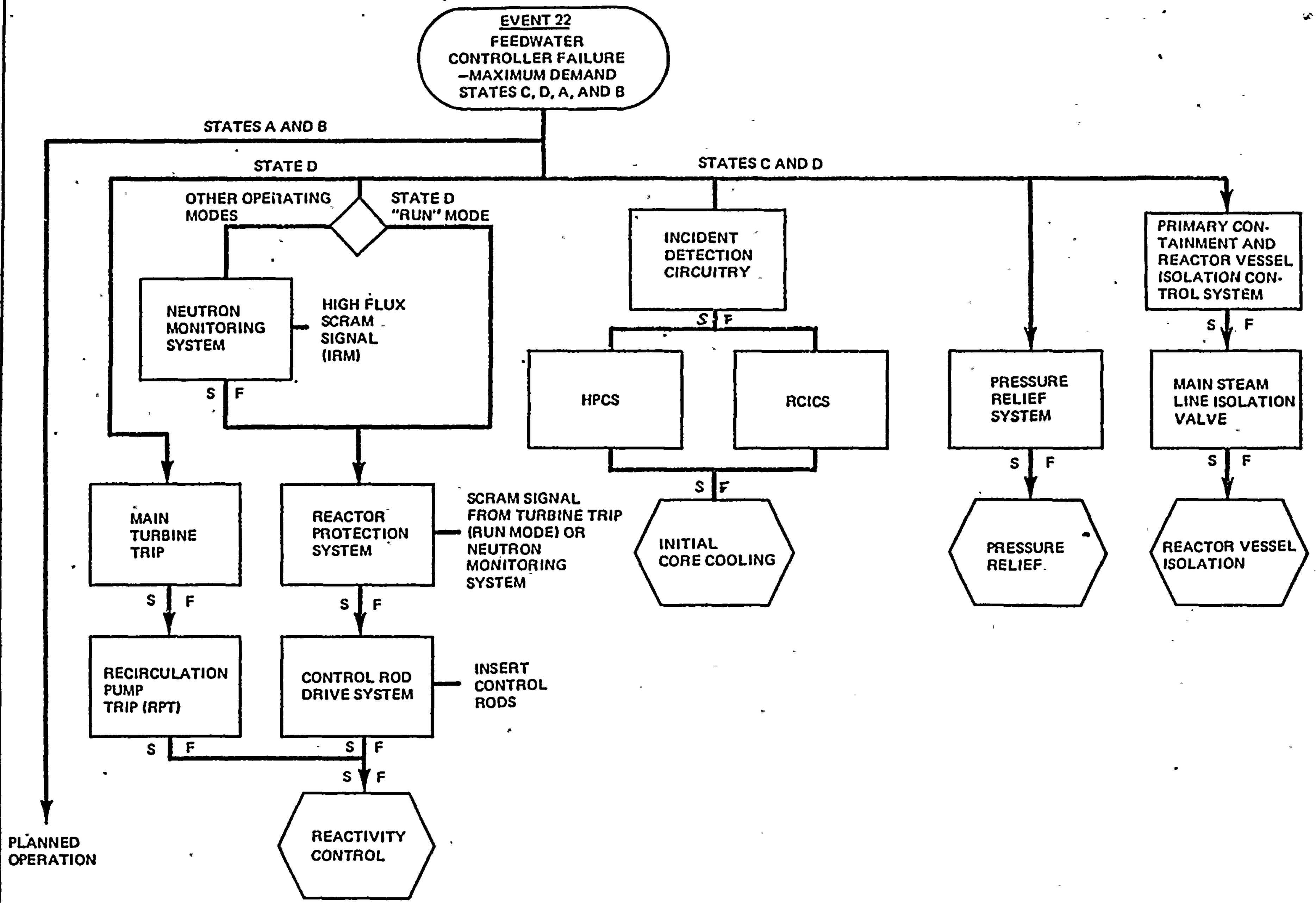


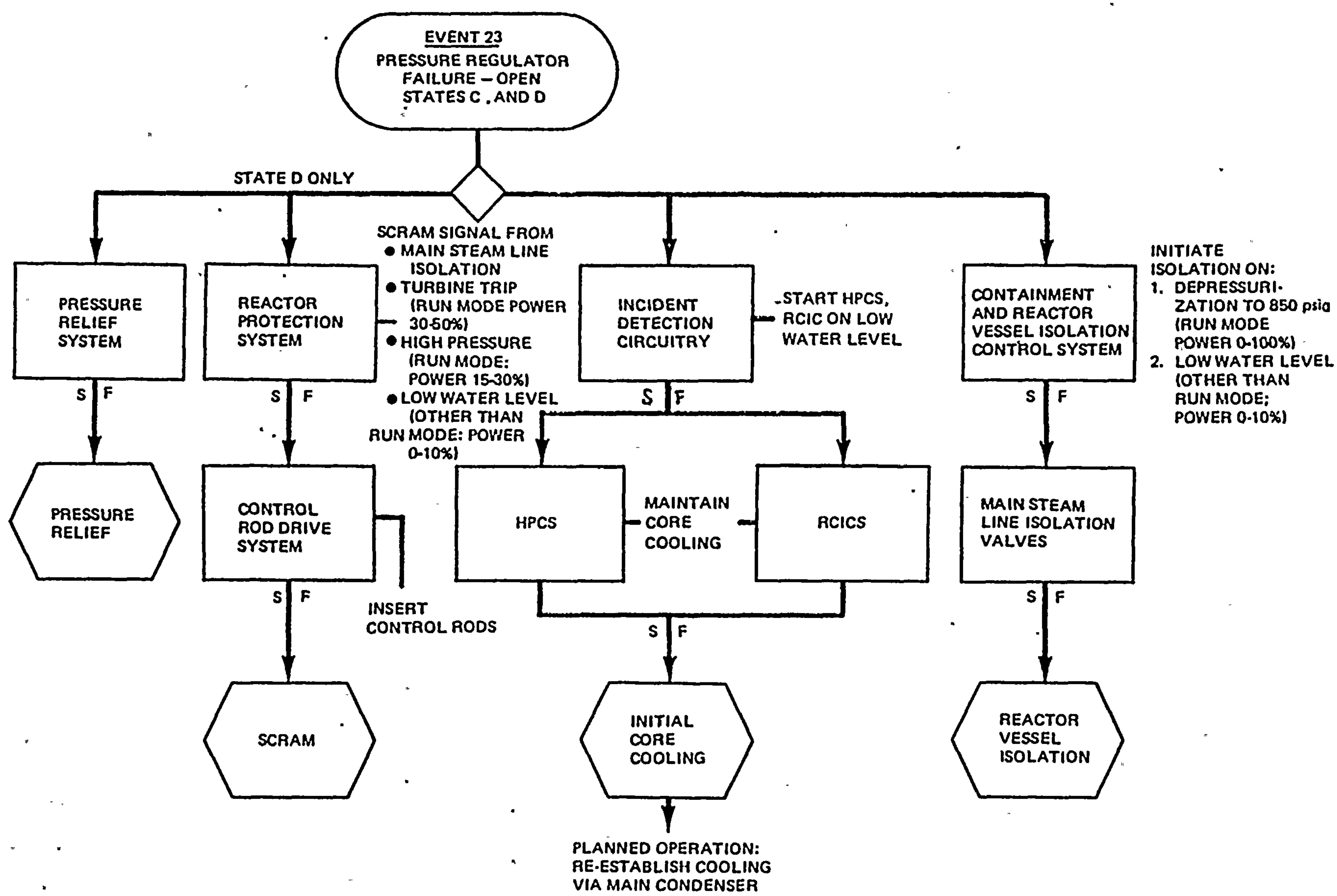
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR LOSS OF FEEDWATER FLOW	FIGURE 15.A.6-20

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR FEEDWATER CONTROLLER FAILURE - MAXIMUM DEMAND

FIGURE 15.A.6-22

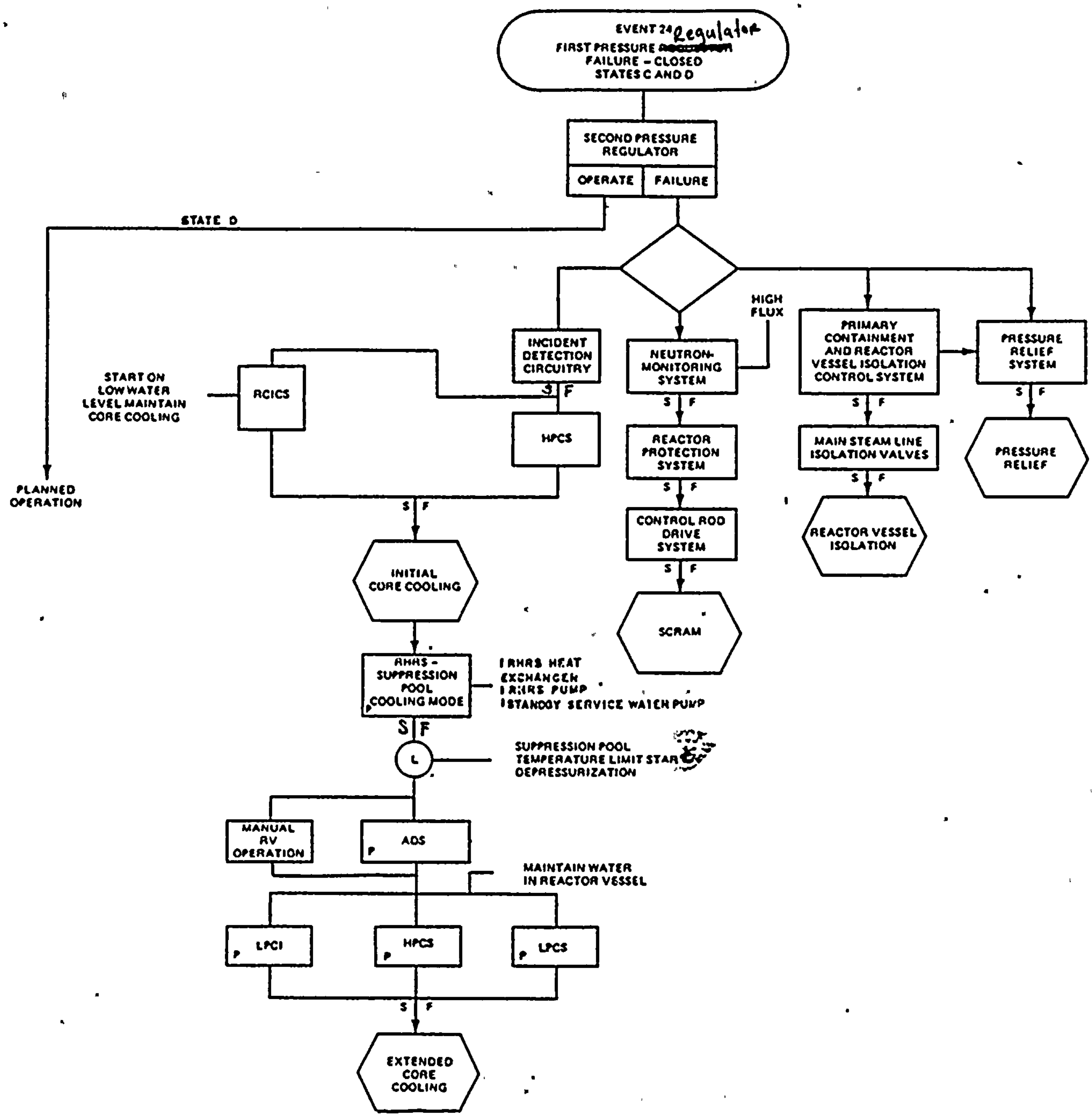




WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR PRESSURE REGULATOR FAILURE - OPEN

FIGURE 15.A.6-23

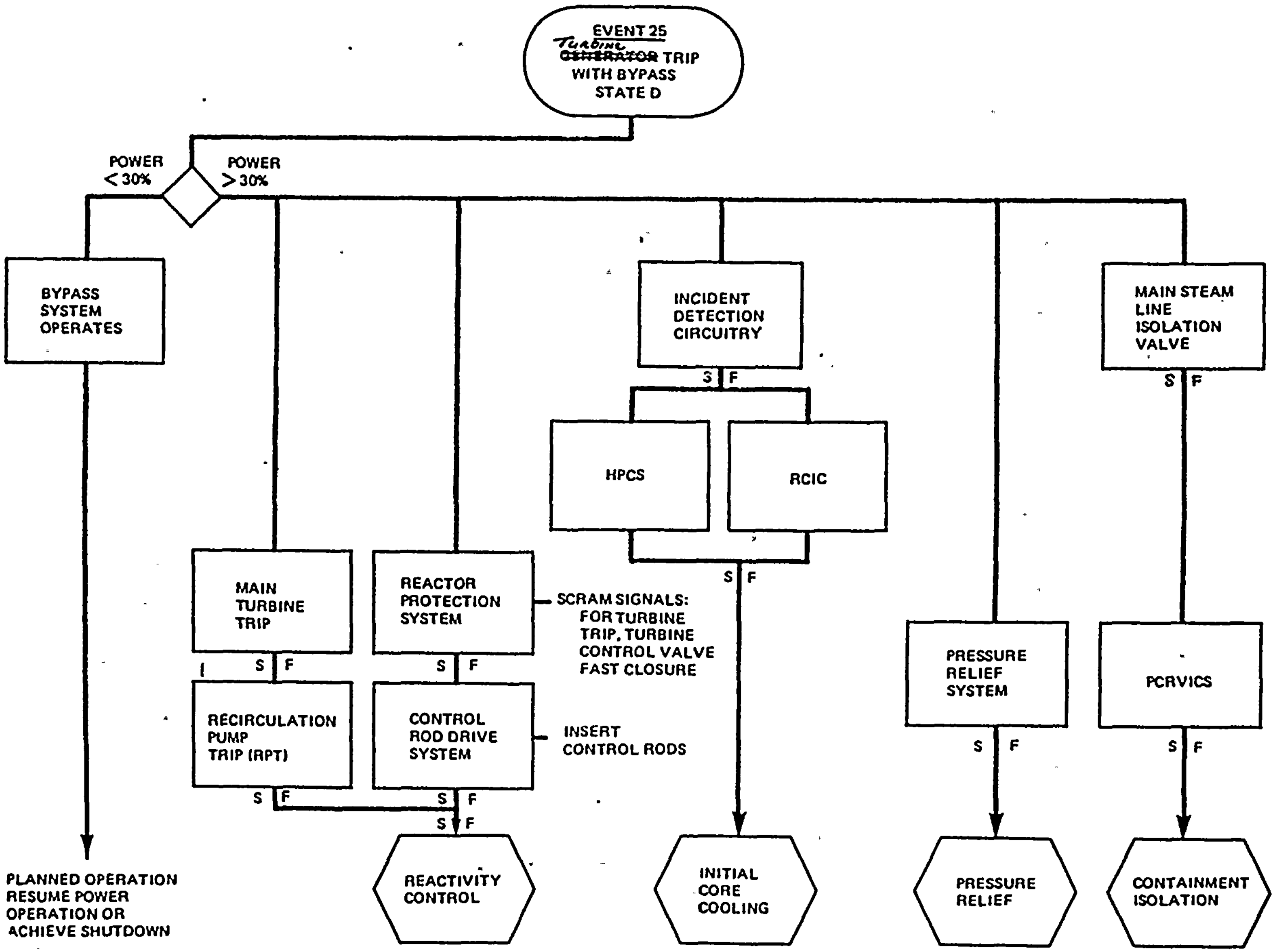


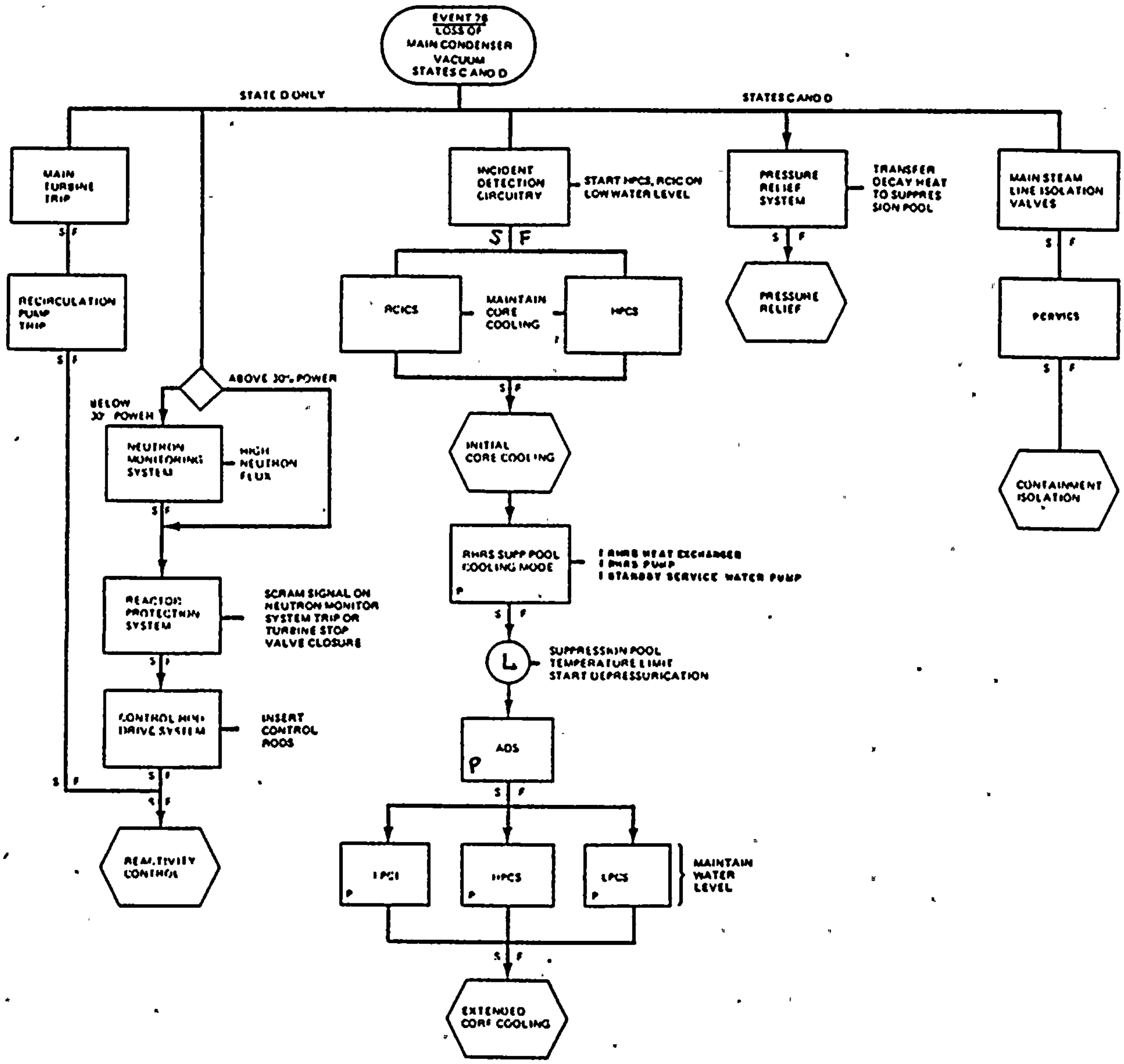
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR PRESSURE REGULATOR FAILURE-CLOSED	FIGURE 15.A.6-24

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

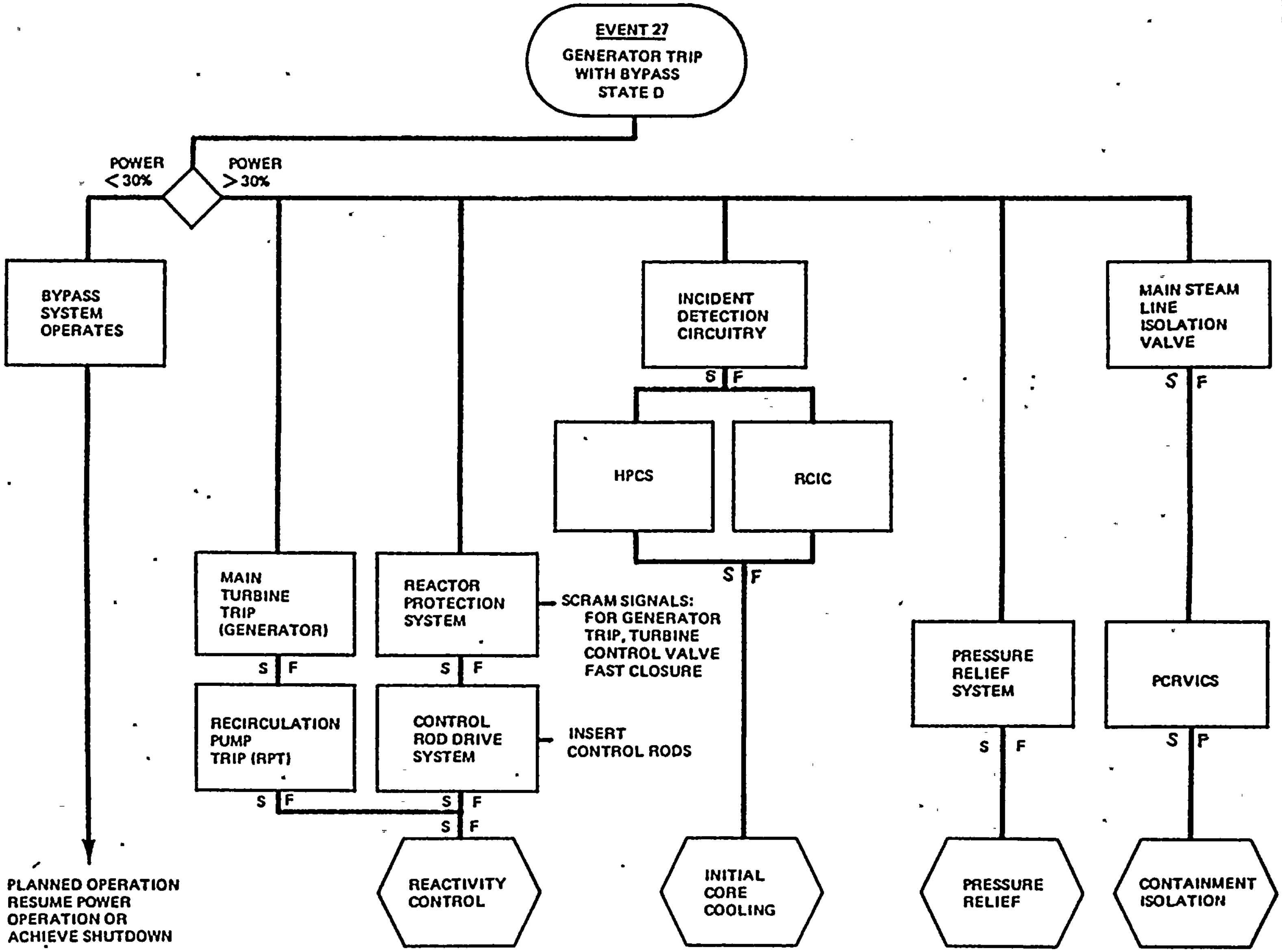
PROTECTION SEQUENCE FOR MAIN TURBINE TRIP WITH BYPASS

FIGURE 15.A.6-25





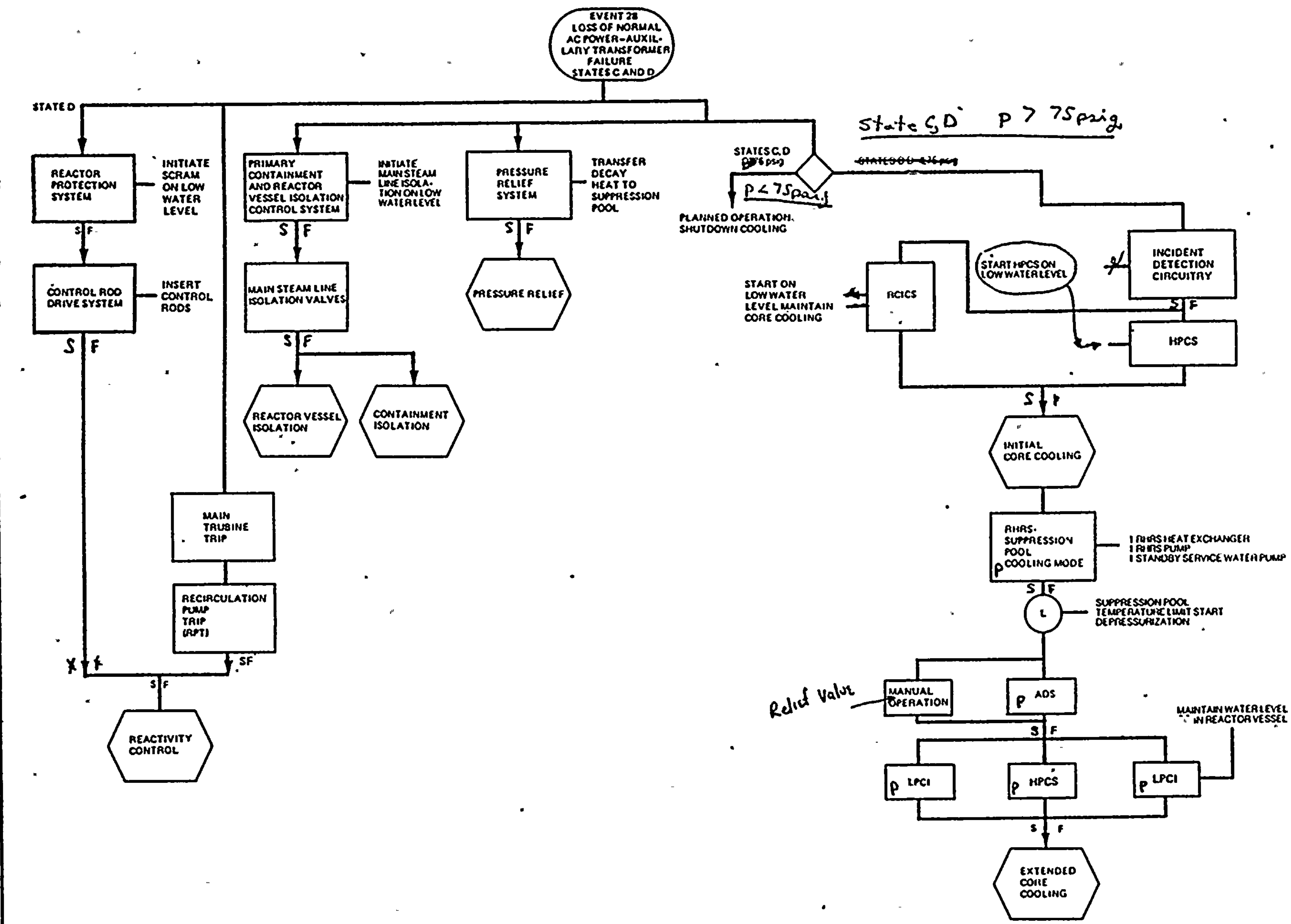
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR LOSS OF MAIN CONDENSER VACUUM	FIGURE 15.A.6-26



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR MAIN GENERATOR TRIP WITH BYPASS

FIGURE 15.A.6-27



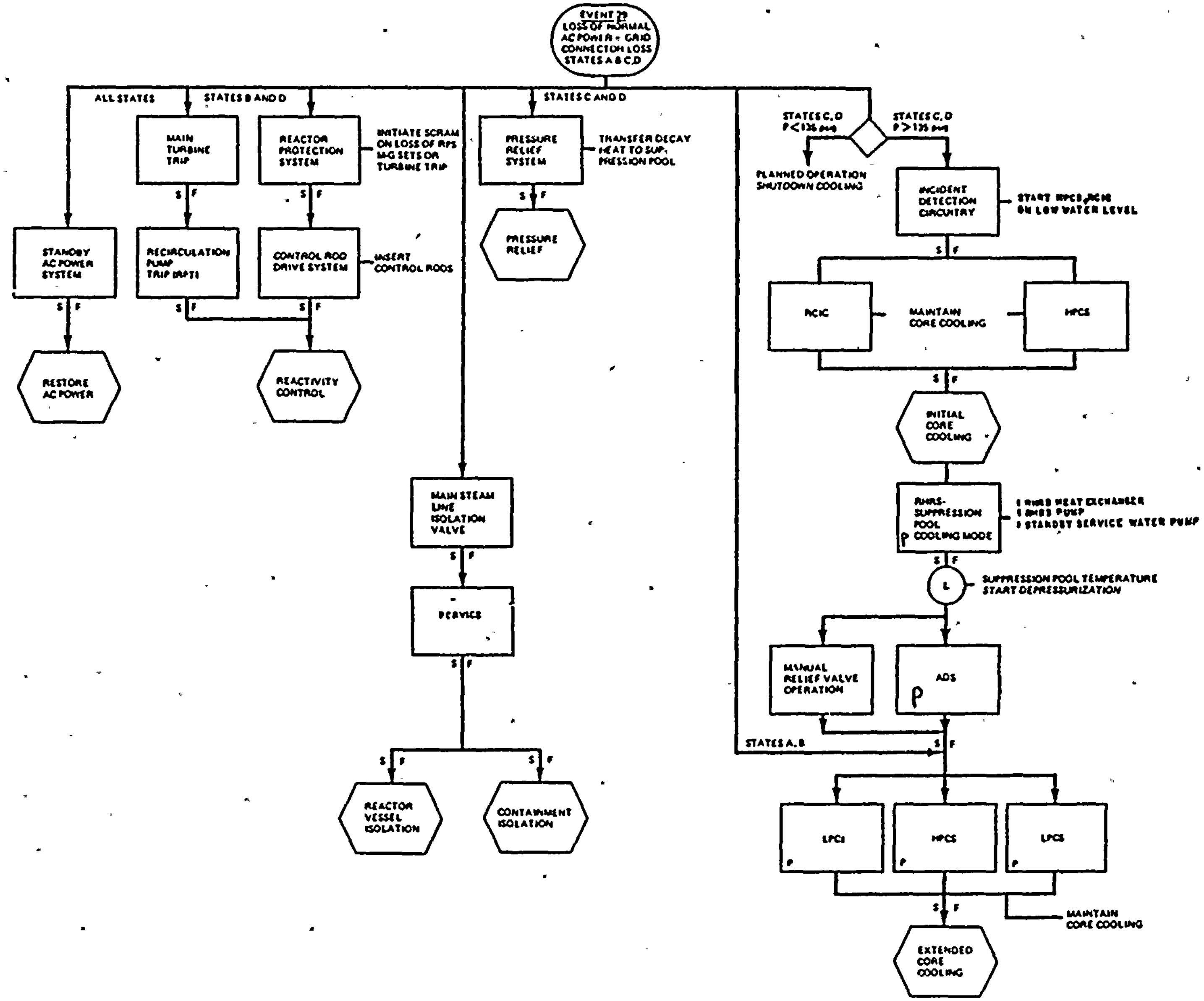
AMENDMENT NO. 1
July 1978

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR LOSS OF NORMAL AC POWER-AUXILIARY TRANSFORMER FAILURE

FIGURE 15.A.6-28

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2



PROTECTION SEQUENCE FOR LOSS OF NORMAL AC POWER-GRID CONNECTION LOSS

FIGURE 15.A.6-29

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE MAIN TURBINE TRIP - WITHOUT BYPASS

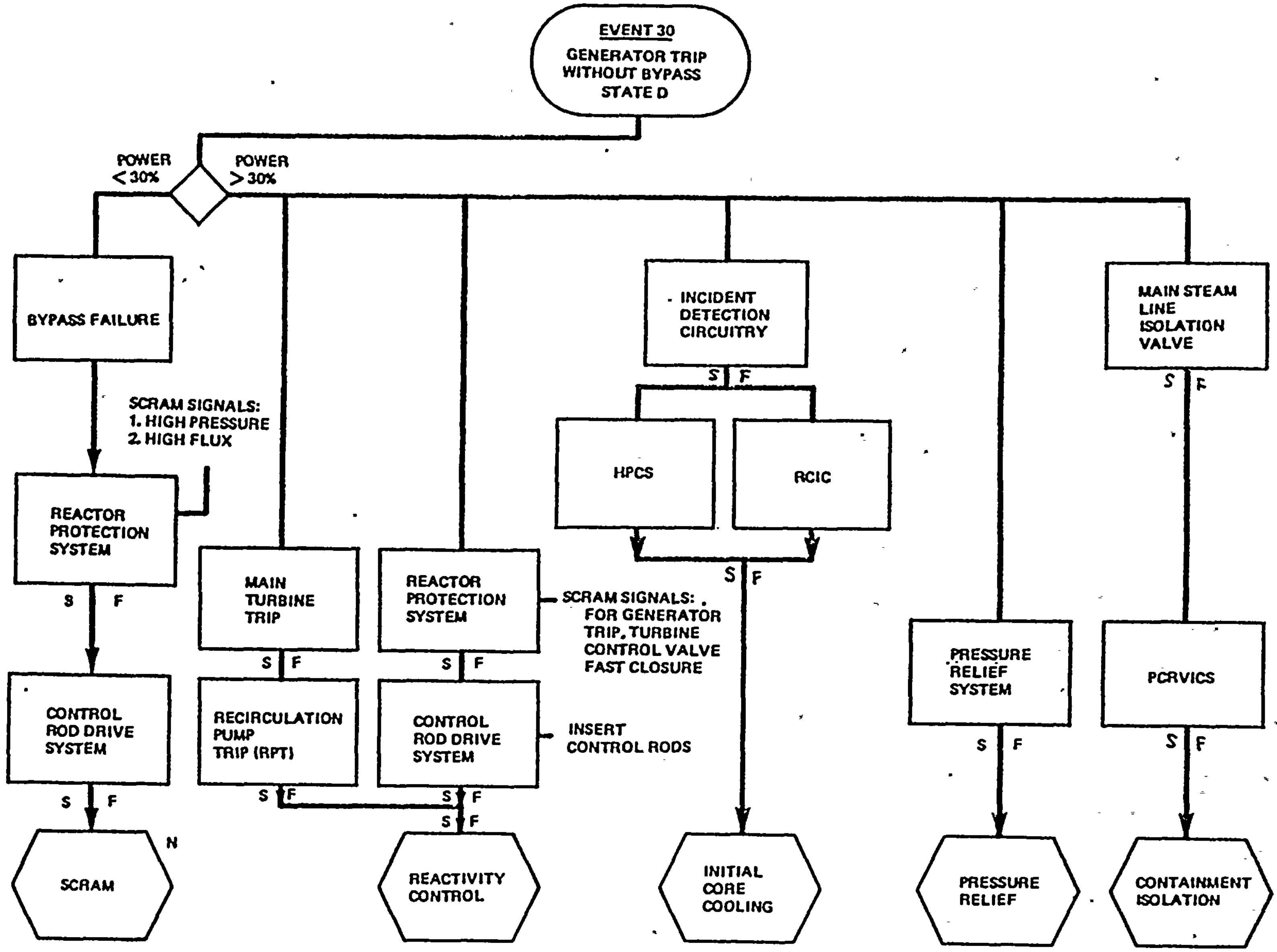
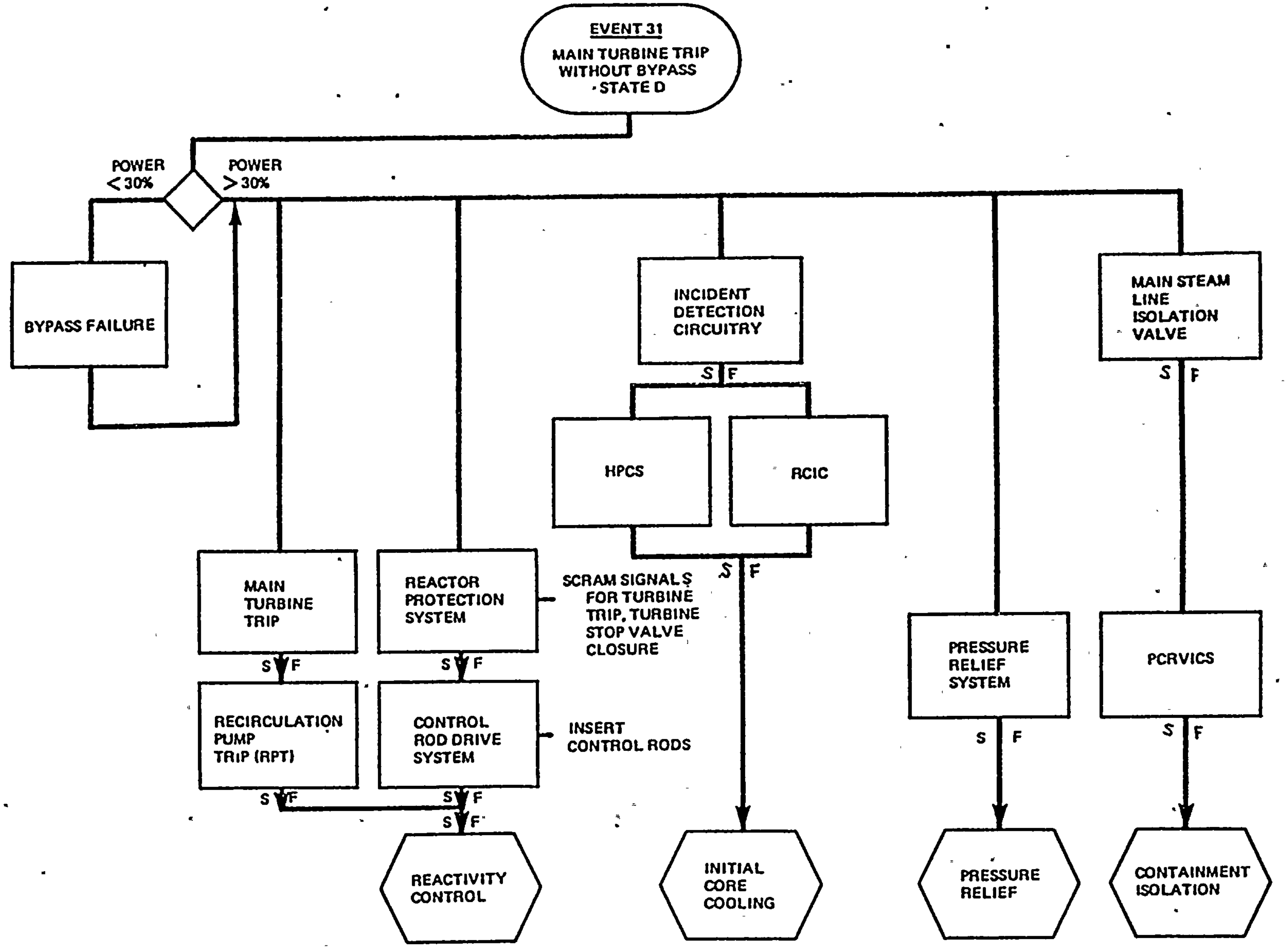


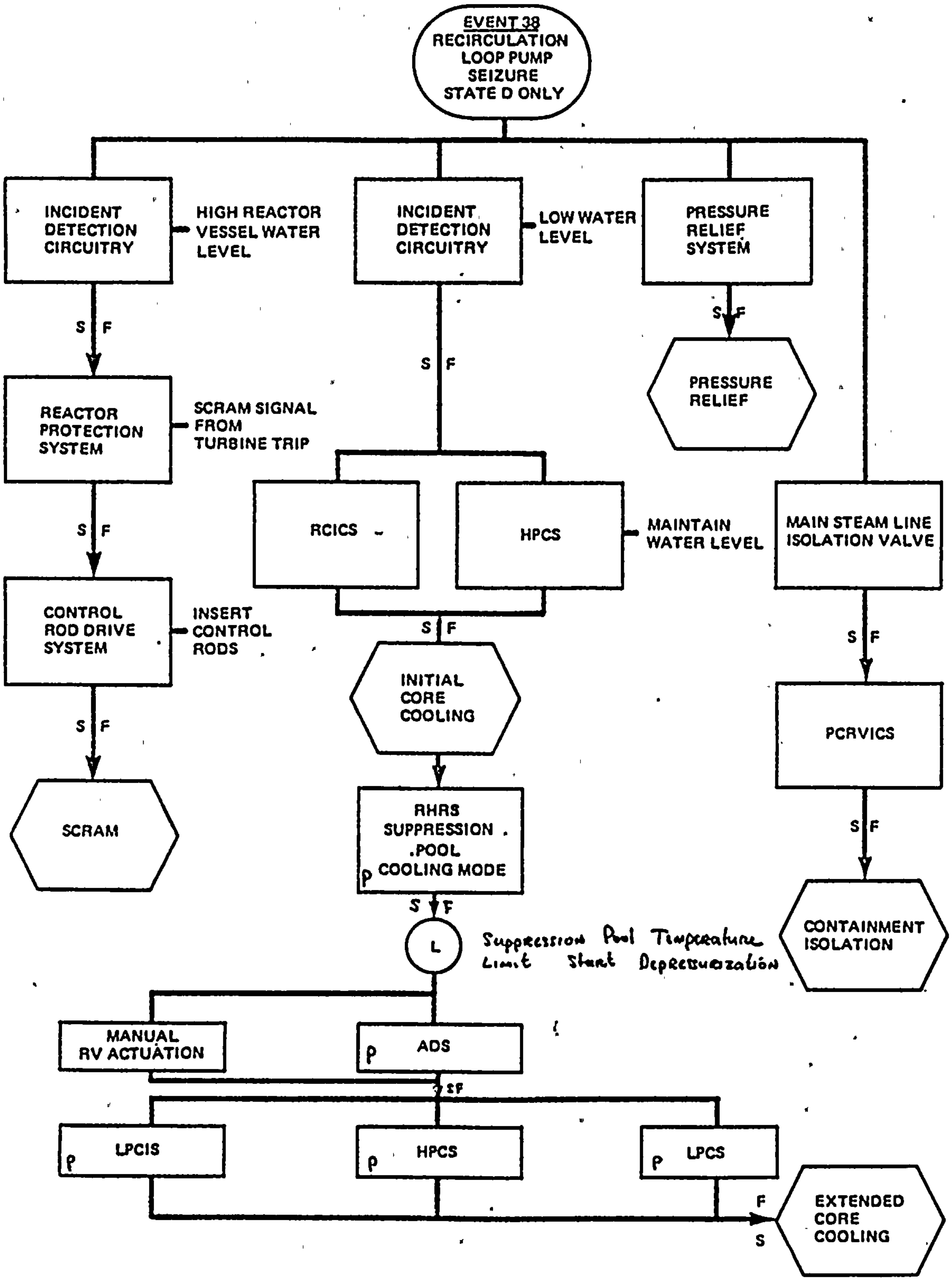
FIGURE 15.A.6-30



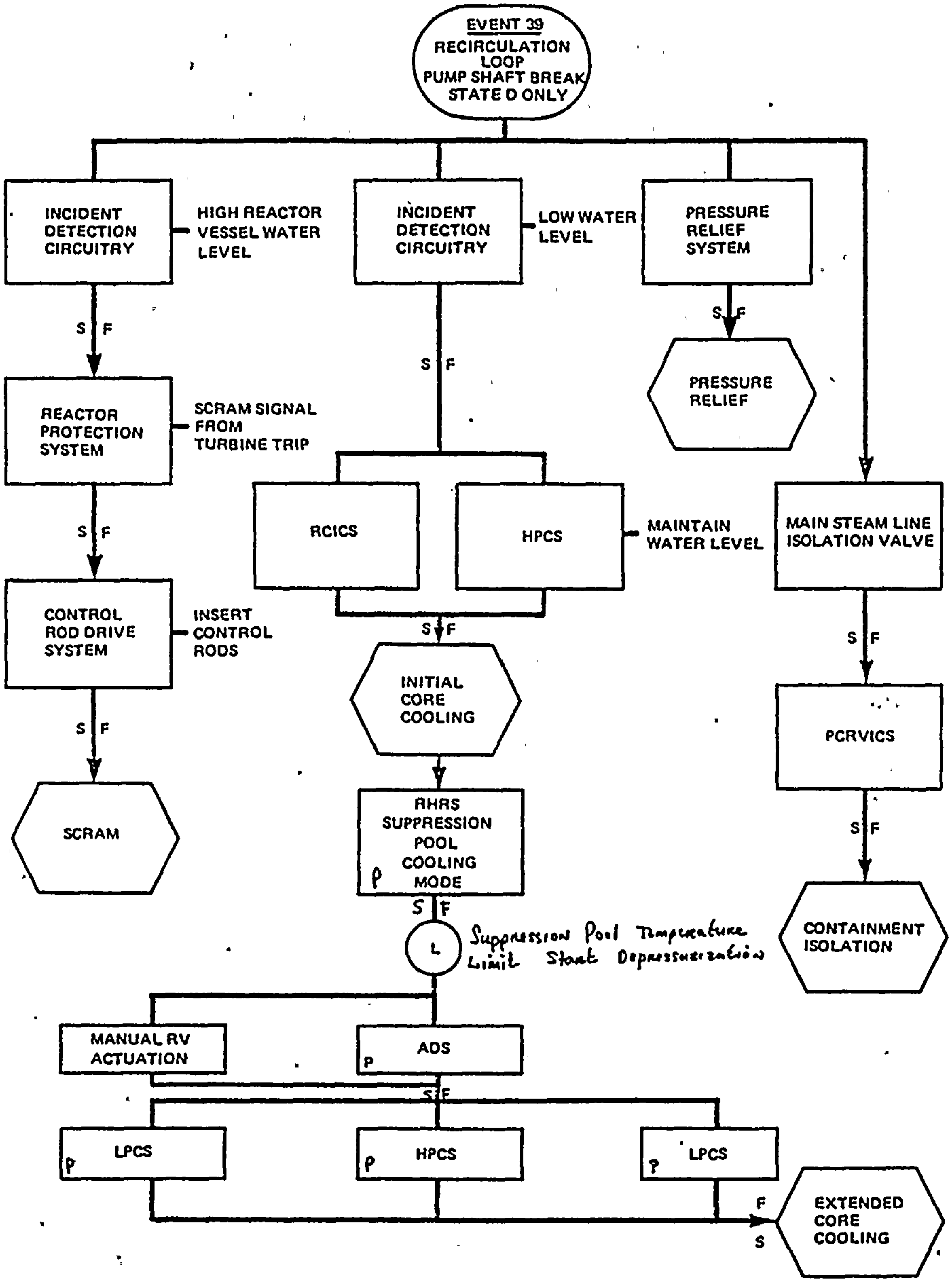
WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE MAIN TURBINE TRIP-WITHOUT BYPASS

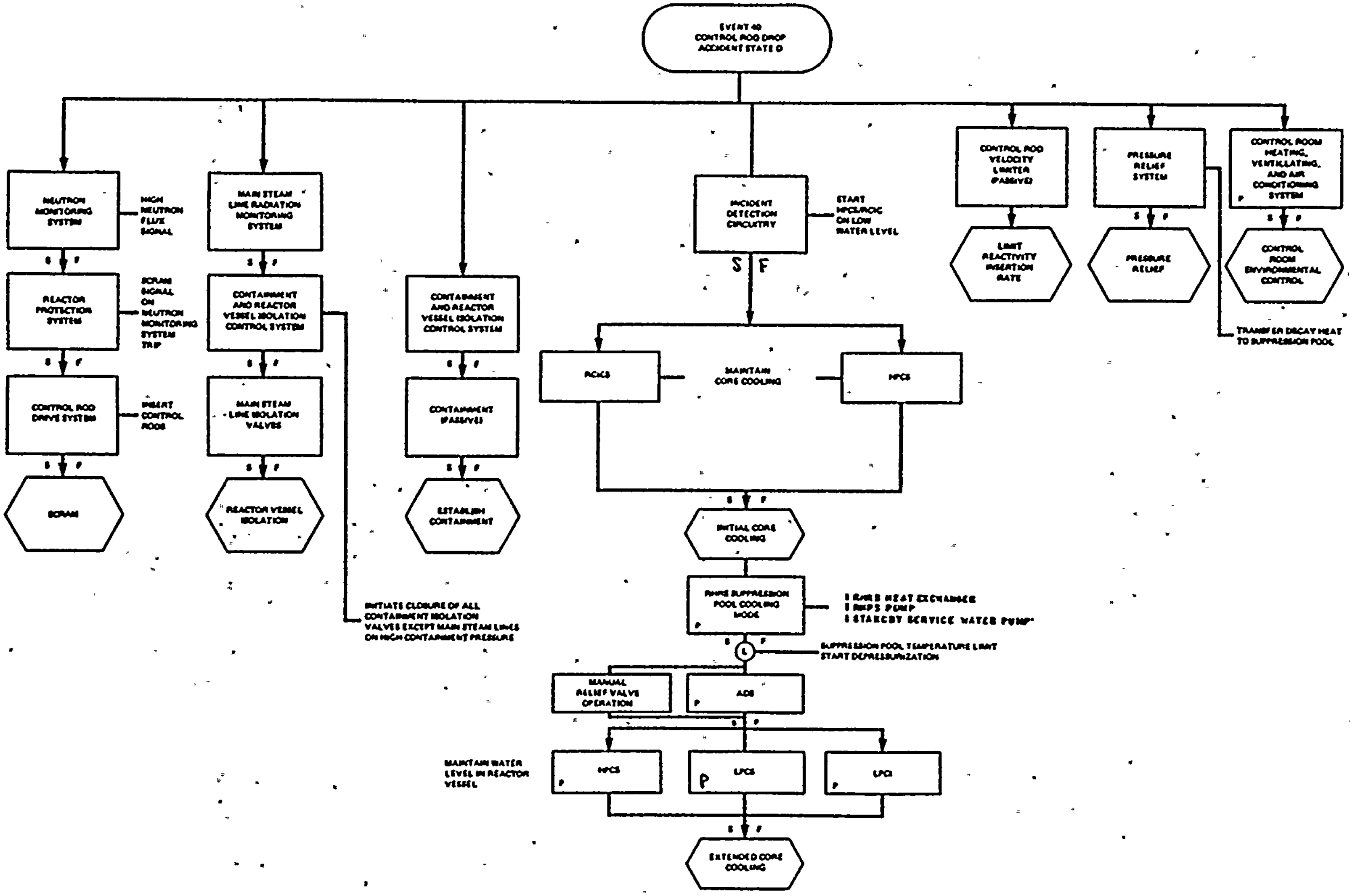
FIGURE 15.A.6-31



WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR RECIRCULATION LOOP PUMP SEIZURE	FIGURE 15.A.6-38



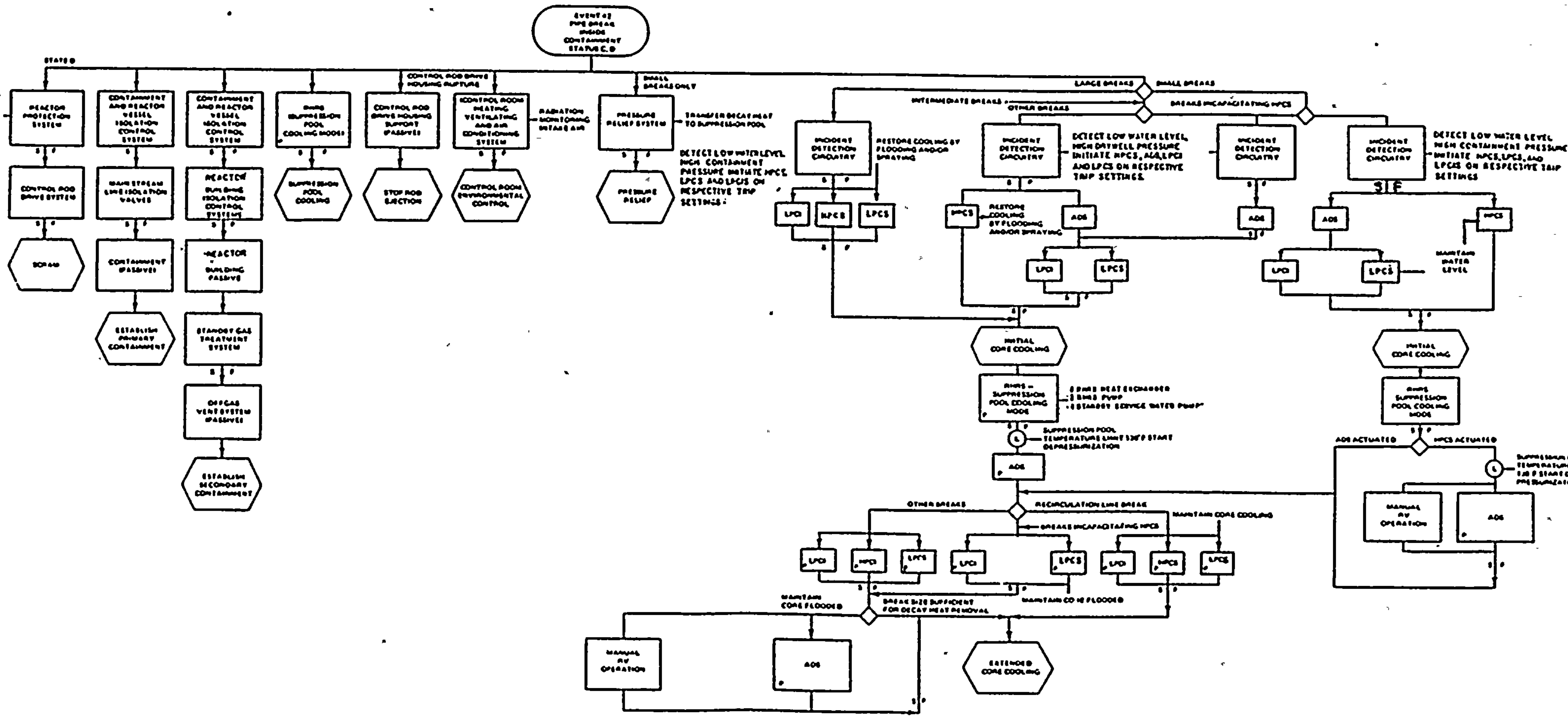
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCE FOR RECIRCULATION LOOP PUMP SHAFT BREAK	FIGURE 15.A.6-39



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR CONTROL ROD DROP ACCIDENT

FIGURE 15.A.6-40

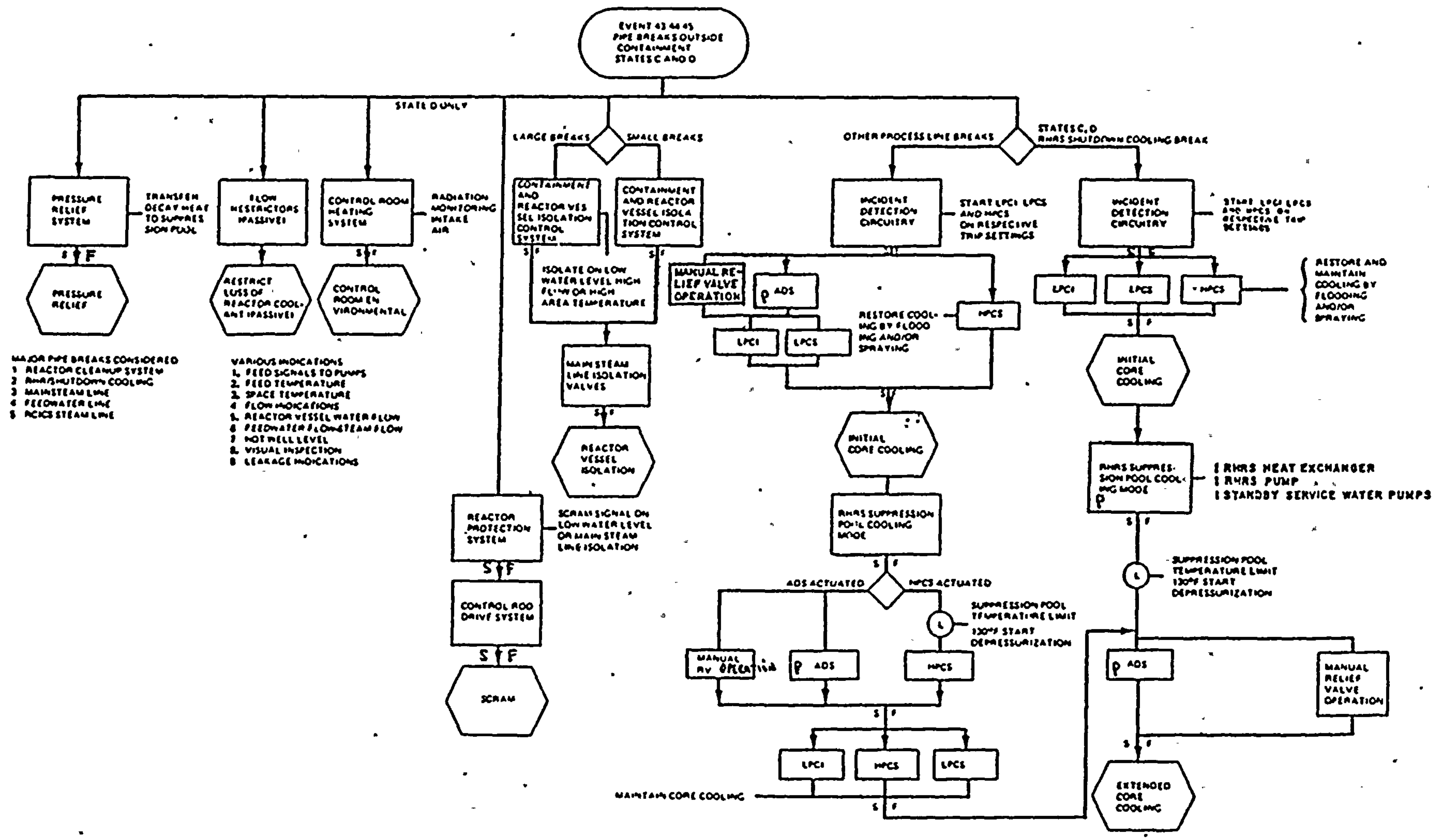


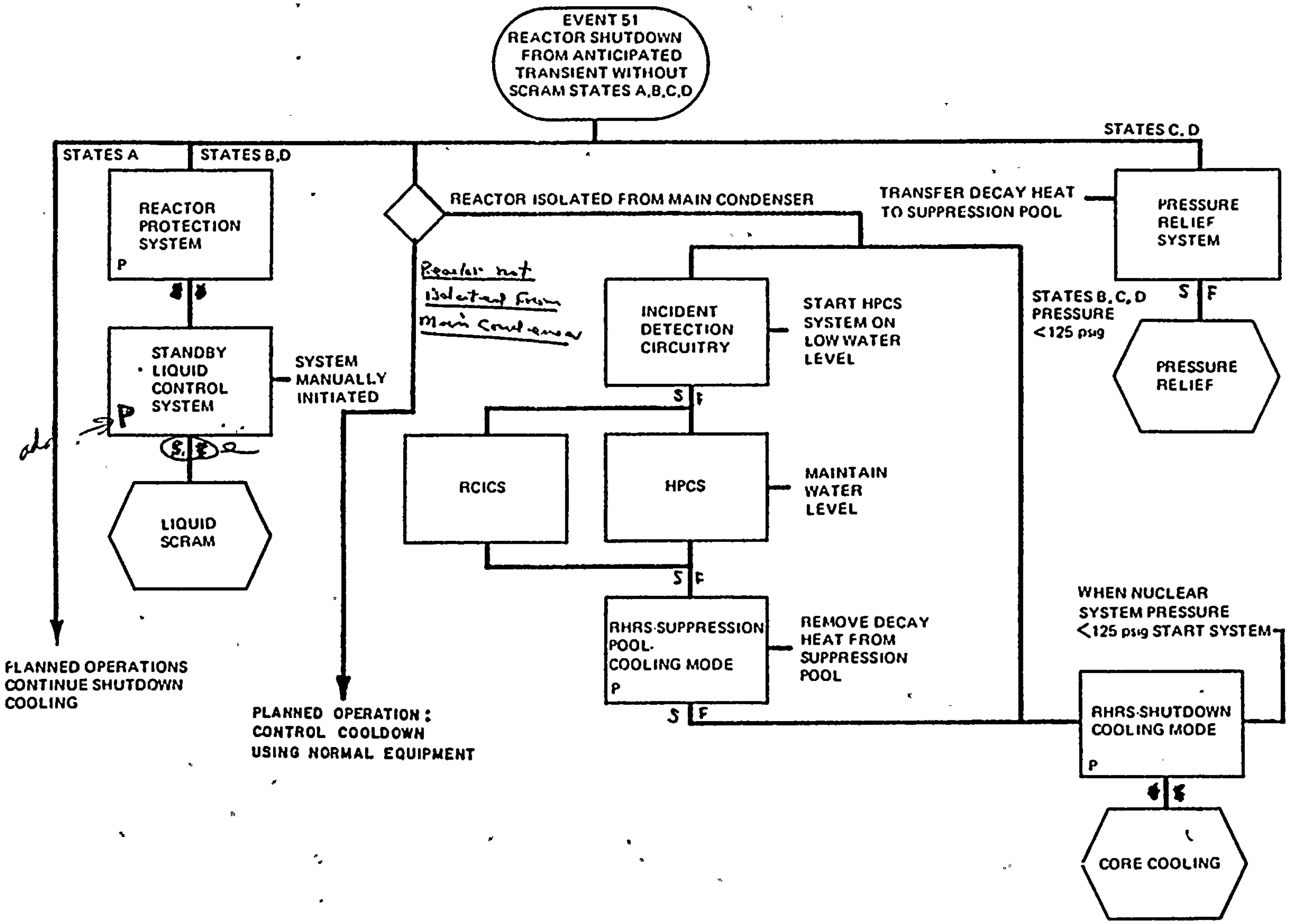
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	PROTECTION SEQUENCES FOR LOSS-OF-COOLANT PIPING BREAKS IN RCPB - INSIDE CONTAINMENT	FIG 15.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR LIQUID, STEAM, LARGE, SMALL PIPING BREAKS OUTSIDE CONTAINMENT

FIGURE
15.A.6-43
15.A.6-44
15.A.6-45

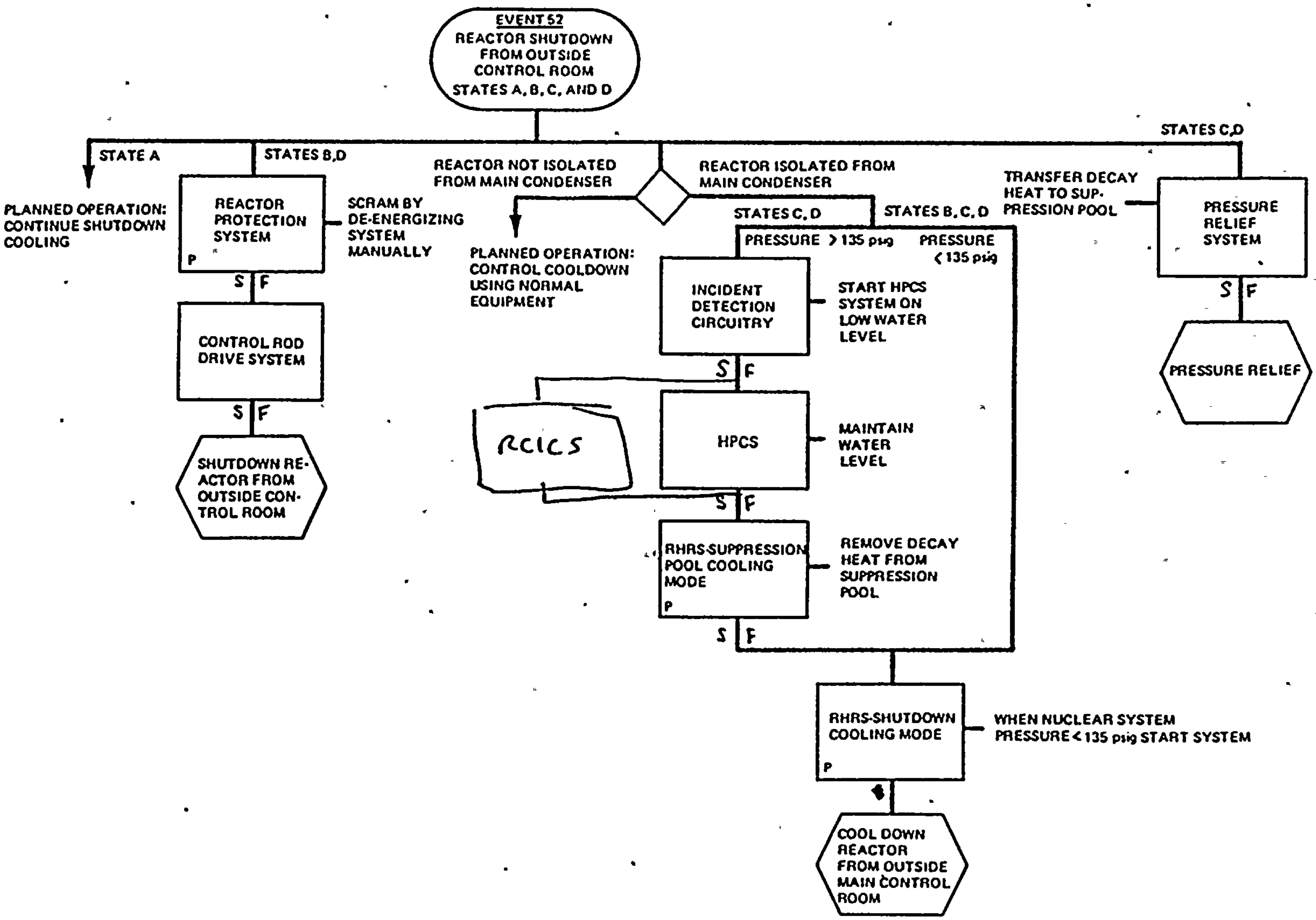




WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR REACTOR SHUTDOWN FROM ANTICIPATED TRANSIENT WITHOUT SCRAM

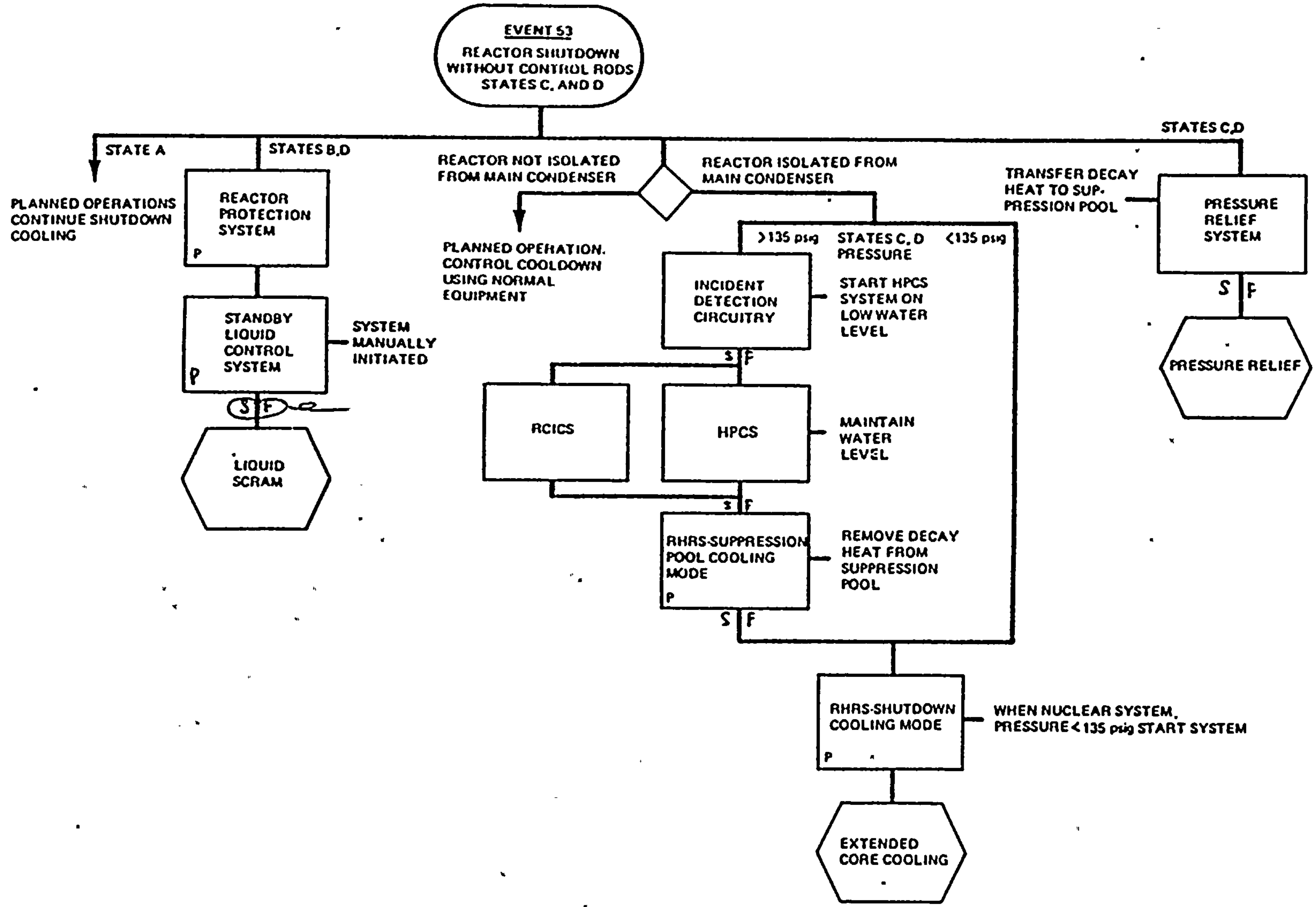
FIGURE 15.A.6-51



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR REACTOR SHUTDOWN-FROM OUTSIDE MAIN CONTROL ROOM

FIGURE 15.A.6-52



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NO. 2

PROTECTION SEQUENCE FOR REACTOR SHUTDOWN-WITHOUT CONTROL RODS

FIGURE 15.A.6-53

Q. 211.086
RSP
(15.1.2)

During recent meetings with GE, we have discussed whether non-safety-grade equipment can be assumed to function when analyzing anticipated transients. It is our understanding that one of the more limiting events is the failure of the feedwater controller which would result in a maximum flow demand. For this transient, the plant operating equipment which has a significant role in mitigating this event, are: (1) the turbine bypass system; and (2) the reactor vessel high water level trip (Level 8) that closes the turbine stop valves. To assure an acceptable level of performance, it is our position that the availability, the setpoints and the surveillance testing of this equipment be identified in the WNP-2 Technical Specifications. Accordingly, submit your plans for implementing this requirement along with any system modifications that may be required to satisfy our requirements in this matter.

Response:

As a means to assure an acceptable level of performance of both the turbine bypass system and the reactor vessel high water level trip logic, the Supply System will place these components under WNP-2 Technical Specification surveillance. For the L8 trip circuitry, the trip setpoints and surveillance frequency should be similar to that of the HPCS injection valve closure on high level logic presently controlled by Technical Specifications. Tentatively, a trip setpoint of +55.5" and a surveillance frequency of monthly functional checks and quarterly calibration is envisioned. A minimum number of two channels should be available in operational conditions 1 and 2. For the turbine bypass system, a setpoint, per se, does not apply. Valve operability will be performed monthly while at power with a DEH logic check performed at each refueling. Availability requirements will specify that all required valves must be operable in operational conditions 1 and 2.

Q. 211.087
(15.1)

It is not evident to us that the drop of 100° Fahrenheit which you assume in the feedwater temperature results in a conservative evaluation of the cold feedwater transient when the recirculation flow is manually controlled. For example, a feedwater temperature drop of about 150° Fahrenheit occurred at an operating BWR in this country as a result of a single failure of an electrical component. The electrical equipment malfunction which was a break-trip of a motor control center, caused a complete loss of all feedwater heating due to a total loss of extraction steam. Accordingly, submit: (1) a sufficiently detailed failure modes and effects analysis to demonstrate the conservatism of the 100° Fahrenheit feedwater temperature drop you assume considering the potential effects of any single electrical malfunction; or (2) calculations using a limiting feedwater temperature drop which clearly bounds current operating experience.

Further, reductions in feedwater temperature less than 100° Fahrenheit can occur which would represent more realistic (i.e., slower) changes in feedwater temperature with time. In particular, slow transients with the surface heat flux in equilibrium with the reactor power when the reactor scrams due to a feedwater temperature drop smaller than 100° Fahrenheit, could result in a larger change in the critical power ratio (CPR). Accordingly, evaluate the cold feedwater transient for all sequences of events that can cause a slow transient and demonstrate the conservatism of the values of the feedwater temperature drops, including the rate of change with respect to time, which you assume in your present transient analysis.

Response:

The GE feedwater heater system design specification to the A/E requires that the maximum temperature decrease which can be caused by bypassing feedwater heater(s) by any equipment single failure or operator error should be less than or equal to 100°F. This is the basis of the assumed drop of 100°F in feedwater temperature in the analysis. To verify proper design by the A/E, a review of the feedwater system will be performed during the start-up test program to determine the most limiting single failure or operator error in

terms of impact on feedwater temperature drop. A test will then be performed which simulates such a failure or error to confirm plant response, MCPR transient behavior and feedwater temperature drop.

From the analysis with the assumed drop of 100°F in feedwater temperature, it shows that reactor scram due to high thermal power occurs during the transient. It is evident that transients resulting from feedwater temperature decreases greater than 100°F would also result in reactor scram due to high thermal power. Therefore, the transients are not more severe than the one shown in the FSAR. The conclusion that a greater than 100°F feedwater temperature reduction does not result in more severe transients is substantiated by an analysis performed on the LaSalle docket in the response to LaSalle Question 212.142. Due to similarity of design, the analysis is applicable to WNP-2. The analysis assumed a feedwater temperature drop of 150°F which bounds observed operating experience.

It should be pointed out that a steady state condition (i.e., the surface heat flux in equilibrium with the neutron flux at the occurrence of scram) is assumed in determining MCPR during the transient. Therefore, reduction in feedwater temperature less than 100°F will not result in a larger ΔCPR than that reported in the FSAR.

Q. 211.088
(15.2)

In your evaluation of the generator load rejection transient, you assume 0.15 seconds for the full stroke closure time of the turbine control valve and state that it is conservative compared to an actual closure time of 0.2 seconds. However, in Table 15.2-2 of the FSAR, you indicate that the turbine control valves close in 0.07 seconds. Explain this apparent discrepancy. Additionally, the pressure peaks caused by closure times from the partially open to the fully closed position are not addressed in the FSAR. For full-stroke closure, the closure time you assume appears to be conservative in light of the information in the FSAR. However, for operation in the full arc (i.e., full throttling) mode, the closure times may be significantly less than 0.15 seconds for typical cases where the control valves are only partially open. We have two concerns with respect to this particular transient. Our first concern is that the minimum closure times for part-stroke may be less than those you assumed in your analysis. Our second concern is that your analysis, which is based on initial conditions which include 105 percent, nuclear boiler rated, steam flow and the control valves wide open, may result in a less conservative evaluation than the initial conditions at a somewhat lower power with the control valves partially open. Accordingly, demonstrate that control valve closure times smaller than 0.15 seconds do not result in unacceptable increases in the MCPR and in the reactor peak pressure. Alternatively, either provide justification that shorter closure times cannot occur or indicate a minimum closure time to be incorporated into the WNP-2 Technical Specifications.

Response:

In the evaluation of the generator load rejection transient as shown in Section 15.2-2, the closure characteristics of the turbine control valves are assumed such that the valves operate in the full arc mode and have a full stroke closure time, from fully open to fully closed, of 0.15 seconds. So Table 15.2-2 shows that turbine control valves close in 0.07 seconds, since the turbine control valves are initially partially open.

Sensitivity study shows that the most severe initial condition for this transient is when the reactor operates

at 105% NBR steam flow with the assumption of full arc operation, since the pressurization rate is higher at higher initial power level.

Other sensitivity study shows that turbine control valve closure times smaller than the assumed 0.15 seconds do not result in unacceptable increase in CPR and reactor peak pressure. For example, if the turbine control valve closure time is 0.10 seconds, the peak surface heat flux would increase by 1%, peak reactor pressure 1 psi. Since this transient is not the most limiting transient, which determines the operating CPR limit, the turbine control valve closure time will not affect the operating CPR limit.

Q. 211.089
(15.1.1)

For the transient resulting from a loss of feedwater heating while in the manual flow control mode, the thermal power monitor (TPM) is used to scram the reactor. Explain the need for the TPM and indicate the specific transients for which this trip signal initiates a reactor scram. Describe the surveillance testing of the TPM will be incorporated into the WNP-2 Technical Specifications.

Response:

If there were no high thermal power trip scram design available in the WNP-2 plant design, reactor scram during the loss of feedwater heating transient would occur when the neutron flux exceeds the high APRM flux scram setpoint. Usually, the high APRM flux scram setpoint is higher than the high thermal power scram setpoint by approximately 3-6%. Therefore, the loss of feedwater heating transient would be more severe without the high thermal power trip scram design. This would lead to higher operating CPR limit and reduce the flexibility of plant operation.

TPM scrams are applicable to those transients associated with slow neutron flux increases. One such transient would be the loss of feedwater heating (see the response to Question 211.087).

The surveillance testing of TPM will be defined in WNP-2 Technical Specifications. Typical wording is illustrated in the attached sections from the Standard Technical Specifications.*

*The Technical Specifications are under development and the attached is for information only.

3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-upscale scram trip setpoint (S) and flow biased simulated thermal power-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

$$S \leq (0.66W + (54)\%)\ T$$
$$S_{RB} \leq (0.66W + (42)\%)\ T$$

where: S and S_{RB} are in percent of RATED THERMAL POWER,
W = Loop recirculation flow in percent of rated flow,
T = Lowest value of the ratio of design TPF divided by the MTPF obtained for any class of fuel in the core, T greater than or equal to 1.0, and
Design TPF for 8 x 8 fuel = (2.43).

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to (25)% of RATED THERMAL POWER.

ACTION:

With the APRM flow biased simulated thermal power-upscale scram trip setpoint or the flow biased simulated thermal power-upscale control rod block trip setpoint less conservative than S or S_{RB}, as above determined, initiate corrective action within 15 minutes and restore S and S_{RB} to within the required limits within 2 hours or reduce THERMAL POWER to less than (25)% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The MTPF for each class of fuel shall be determined, the value of T calculated, and the flow biased scram and control rod block trip setpoints verified to be within the above limits or adjusted, as required:

a. At least once per 24 hours,

b. Within ( ) hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with MTPF greater than or equal to (2.43).

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
1. Intermediate Range Monitors:			
a. Neutron Flux - Upscale	2, 5(b)	3	1
	3, 4	2	2
b. Inoperative	2, 5(b)	3	1
	3, 4	2	2
2. Average Power Range Monitor:			
a. Neutron Flux - Upscale	2, 5(b)	2	1
	3, 4	2	2
b. Flow Biased Simulated Thermal Power - Upscale	1	2	3
c. Neutron Flux - Upscale	1	2	3
d. Inoperative	1, 2, 5(b)	2	4
e. LPRM	1, 2, 5	(c)	NA
3. Reactor Vessel Steam Dome Pressure - High	1, 2(d)	2	5
4. Reactor Vessel Water Level - Low, Level 3	1, 2	2	5
5. Main Steam Line Isolation Valve - Closure	1(e)	4	3
6. Main Steam Line Radiation - High	1, 2(d)	2	6
7. Primary Containment Pressure - High	1, 2(f)	2	5

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[(a)]	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - Upscale	S/U[(c)],S	S/U[(b)]	R	2
	S	W	R	3, 4, 5
b. Inoperative	NA	W	NA	2, 3, 4, 5
2. Average Power Range Monitor:				
a. Neutron Flux - Upscale	S/U[(c)],S	S/U[(b)], W	SA	2
	S	W	SA	3, 4, 5
b. Flow Biased Simulated Thermal Power - Upscale	S	S/U[(b)], W	W[(d)(e)], SA	1
c. Neutron Flux - Upscale	S	S/U[(b)], W	W[(d)], SA	1
d. Inoperative	NA	W	NA	1, 2, 5
e. LPRM	S	NA	(f)	1, 2, 5
3. Reactor Vessel Steam Dome Pressure - High	NA	M	Q	1, 2
4. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2
5. Main Steam Line Isolation Valve - Closure	NA	M	R	1
6. Main Steam Line Radiation - High	S	W[(g)]	R[(h)]	1, 2
7. Primary Containment Pressure - High	NA	M	Q	1, 2

TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - Upscale	NA
b. Inoperative	NA
2. Average Power Range Monitor*:	
a. Neutron Flux - Upscale	NA
b. Flow Biased Simulated Thermal Power - Upscale	$\leq$ (0.09**)
c. Fixed Neutron Flux - Upscale	$\leq$ (0.09)
d. Inoperative	NA
e. LPRM	NA
3. Reactor Vessel Steam Dome Pressure - High	$\leq$ (0.55)
4. Reactor Vessel Water Level - Low, Level 3	$\leq$ (1.05)
5. Main Steam Line Isolation Valve - Closure	$\leq$ (0.06)
6. Main Steam Line Radiation - High	NA
7. Primary Containment Pressure - High	NA
8. Scram Discharge Volume Water Level - High	NA
9. Turbine Stop Valve - Closure	$\leq$ (0.06)
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	$\leq$ (0.08)#
11. Reactor Mode Switch in Shutdown Position	NA
12. Manual Scram	NA

*Neutron detectors are exempt from response time testing. Response time shall be measured from the detector output or from the input of the first electronic component in the channel. (This provision is not applicable to Construction Permits docketed after January 1, 1978. See Regulatory Guide 1.18, November 1977.)

(**Not including simulated thermal power time constant.)

#Measured from start of turbine control valve fast closure.

Q. 211.090
(15.2)

Provide assurance that the plots of pressure with time in Section 15 of the FSAR are consistent with the initiation logic for the SRVs. For example, you may have modified the safety/relief system to prevent subsequent reopening of these valves during transients involving an increase in the reactor pressure to satisfy your present design bases for pool dynamic loads in the containment.

Response:

The plots of pressure with time in Section 15 of the FSAR are indeed consistent with the initiation logic for the SRVs. If changes to accommodate the Low-Low Set design are made in the future, the transient analyses will be revised accordingly. Currently, this feature is not necessary on WNP-2.

Q. 211.091
(15.4.5)

Provide the initial operating MCPR determined at 56 percent of rated power (nuclear boiler) and 36 percent of the core flow for the postulated failure of the recirculation flow control system while undergoing an increasing flow transient. In addition, provide the K_f* factors as a function of the core flow for both the automatic and manual flow control modes of operation. Provide the maximum flow control set-point calibration limit (e.g., 100 percent or 105 percent of rated flow) for the recirculation loop flow control valves used in the transient analysis. Additionally, we note that you reference the GE topical report, NEDO-10802, for the dynamic model which you used to simulate this event. However, NEDO-10802 does not describe the complete event. Accordingly, discuss in greater detail the overall method you used to calculate the change in the CPR.

Response:

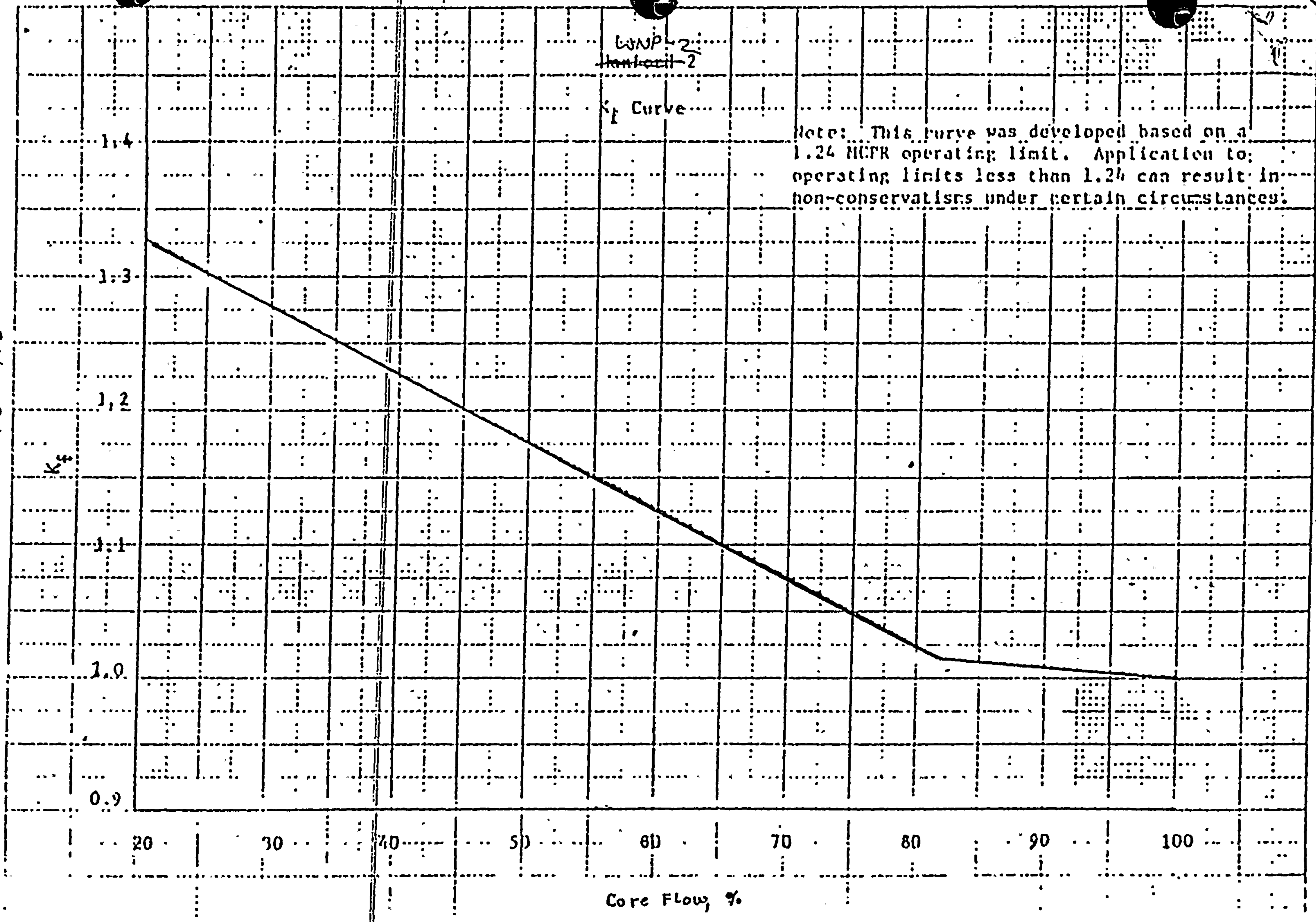
The initial operating MCPR at 56% of nuclear boiler rated power and 36% of core flow is 1.54.

A plot of the K_f factor vs. core flow appears on the attached figure. The mode of operation (automatic or manual) of the recirculation flow control system has no impact upon the K_f curve.

The K_f curve for WNP-2 is based upon 114% maximum flow. The maximum flow will be limited to a value of 102.5% maximum. Therefore, the K_f curve is conservative.

The method of calculating the change in CPR is described in the General Electric BWR Thermal Analysis Bases (GETAB): data, correlation and design application, NEDO-10958A.

*K_f is defined as the ratio of the MCPR at a given reactor coolant flow rate to the MCPR at 100% power (i.e., 1.20).


WNP-2
~~Hanford-2~~
K_f Curve
Note: This curve was developed based on a 1.24 MCPR operating limit. Application to operating limits less than 1.24 can result in non-conservatisms under certain circumstances.
1.4
1.3
1.2
1.1
1.0
0.9
K_f
20
30
40
50
60
70
80
90
100
Core Flow, %

Q. 211.092
(15.3.3)

In Table 15.3-5 of the FSAR, you take credit for non-safety grade equipment to terminate the postulated accident involving seizure of the recirculation pump. However, it is our position (refer to Section 15.3.3, Revision 1, NUREG-75/087 of the Standard Review Plan) that only safety grade equipment can be used and that the required safety functions must be accomplished assuming the worst single failure of an active component. Accordingly, reevaluate this accident with the specific criteria cited above. Indicate the resulting change in the CPR and the percentage of fuel rods which would be in boiling transition for this postulated accident.

Response:

The recirculation pump seizure event was reclassified as an accident with the introduction of the General Electric BWR Thermal Analysis Basis Report (NEDO-10958-A) because of the highly unlikely nature of this event. The FSAR analysis assumes that the attendant water level swell will cause a high level (L8) trip thereby shutting down the main turbine and feed pump turbines, and indirectly initiating scrams as a result of the main turbine trip. The FSAR analysis also explains (Section 15.3.1.2.3.2 as referenced in 15.3.3.2.3) that a turbine trip can eventually occur even in the event of failure of the non-single failure proof turbine trip signal circuitry. Pump seizure event analyses have shown that, although coolant flow rate drops rapidly, MCPR does not decrease significantly before fuel surface heat flux begins dropping enough to restore greater thermal margins as the plant intrinsically responds to the reduced flow rate.

The pump seizure event is a very mild accident in relation to other accidents such as the DBA-LOCA addressed in the FSAR. This is easily verified by consideration of the two events. In both accidents, the recirculation driving loop flow is lost extremely rapidly - in the case of seizure, stoppage of the pump occurs; for the DBA-LOCA, the severance of the line has a similar, but more rapid and severe influence. Following a pump seizure event, flow continues, water level is maintained, the core remains submerged, and this provides a continuous core cooling mechanism. However, for the DBA-LOCA complete flow stoppage occurs and water level

decreases due to loss of coolant resulting in uncovery of the reactor core and subsequent overheating of the fuel rod cladding. Also, complete depressurization occurs with the DBA-LOCA, while reactor pressure does not significantly decrease for the pump seizure event. Clearly, the increased temperature of the fuel cladding and the reduced reactor pressure for the DBA-LOCA both combine to yield a much more severe stress and potential for cladding perforation for the DBA-LOCA than for the pump seizure. Therefore, it can be concluded that the potential effects of the hypothetical pump seizure accident are very conservatively bounded by the effects of the DBA-LOCA and a specific core performance analysis or radiological evaluation is not considered necessary.

This has been found to be an acceptable generic licensing basis for this event by the NRC staff (see the General Electric LTR "Generic Reload Fuel Application" NEDO-24011-A).

In addition, the non-safety-related equipment used in the analysis (L8 trip/turbine bypass system) has been made more reliable based on Technical Specification surveillance. See the response to Question 211.086.

Q. 211.093
(15.1.2)

For the transient resulting from a postulated failure of the water controller during maximum flow demand, you indicate a feedwater flow of 146 percent in Table 15.1-3 of the FSAR. However, you indicate in Section 15.1.2.3.2 that the feedwater flow is 135 percent for the maximum flow setting in simulating this transient. Clarify this apparent discrepancy.

Response:

Section 15.1.2.3.2 states that 135% feedwater runout flow will result if the operating pressure is at the design pressure of 1060 psig. In the analysis, the operating dome pressure is 1020 psig, hence higher runout flow will result.

Q. 211.094
(15.1.2)

When a sudden increase in feedwater flow occurs, there will be a corresponding drop in the feedwater temperature which contributes to the reactivity increase during the first part of this transient. For example, the combination of a drop in the feedwater temperature and a smaller maximum flow rate could cause a Level 8 trip with the surface heat flux close to the flux scram setpoint. If you have assumed that the feedwater temperature into the reactor vessel has remained constant, reanalyze this transient to include the effect of the variation in the feedwater temperature on the MCPR. Provide your basis for determining the time variation in the feedwater temperature in the reactor vessel. Demonstrate that a smaller increase in the feedwater flow rate than the one you analyzed, in conjunction with the change in feedwater temperature, does not result in a lower MCPR.

Response:

It is true that there will be a drop in the feedwater temperature with an increase in feedwater flow. However, the feedwater heater usually has a large time constant (in minutes, not in seconds) so the feedwater temperature change is very slow. In addition, there is a long transport delay time before the cold feedwater reaches the vessel. Therefore, it is expected that the feedwater temperature change during the first part of the feedwater controller failure (maximum demand) transient is insignificant, and its effect on the transient severity is minimal.

Q. 211.095
(15.1.4)

In your analysis of an inadvertent opening of an SRV in Section 15.1.4.2.1.1 of the FSAR, you state that a plant shutdown "should" be initiated if the valve cannot be closed. Indicate how much time the operator has to initiate plant shutdown before exceeding the proposed WNP-2 Technical Specification limits for the suppression pool temperature.

Response:

The operator will have the time period between the valve first sticking open and the bulk pool temperature reaching 110°F before he must scram the reactor to be in compliance with the Technical Specifications.

If it is assumed that the suppression pool is at its maximum operating temperature and minimum operating volume with no pool cooling systems in operation when the valve first opens, the operator will have more than 8.7 minutes before the pool scram temperature of 110°F is reached. If the above worst case assumptions were relaxed, the time for operator action would be increased.

Q. 211.096
(15.2.6)

You indicate in your analysis of the transient resulting from a postulated loss of off-site power that closure of the MSIV's occurs at 30 seconds after the start of the transient due to a loss of condenser vacuum. Our concern in this matter is that the MSIV's may close at an earlier time in the transient, thereby causing higher system pressures than your analysis indicates. Apparently, you take credit for operation of the MSIV air accumulator since the normal air supply to the MSIV's would trip at the start of this particular transient. Discuss the design provisions incorporated into the WNP-2 facility which prevent closure of the MSIV's any earlier than 30 seconds after the start of this transient. Additionally, discuss your verification testing which will demonstrate that the MSIV performance assumed in your analysis will be achieved.

Response:

Section 15.2.6 has been reanalyzed and revised to take into consideration that reactor scram and MSIV closure are initiated at two seconds due to loss of power to the scram and MSIV solenoids. This applies to both loss of auxiliary power transformers transient and loss of all grid connections transient. Two seconds is assured due to the inertia of the RPS MG set flywheels which provide power to the MSIV solenoids. See the response to Question 211.097. Also, the pertinent items in Table 15.0-1 are revised accordingly. During the startup test program a generator load rejection/loss of all grid connections test will be performed to verify proper plant response in comparison to analysis assumptions.*

*Draft FSAR page changes attached.

TABLE 15.0-1

RESULTS SUMMARY OF TRANSIENT EVENTS APPLICABLE TO WNP-2

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux % NBR	Maximum Dome Pressure psig	Maximum Vessel Pressure psig	Maximum Steam Line Pressure psig	Maximum Core Average Surface Heat Flux % of Initial	Minimum CPR -	Frequency Category*	Duration of Blowdown: No. of Valves 1st Blowdown	Duration of Blowdown: Duration of Blowdown sec
15.1		DECREASE IN CORE COOLANT TEMPERATURE									
15.1.1	15.1-2	Loss of Feedwater Heater, Manual Flow Control	124.2	1030	1070	1001	117.1	1.08	a		
15.1.2	15.1-3	Feedwater Cntl Failure, Max Demand	176.0	1141	1170	1124	110.6	1.09	a	18	5.8
15.1.3	15.1-4	Pressure Regulator Fail-Open	104.3	1098	1117	1097	100.1	>1.18**		2	6.4
15.1.4		Inadvertent Opening of Safety or Relief Valve	SEE TEXT						a		
15.1.6		RHR Shutdown Cooling Malfunction Decreasing Temperature	SEE TEXT						a		
15.2		INCREASE IN REACTOR PRESSURE									
15.2.1		Pressure Regulator Fail - Closed	SEE 15.2.2 and 15.2.3 W/Bypass on						a		
15.2.2	15.2-1	Generator Load Rejection, Bypass-On	165.1	1137	1165	1122	103.3	1.15	a	18	5.5
15.2.2	15.2-2	Generator Load Rejection, Bypass-Off	254.5	1165	1193	1148	110.5	1.05	b	18	8.2
15.2.3	15.2-3	Turbine Trip, Bypass-On	147.5	1136	1163	1121	101.7	1.18	a	18	5.5
15.2.3	15.2-4	Turbine Trip, Bypass-Off	233.7	1163	1191	1147	108.9	1.07	b	18	8.2
15.2.4	15.2-5	Inadvertent MSIV Closure	186.2	1154	1191	1146	100.0	>1.20**	a	18	5.7
15.2.5	15.2-6	Loss of Condenser Vacuum	157.5	1135	1162	1120	102.6	>1.07**	a	18	5.4
15.2.6	15.2-7	Loss of Auxiliary Power Transformers	104.3	~~1088~~ 1153	~~1101~~ 1172	~~1086~~ 1149	100.0	~1.24**	a	0	0

TABLE 15.0-1 - (Continued)

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux % NBR	Maximum Dome Pressure psig	Maximum Vessel Pressure	Maximum Steam Line Pressure psig	Maximum Core Average Surface Heat Flux % of Initial	Minimum CPR -	Frequency Category*	Duration of Blowdown: No. of Valves 1st Blowdown	Duration of Blowdown: Duration of Blowdown sec
15.2.6	15.2-8	Loss of All Grid Connections	144.2 ~~140.7~~	1157 ~~1136~~	1177 ~~1163~~	1137 ~~1121~~	101.6 ~~101.1~~	>1.15**	a	18	5.5
15.2.7	15.2	Loss of all Feedwater Flow	104.3	1095	1107	1095	100.0	~1.24**	a	2	6.0
15.2.8		Feedwater Piping Break	SEE 15.6.6								
15.2.9		Failure of RHR Shutdown Cooling	SEE TEXT								
15.3		DECREASE IN REACTOR COOLANT SYSTEM FLOW-RATE									
15.3.1	15.3-1	Trip of One Recirculation Pump Motor	104.4	1021	1061	994	100.0	~1.24**	a	0	0
15.3.1	15.3-2	Trip of Both Recirculation Pump Motors	104.4	1104	1116	1100	100.1	~1.24**	a	6	5.3
15.3.2	15.3-3	Fast Closure of One Main Recirc Valve	104.3	1101	1115	1097	100.0	~1.24**	a	2	6.8
15.3.2	15.3-4	Fast Closure of Two Main Recirc Valves	104.4	1105	1115	1100	100.0	~1.24**	a	6	5.4
15.3.3	15.3-5	Seizure of One Recirculation Pump	104.3	1105	1117	100	100.2	~1.24**	c	6	5.4
15.3.4		Recirc Pump Shaft Break	SEE 15.3.3								
15.4		REACTIVITY AND POWER DISTRIBUTION ANOMALIES									
15.4.1.1		RWE - Refueling	SEE TEXT						b		
15.4.1.2		RWE - Startup	SEE TEXT						b		
15.4.2		RWE - At Power	SEE TEXT					1.17	a		
15.4.3		Control Rod Misoperation	SEE 15.4.1 and 15.4.2								
15.4.4	15.4-6	Abnormal Startup of Idle Recirculation Loop	94.2	981	995	970	146.6	>1.06**	a		

See insert attached.

~~a. Recirculation pumps are tripped at a reference~~ time, t=0, with normal coastdown times.

b. Within 10 seconds, the loss of main condenser circulating water pumps causes condenser vacuum to drop to the turbine trip setting. However, the L8 high water level set point is reached earlier, tripping the main turbine and feedwater turbines after the set point is exceeded.

c. At approximately 30 seconds, the loss of condenser vacuum is expected to reach the bypass ~~closure set point. See Table 15.2-8.~~

Operation of the HPCS and RCIC system functions are not simulated in this analysis. Their operation occurs at some time beyond the primary concerns of fuel thermal margin and overpressure effects of this analysis.

15.2.6.2.2.2 Loss of All Grid Connections

Same as 15.2.6.2.2.1 with the following additional concern.

The loss of all grid connections is another feasible, although improbable, way to lose all auxiliary power. This event would add a generator load rejection to the above sequence at time, t=0. The load rejection immediately forces the turbine control valves closed, causes a scram and initiates recirculation pump trip (RPT) (already tripped at reference time t=0).

15.2.6.2.3 The Effect of Single Failures and Operator Errors

Loss of the auxiliary power transformers in general leads to a reduction in power level due to rapid pump coastdown with pressurization effects due to ~~turbine trip occurring after the reactor scram has occurred.~~ MSIV closure resulted from loss of power to the solenoids. Additional failures of the other systems assumed to protect the reactor would not result in an effect different from those reported. Failures of the protection systems have been considered and satisfy single failure criteria and as such no change in analyzed consequences is expected. See 15A for details on single failure analysis.

Insert to Page 15.2-48:

a. Recirculation pumps and condenser circulatory water pumps trip off at time = 0. Recirculation pumps coast down with the fastest rate specified in the Nuclear Boiler Systems TDS.

b. Due to loss of power to the scram and MSIV relay solenoids, reactor scrams and MSIV closure is initiated at two seconds time.

c. Feedwater turbines trip off at four seconds due to MSIV closure at two seconds.

15.2.6.3 Core and System Performance

15.2.6.3.1 Mathematical Model

The computer model described in 15.1.1.3.1 was used to simulate this event.

Operation of the RCIC or HPCS systems is not included in the simulation of this transient, since startup of these pumps does not permit flow in the time period of this simulation.

15.2.6.3.2 Input Parameters and Initial Conditions

15.2.6.3.2.1 Loss of Auxiliary Power Transformers

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2 and under the assumed systems constraints described in 15.2.6.2.2.

15.2.6.3.2.2 Loss of All Grid Connections

Same as 15.2.6.3.2.1

15.2.6.3.3 Results

15.2.6.3.3.1 Loss of Auxiliary Power Transformers

Figure 15.2-7 shows graphically the simulated transient. ~~The initial portion of the transient is similar to the loss-of-feedwater transient. Between 5.88 and 30 seconds turbine trip, scram, main steam line isolation valve closure, and bypass valve closure occur~~.

Sensed level drops to the RCIC and HPCS initiation set point at approximately ~~45~~ 48 seconds after loss of auxiliary power. The RHR, in the steam condensing mode, is initiated to dissipate the heat.

There is no significant increase in fuel temperature or decrease in the operating MCPR value, fuel thermal margins are not threatened and the design basis is satisfied.

Between 0 and 4 seconds RPT, scram, MSIV closure, and feedwater turbine trip occur.

15.2.6.3.3.2 Loss of All Grid Connections

Loss of all grid connections is a more general form of loss of auxiliary power. It essentially takes on the characteristic response of the standard full load rejection discussed in 15.2.2. Figure 15.2-8 shows graphically the simulated event. Peak neutron flux reaches ~~140.7~~ 144.2% of NB rated power while fuel surface heat flux peaks ~~at~~ ~~101.1~~ 101.6% of initial value. Peak fuel centerline temperature rise is only ~~60~~ 66 °F.

15.2.6.3.4 Consideration of Uncertainties

The most conservative characteristics of protection features are assumed. Any actual deviations in plant performance are expected to make the results of this event less severe.

Operation of the RCIC or HPCS systems is not included in the simulation of the first 50 seconds of this transient. Startup of these pumps occurs in the latter part of this time period but these systems have no significant effect on the results of this transient.

~~The trip of the feedwater turbines may occur earlier than simulated if the inertia of the condensate and booster pumps is not sufficient to maintain feedwater pump suction pressure above the low suction pressure trip set point. The simulation assumes sufficient inertia and thus the feedwater pumps are not tripped until the time that level reaches the high water level trip set point (L8).~~

Following main steam line isolation and prior to RHR initiation the reactor pressure is expected to increase until the safety/relief valve set points are reached. During this time the valves operate in a cyclic manner to discharge the decay heat to the suppression pool.

15.2.6.4 Barrier Performance

15.2.6.4.1 Loss of Auxiliary Power Transformers

The consequences of this event do not result in any significant temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel or containment

TABLE 15.2-9

SEQUENCE OF EVENTS FOR FIGURE 15.2-7

Time-sec	Event
0	Loss of auxiliary power transformers occurs.
0	Recirculation system pump motors are tripped.
0	Condensate and booster pumps are tripped.
0	Condenser circulating water pumps are tripped.
	see insert attached.
~~5.88~~	~~Main turbine and feedwater turbines are tripped on L8 high water level.~~
~~5.88~~	~~Turbine bypass operation initiated by turbine trip.~~
~~5.89~~	~~Reactor scram initiated when turbine stop valves reach 90% open position.~~
~~5.98~~	~~Turbine stop valves closed and turbine bypass starts to open to regulate pressure.~~
~~30.0~~	~~Low condenser vacuum initiates closure of turbine bypass valves and main steam line isolation valves.~~
~~30.4 (est.)~~	~~Turbine bypass valves closed.~~
~~33.0~~	~~Main steam line isolation valves closed.~~

Insert to Page 15.2-52:

2	Reactor scrams due to loss of power to the scram solenoid.
2	MSIV closure is initiated due to loss of power to MSIV solenoids.
4	Feedwater turbines trip off due to MSIV closure at two seconds.
4.71	Group 1 safety/relief valves actuated.
4.84	Group 2 safety/relief valves actuated.
4.98	Group 3 safety/relief valves actuated.
5.14	Group 4 safety/relief valves actuated.
5.43	Group 5 safety/relief valves actuated.

TABLE 15.2-9 - (Continued)

Time-sec	Event
~~44.6~~ (est.) 48.3	RCIC and HPCS systems initiation on low water level (L2), (not simulated).
50+	Group 1 relief valves cycle open and close on pressure.

TABLE 15.2-10

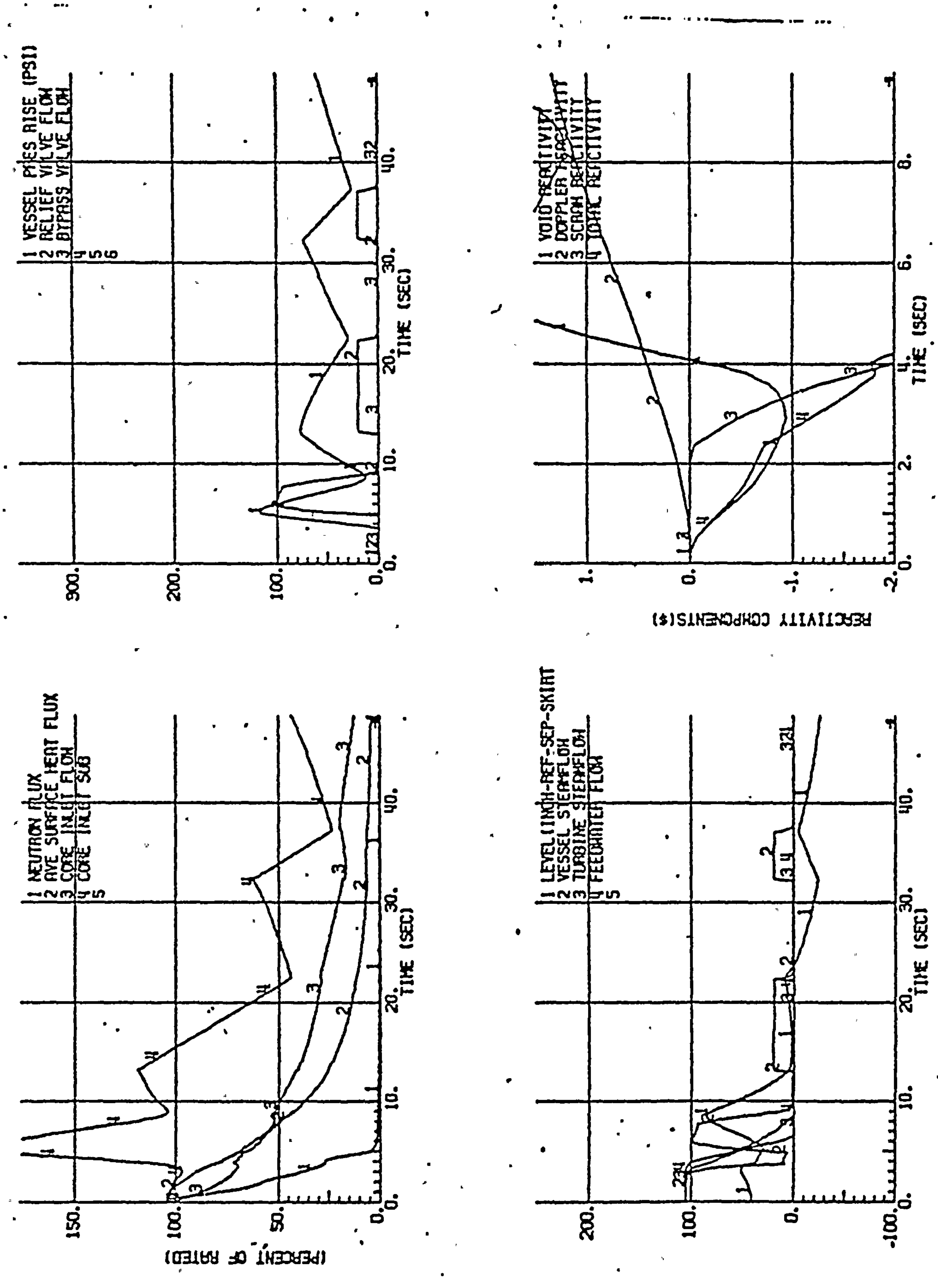
SEQUENCE OF EVENTS FOR FIGURE 15.2-8

Time-sec	Event
(-)0.015 (approx.)	Loss of Grid causes turbine-generator to detect a loss of electrical load.
0	Turbine-generator power-load unbalance (PLU) devices trip to initiate turbine control valve fast closure and turbine bypass system operation.
0	Condenser circulating water pumps are tripped.
0	Recirculation system pump motors are tripped.
0	Fast control valve closure initiates a reactor scram trip.
0	Feedwater condensate and booster pumps are tripped.
.002	Scram circuit is tripped on turbine-generator trip
0.07	Turbine control valves closed.
0.10	Turbine bypass valves start to open to regulate pressure.
1.58	Group 1 safety relief valves actuated.
1.73	Group 2 safety relief valves actuated.
1.89	Group 3 safety relief valves actuated.
2.00	Main steamline isolation is initiated due to loss of power to the solenoids
2.09	Group 4 safety relief valves actuated.
~~2.45~~ 2.49	Group 5 safety relief valves actuated.

TABLE 15.2-10 - (Continued)

Time-sec	Event
4.~~6~~0	Feedwater turbines trip ~~on L8 high water level~~. due to MSIV closure at 2 seconds.
5.1 (est.)	Group 5 safety relief valves start to close.
7.2 (est.)	All relief groups closed.
~~30.0~~	~~Closure of main steam line isolation valves and turbine bypass valves initiated by low condenser vacuum.~~
~~40.3~~ 35.7 (est.)	RCIC and HPCS systems operation initiated on L2 low water level (not simulated).
50+	Group 1 relief valves cycle open and close on pressure.

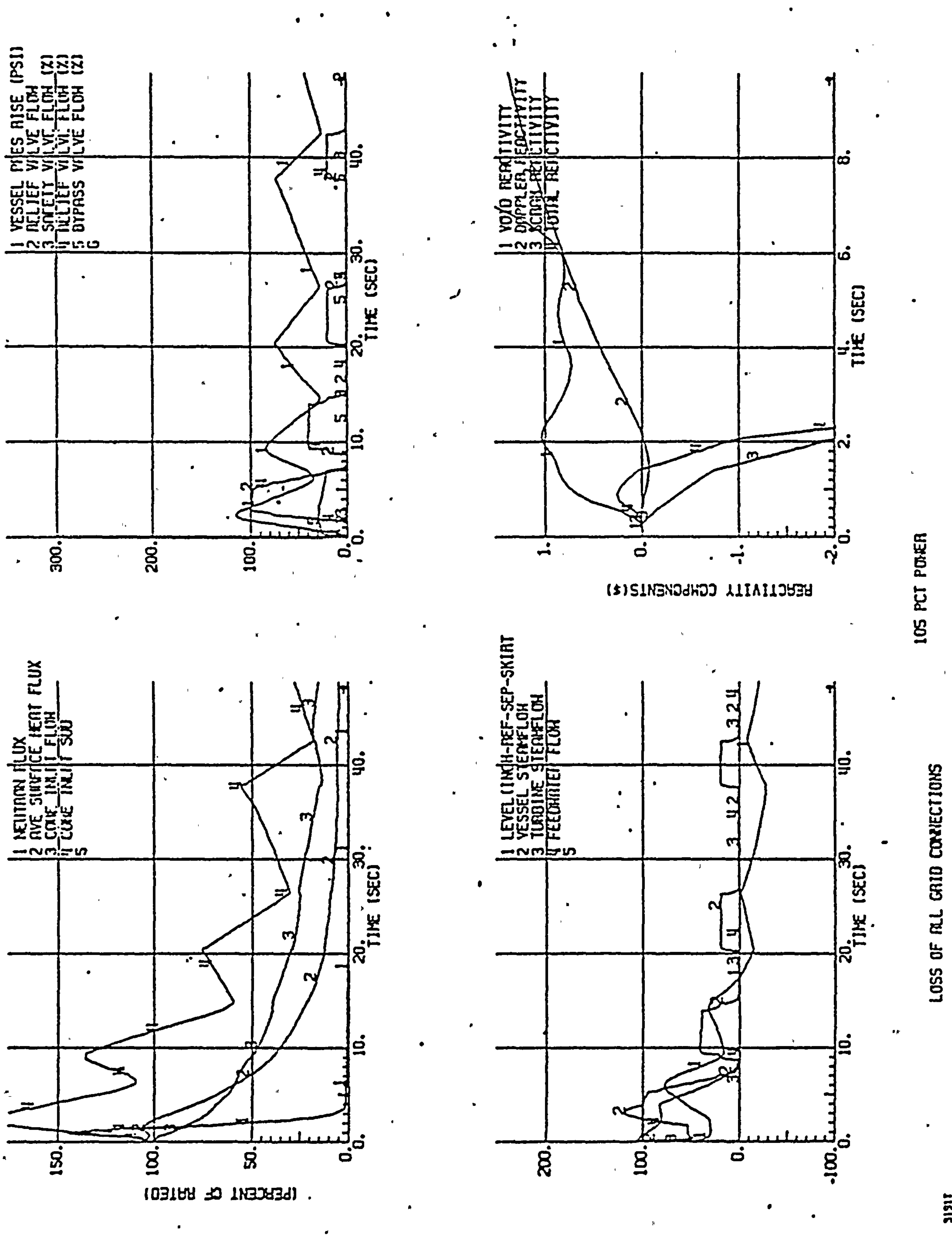
WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	LOSS OF AUXILIARY POWER TRANSFORMERS	FIGURE 15.2-7



105 PCT POWER

LOSS OF AUXILIARY POWER TRANSFORMER

WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 2	LOSS OF ALL GRID CONNECTIONS	FIGURE 15.2-8



Q. 211.097
(6.3)

We have a similar concern to that stated above regarding the potential for MSIV closures times that may be shorter than those assumed in your analyses of the transient resulting from a loss of off-site power since this loss of power could generate an isolation signal that would close the MSIV's. Indicate the sources of electrical power for the MSIV isolation logic and the isolation actuators. State whether these power sources would be available following a loss of off-site power. Indicate whether the MSIV isolation logic and the isolation actuators could fail in a manner which would initiate an MSIV isolation signal on loss of off-site power.

Response:

The MSIV isolation logic and air pilot valve solenoid (actuators) receive electrical power from the Reactor Protection System (RPS) motor/generator set buses in the following arrangement:

> Isolation Logics "A" and "C" and one pilot solenoid for each MSIV (inboard and outboard) receive electrical power from RPS bus "A" while logics "B" and "D" and the second pilot solenoid on each MSIV is powered from RPS bus "B".

As a result of this power supply configuration, an MSIV closure will not result from the loss of power to a single RPS bus. However, a complete loss of off-site power will result in loss of both RPS buses and an MSIV closure after the RPS motor generators voltage drops. (Approximately 15 seconds).

The logic and actuators are powered in such a manner that loss of power to a single logic channel or pilot solenoid group (i.e., blown fuse, open circuit or ground) will not cause an MSIV closure.

The RPS buses are powered from the standby power system and would be available following a loss of off-site power since diesel generator power becomes available in approximately 10 seconds.

See the response to Question 211.096 for the significance of these response times.

Q. 211.098
(15.0)

We are concerned that operation of the WNP-2 facility with partial feedwater heating might occur during routine maintenance or as a result of a decision on your part to operate with a lower feedwater temperature near the end of a fuel cycle. Demonstrate that this mode of operation will not result in: (1) maximum reactor vessel pressures greater than those obtained using the assumptions in Section 5.2.2 of the FSAR; or (2) a more limiting change in the MCPR than would be obtained with the assumptions used in Section 15.0. Provide the basis for the maximum reduction in feedwater heating considered in your response to this item (e.g., the specific limitations on the turbine operation).

Response:

There are two distinct periods of concern when operating with reduced feedwater temperature. Reducing the feedwater temperature before rated EOC will result in less severe transients. The peak pressures will be lower due to the reduced steam production. The CPRs will be smaller due to a stronger scram caused by additional insertion of the control rods to keep the reactor power within licensed limits and a less negative dynamic void coefficient.

Operating with reduced feedwater temperature after rated EOC is the other period of concern. The basis for the plant safety analysis does not cover this operating condition. Although it is expected that the original safety analysis will cover operation under a derated feedwater condition after EOC, an analysis is considered necessary to confirm this. Before operation in this condition is begun, the required analyses will be performed to ensure plant safety.

Q. 211.099
(7.5)

Since systems such as the HPCS, HPCI, and RCIC are initially aligned to draw coolant water from the CST and switch to the suppression pool following a signal indicating a low water level should be included in Table 7.5-1 of the FSAR, entitled "Safety-Related Display Instrumentation." Accordingly, add the signal indicating low water level in the CST in Table 7.5-1. Alternatively, justify its omission.

Response:

Level indication for the Condensate Storage Tank (CST) is provided in the Control Room. However, it is our position that the safety function of HPCS and RCIC is determined by displaying to the reactor operator pump discharge pressure and flow to the reactor, both of which are included in Table 7.5-1. Loss of level indication in the CST when HPCS or RCIC is operating will have no effect on the safe operation of the HPCS or RCIC systems because both systems switch their suctions from the CST to the suppression pool automatically following a signal indicating a low water level in the CST. The instrumentation effecting the switchover is Class 1E and an alarm is provided in the Control Room to indicate when switchover has occurred.

Q. 211.100
(7.5)

Identify which parameters are used to monitor the plant conditions following an accident and which are input to the safety-related display instrumentation shown in Table 7.5-1 of the FSAR.

Response:

The first half of this question basically asks for a description of WNP-2 compliance with Regulatory Guide 1.97. The regulatory guide is undergoing revision as a result of the Three Mile Island accident. WNP-2 site engineering is reviewing the various proposed draft revisions to the regulatory guide.

Since Revision 2 has yet to be issued, the Supply System can only make an educated guess as to what parameters and their requirements are to be defined in the regulatory guide.

WNP-2 has responded to the Regulatory Guide 1.97, Rev. 2 draft by providing comments and a general listing of variables and WNP-2 compliance with the draft revision. This information was submitted to the NRC staff via docket letter no. G02-80-29, dated February 1, 1980.

Following the issue of Regulatory Guide 1.97, Rev. 2, WNP-2 engineering will finalize the plant design in regard to monitoring the variables described in the regulatory guide. Because of the preliminary engineering already performed it is unlikely that the issue of Regulatory Guide 1.97, Rev. 2, will cause any appreciable additional redesign of the plant. Section 7.5 of the FSAR will be modified as required in light of the above. This FSAR revision will answer both parts of Question 211.100.

Q. 211.101
(7.5)

In Table 7.5-1 of the FSAR, you identify the range of the instrument which monitors the reactor vessel pressure to be from 0 to 1500 psig. Since the design pressure of the reactor coolant pressure boundary is 1250 psig, justify the upper bound of this instrument range in light of the potential transients and accidents that may cause large pressure excursions (i.e. ATWS).

Response:

The reactor pressure instrument range of 0 to 1500 psig is prudent for this device. This range envelopes the anticipated pressure transients while providing adequate resolution at mid-instrument range for normal operating conditions. The range also envelopes adequately postulated large pressure excursions due to potential transients and accidents (i.e. ATWS) since the maximum pressure encountered for any of these events is approximately 1250 psig for a short duration (usually less than 20 seconds). This conclusion is also true considering the turbine trip without bypass event.[1]

[1] NEDE-24222, "Assessment of BWR Mitigation of ATWS, Volume II," December 1979.

Q. 211.102
(7.4.1)

Provide display instrumentation indicating the water level in the CST on the remote shutdown control panel. You state in the FSAR that the RHR flow indicator will be located on the remote shutdown panel. Verify that flow indication will be provided for both RHR systems (i.e., A and B) and that the flow range will be the same as that shown in Table 7.5-1 of the FSAR.

Response:

Indication of CST water level on the remote shutdown panel is not necessary. Vessel inventory make-up requirements during a remote shutdown event are low and with a 135,000 gallon minimum CST inventory requirement, sufficient make-up capability exists for the length of time RCIC may be used.

The Remote Shutdown System is not required to meet single failure criteria. For this reason only the RHR B Loop controls exist on the remote shutdown panel. Flow indication for the B Loop is provided on this panel and the flow range is the same as that shown in Table 7.5-1, i.e., 0-10,000 gpm.

Q. 211.103
(9.2.7)

In Table 9.2-5 of the FSAR, you show a flow rate of 7400 gallons per minute (gpm) from the standby service water system to the RHR heat exchanger. This flow rate is based on an inlet temperature of 95^o Fahrenheit. However, in Section 5.4.7.2.2, the service water side flow rate of 7400 gpm to the RHR heat exchanger is based on a rated inlet temperature of 85^o Fahrenheit. Explain this apparent discrepancy. Additionally, demonstrate that you have adequately selected the required flow rates for the standby service water system for heat load removal from the ECCS pumps as shown in Table 9.2-5 of the FSAR. Provide justification for these flow rates, including a list of the design duty heat loads for the equipment identified in Table 9.2-5.

Response:

Section 5.4.7.2.2 is in error and is being revised to indicate an inlet SW temperature to the RHR heat exchangers of 95^o Fahrenheit. It should be noted that although the SW maximum design temperature is 85^o Fahrenheit, several components, including the diesel generators and portions of the ECCS systems as indicated in Table 9.2-5 were designed to 95^o Fahrenheit. This higher design temperature adds additional conservatism to the system. Also Table 9.2-5 has been revised to include the calculated and design duty heat loads for the standby service water cooled equipment. The standby service water flow rates for the ECCS pumps and all other equipment listed in Table 9.2-5 are the manufacturers' recommendations based on the standby service water temperature listed in Table 9.2-5. The flow rates for the RHR pump seals are set by the shutdown cooling mode which initially has a process fluid temperature of 358^{o}F.*

*Draft FSAR page changes attached.

[illegible]

5.4.7.2.2 Equipment and Component Description

a. System Main Pumps

The RHR main system pumps are motor-driven deep-well pumps with mechanical seals and cyclone separators. ~~The motors are water cooled~~. The pumps are sized on the basis of the LPCI mode (Mode A) and the minimum flow mode (Mode G) of the Process Data Figure 5.4-14b. Design pressure for the pump suction structure is 220 psig with a temperature range from 40°F to 360°F. Design pressure for the pump discharge structure is 500 psig. The bases for the design temperature and pressure are maximum shutdown cut-in pressures and temperature, minimum ambient temperature, and maximum shutoff head. The pump pressure vessel is carbon steel, the shaft is stainless steel. A comparison between the required NPSH (obtained from the pump characteristic curves provided in Figures 6.3-10a, b and c) and the NPSH needed in the Process Diagram Figure 5.4-14b (Note 8) demonstrates the required NPSH is adequate. Available NPSH is calculated per Regulatory Guide 1.1.

Delete

b. Heat Exchangers

The RHR system heat exchangers are sized on the basis of the duty for the shutdown cooling mode (Mode E of the Process Data). All other uses of these exchangers, including steam condensing, require less cooling surface.

Flow rates are 7450 gpm (rated) on the shell side and 7400 gpm (rated) on the tube side (service water side). Rated inlet temperature is ~~125°F shell side and 85~~°F tube side. The overall heat transfer coefficient is 195 BTU per hour square foot. The exchangers contain ~~7670~~ 7641 ft² of effective surface. Design temperature range of both shell and tube sides are 40°F to 480°F. Design pressure is 500 psig on both sides. Fouling factors are 0.0005 shell side and ~~0.0002~~ 0.002 tube side. The construction materials are carbon steel for the pressure vessel with stainless steel tubes and stainless steel clad tube sheet.

95 °F

5

TABLE 9.2-5

EQUIPMENT REQUIRING STANDBY SERVICE WATER TO ENSURE PLANT SHUTDOWN

	Equipment Cooled	Required Flow-gpm (1)	Design Heat Load (Btu/hr)	Calculated Heat Load (Btu/hr)
Division I				
1.	Standby Service Water Pumphouse "A" Cooler	80	404,000	380,600
2.	Diesel Generator "A"	1650 (2)	15,600,000	11,692,427
3.	Diesel Generator Building "A" Coolers	144	716,000	716,000
4.	LPCS Pump Motor Bearings	4 (3)	-	~ 0
5.	LPCS Pump Room Cooler	56	280,000	270,860
6.	RHR "A" Pump Seals	12 (2)	-	~ 0
7.	RHR "A" Room Cooler	33	165,000	149,650
8.	D.C. Motor Control Center Room Cooler	20	84,200	40,533
9.	Motor Control Center Room Cooler	15	71,280	43,130
10.	Control Room Cooler	120	285,000	256,500
11.	Cable Spreading Room Cooler	40	160,000	74,600
12.	Switchgear Room Cooler	60	370,000	327,100
13.	Hydrogen Recombiner "A" MCC Room Cooler	11	52,500	36,174
14.	Hydrogen Recombiner "A" Aftercooler	50	-	250,000
15.	Hydrogen Recombiner "A" Scrubber	10	-	50,000
16.	RHR "A" Heat Exchanger	7400 (2)	(4)	Variable
17.	Analyzer Room Cooler	10	42,500	23,571
	TOTAL	9715		

1) Based on 85°F Standby Service Water Supply unless otherwise noted.
2) Design based on 95°F Standby Service Water Supply
3) Design based on 90°F Standby Service Water Supply
4) See Table 6.2-2 for design parameters

TABLE 9.2-5 (Continued) Page 2 of 3

Equipment Cooled	Required Flow-gpm(1)	Design Heat Load (Btu/hr)	Calculated Heat Load (Btu/hr)
Division II			
1. Standby Service Water Pumphouse "B" Cooler	80	404,000	358,100
2. Diesel Generator "B"	1650 (2)	15,600,000	11,692,427
3. Diesel Generator Building "B" Coolers	144	716,000	716,000
4. Diesel Generator Area Cable Cooler (Corridor)	40	149,000	109,680
5. RHR "B" Pump Seals	12 (2)	-	~ 0
6. RHR "C" Pump Seals	12 (2)	-	~ 0
7. RHR "B" Room Cooler	33	165,000	145,650
8. RHR "C" Room Cooler	33	165,000	160,530
9. RCIC Pump Room Cooler	12	60,000	37,270
10. Motor Control Center Room Cooler	15	71,280	43,130
11. Control Room Cooler	120	285,000	256,500
12. Cable Spreading Room Cooler	40	160,000	74,600
13. Switchgear Room Cooler	60	320,000	305,400
14. Hydrogen Recombiner "B" Aftercooler	50	-	250,000
15. Hydrogen Recombiner "B" Scrubber	10	-	50,000
16. Hydrogen Recombiner "B" MCC Room Cooler	11	52,500	36,174
17. RHR "B" Heat Exchanger	7400 (2)	(3)	Variable
18. Analyzer Room Cooler	10	42,500	23,571
TOTAL	9732		

1) Based on 85°F Standby Service Water Supply unless otherwise noted.
2) Design based on 95°F Standby Service Water Supply
3) See Table 6.2-2 for design parameters

TABLE 9.2-5 (Continued) Page 3 of 3

Equipment Cooled	Required Flow-gpm(1)	Design Heat Load (Btu/hr)	Calculated Heat Load (Btu/hr)
Division III			
1. HPCS Diesel Generator	910 (2)	8,872,000	7,401,000
2. HPCS Diesel Building Coolers	144	716,000	716,000
3. HPCS Pump Room Cooler	50	500,000	473,580
TOTAL	1104		

1) Based on 85°F Standby Service Water Supply unless otherwise noted.
2) Design based on 95°F standby Service Water Supply

Q. 211.104
(9.2)

Provide a table listing the standby service water, system cooling duty loads as a function of the time intervals listed below following a postulated DBA. In this table, indicate the operating status of the appropriate safety-related equipment (e.g., the RHR pumps, the RHR heat exchangers, the CS pumps, the ADS valves, and the RCIC). The time intervals for this tabulation should be: (1) 0 to 10 minutes; (2) 10 to 30 minutes; (3) 30 minutes to 6 hours; (4) hours to 24 hours; and (5) 24 hours to 30 days.

Response:

Table 9.2-8, revised Table 9.2-9 and Figures 9.2-7b, 9.2-7c and 9.2-7d list all the loads to the service water system. Table 9.2-8 lists the heat rates and Table 9.2-9 lists the integrated heat loads.*

The ADS will automatically actuate unless reset by the control room operator at 120 seconds into a DBA. However, by 2 minutes into the accident, the vessel will already be fully depressurized (see Figure 6.3-21b for RPV pressure vs. time curve). The energy addition to the suppression pool by the ADS is accounted for in Tables 9.2-8 and 9.2-9.

The RCIC system does not operate following a DBA as discussed in note 32 of Table 6.2-16.

* draft FSAR page changes attached.

TABLE 9.2-9

INTEGRATED HEAT DATA - WNP-2 UHS RE-ANALYSIS

Time After LOCA Min.	Q Decay (1)	Q Sens (2)	Q Aux 1 (3)	Q Aux 2 (4)	Q Aux 3 (5)	Q Total (6)	Q SW (7)
	10^7 BTU						
0	0	0	0	0	0	0	0
1	3.51	.014	.020	.030	.015	3.59	.174
2	4.28	.027	.041	.061	.029	4.44	.355
4	5.57	.054	.083	.121	.058	5.89	.719
10	8.72	.136	.205	.303	.146	9.51	1.83
20	13.02	.271	.413	.606	.291	14.62	3.75
40	20.26	.543	.823	1.21	.582	23.45	7.80
90	35.16	1.22	1.85	2.73	1.31	42.32	18.69
120(2H)	43.03	1.63	2.48	3.64	1.75	52.57	25.57
240(4H)	70.65	3.26	4.94	7.27	3.49	89.66	54.51
360(6H)	94.84	4.88	7.41	10.91	5.24	123.3	84.37
480(8H)	117.0	6.51	9.88	14.54	6.98	155.0	114.3
720(12H)	157.6	9.77	12.08	21.92	6.98	208.4	172.4
960(16H)	194.9	13.02	14.27	29.39	6.98	258.6	227.3
1200(20H)	229.9	16.28	16.47	36.86	6.98	306.5	279.3
1440(1D)	263.1	19.54	18.66	44.45	6.98	352.8	328.6
2160(1-1/2D)	354.5	19.54	25.25	68.67	6.98	475.0	461.1
2880(2D)	435.3	19.54	31.84	94.64	6.98	588.3	581.1
4320(3D)	577.2	19.54	45.02	148.2	6.98	796.9	796.6
5760(4D)	702.3	19.54	58.19	201.7	6.98	988.8	995.4
7200(5D)	816.2	19.54	71.37	255.3	6.98	1169	1182
8640(6D)	922.0	19.54	84.54	308.8	6.98	1342	1358
11520(8D)	1116	19.54	110.9	415.9	6.98	1669	1689
14400(10D)	1292	19.54	137.2	523.0	6.98	1979	2001
17280(12D)	1456	19.54	163.6	630.1	6.98	2276	2300
23040(16D)	1756	19.54	216.3	844.2	6.98	2843	2870
28800(20D)	2029	19.54	269.0	1058	6.98	3383	3412
34560(24D)	2282	19.54	321.7	1273	6.98	3903	3935
43200(30D)	2635	19.54	400.8	1594	6.98	4656	4689

TABLE 9.2-9 (Continued)

NOTES:

(1)	Q Decay	Integrated core decay heat rejected to suppression pool.
(2)	Q Sensible	Integrated sensible heat rejected by the reactor vessel, piping, and core to the suppression pool.
(3)	Q Auxiliary 1	Integrated heat from ECCS pump work rejected to the suppression pool.
(4)	Q Auxiliary 2	Integrated heat from auxiliary systems rejected to Division 1 service water system. This heat includes all sources of heat into Division 1 SW system except for the RHR heat exchanger. The RHR heat exchanger transfers heat from the suppression pool to Division 1 SW system.
(5)	Q Auxiliary 3	Integrated heat from HPCS service water system. This heat is a straight heat dump into spray pond A.
(6)	Q Total	Sum of Q Decay, Q Sensible, Q Auxiliary 1, Q Auxiliary 2, and Q Auxiliary 3.
(7)	Q Service Water	Sum of Q Auxiliary 2 and the heat rejected by the RHR heat exchanger into Division 1 service water system, i.e., the sum of the heat rejected through the spray nozzles.

(8) The RHR heat exchangers provide suppression pool cooling ~~after~~ from 10 minutes through to the end of ~~the~~ an accident (30 days). No heat exchanger cooling is assumed for the first 10 minutes of an accident. See section 6.2.2.2 & 6.3.2.8 for further information on containment cooling.

Q. 211.105
(3.9.1)

Provide the following information related to the contents of Table 3.9-1 of the FSAR. This table shows the number of plant cycles or events considered for the reactor assembly design and fatigue analysis.

a. Discuss the events contained in Item i for normal, upset and testing conditions and relate these to the transients analyzed in Section 15.0 of the FSAR. In particular, discuss the following events:

(1) The number of cycles (i.e., eight cycles) for the 40 year life of the WNP-2 facility shown in Table 3.9-1 of the FSAR (i.e., Item i.4) for a single safety or relief valve blowdown for upset conditions, appears to be low. Specifically, we note that Table 15.0 of the FSAR indicates that these valves will lift for a variety of transient events and that more than one valve will blow down. Accordingly, provide justification for your design basis of eight cycles.

(2) Clarify whether the loss of feedwater pumps in Item i.3 is due to MSIV closure or whether both of these events occur independently. For either case, the number of cycles (i.e., ten cycles) which you state for the 40-year life of the WNP-2 facility, appears to be low. In particular, since a number of transients can cause a trip of the feedwater pumps and close the MSIVs, more than ten events causing the above conditions can be anticipated throughout the plant lifetime. Accordingly, justify your design basis of ten cycles for this event.

b. Indicate whether Item 1(2) for emergency conditions in Table 3.9-1 of the FSAR is the automatic blowdown feature related to the ADS function.

c. Explain Item 1(2) for emergency conditions and relate it to your analysis in Sections 5.2.2 or 15.0 of the FSAR. Justify your omission of the event in which the reactor is overpressurized, there is a scram initiated by a high flux signal and the isolation valves stay closed under "emergency conditions."

Response:

a. The scram events listed occur from various causes as follows:

Turbine Generator Trip, Feedwater On, Isolation Valves Stay Open - 40 Cycles

These events correspond to the "Generator Load Rejection - Turbine Control Valve (TCV) Fast Closure" and "Turbine Trip" described in Chapter 15 without other failures assumed, such as bypass failure. The same condition with bypass failure is included with the "Loss of Feedwater Pump" scram events.

Loss of Feedwater Pumps, Isolation Valves Closed - 10 Cycles

These are composite events which assume "Generator Load Rejection With Bypass Valve Failure" or "Main Steam Isolation Valve Closure", coupled with a "Loss of Auxiliary Power" which are all described in Chapter 15.

Single Safety or Relief Valve Blowdown - 8 Cycles

These are complete reactor depressurization cycles due to the failure of safety, relief, or turbine bypass valve to reclose automatically after pressure has dropped below its design setting.

1. The specified 8 valve blowdowns are based on reliability studies which considered the failure rates of such valves to close as intended after actuation, and the number of valves, and the expected number of valve actuations. The valve lifts in Table 15.0 include the larger number of actuations which are expected to occur where the valves function normally without completely depressurizing the reactor.

2. As noted in the "Loss of Feedwater Pump, Isolation Valve Closed" event described above, the simultaneous occurrence of feedwater pump trip is but one effect of loss of auxiliary power and reactor isolation. The effects of feedwater pump trip are included, where appropriate, in all other scram situations. Feedwater pump trip may also cause a scram due to low water level, which is included in the "Other Scram" category.

b. Item 1.(2) ~~a.2~~ is related to the ADS function. It assumes a complete reactor depressurization due to unintended operation of the ADS system or an assumed failure of several safety or relief valves to reclose automatically at their reset pressure.

c. The "Reactor Overpressure With Delayed Scram" event assumes closure of main turbine admission valves assuming that scram is delayed so that power and pressure are initially limited by safety valve operation and reactor recirculation pump tripoff. A similar condition is discussed under the study of the "Anticipated Transient Without Scram (ATWS)" event in Chapter 15. This delayed scram event results in more severe pressure and power transient conditions than a "Flux Scram With Isolation Valve Closure" which is conservatively considered to be an "Upset Condition" covered under the "Loss of Feed Pump, Isolation Valves Closed" event discussed under a. above.

Q. 211.106
(15.0)

Provide the correct units (or value) for the recirculation pump trip inertia for Item 32 of Table 15.0-2 of the FSAR.

Response:

Table 15.0-2 has been modified.*

*Draft FSAR page change attached.

TABLE 15.0-2 - (Continued)

28.	High Pressure Scram Set Point, psig	1071
29.	Vessel Level Trips, Feet Above Separator Skirt Bottom	
	Level 8 - (L8), feet	5.750
	Level 4 - (L4), feet	3.750
	Level 3 - (L3), feet	2.167
	Level 2 - (L2), feet	(-) 2.041
30.	APRM Thermal Trip Set Point, % NBR @ 100% core flow	122.03
31.	Recirculation Pump Trip Delay, Seconds	0.140
32.	Recirculation Pump Trip Inertia ~~for Analysis, lb./ft2*~~ time constant for analysis, seconds*	~~24,500~~ 6

* The inertia time constant is defined by the expression:

$$t = \frac{2 \pi J_o n}{g T_o}$$, where

t = inertia time constant (Sec).
J_o = pump motor inertia (lb-ft^2)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (lb-ft)

NOTES:

1. BASE MAP FROM U.S.G.S. TOPOGRAPHIC 7½ MINUTE QUADRANGLE SHEETS OF NINE CANYON, WALLULA, ZANGAR JUNCTION, TOUCHET AND LOWDEN, WASHINGTON, AND RING, SMELTZ AND WATERMAN, OREGON.
2. BEDROCK GEOLOGY COMPILED FROM WPPSS (1977 a & b) SWANSON, ET AL. (1977), NEWCOMB (1965) AND THIS STUDY
3. IDENTIFICATION AND MAPPING OF THE BASALT STRATIGRAPHY EAST OF VANSYCLE CANYON IS PRELIMINARY AND TENTATIVE.

GEOLOGIC UNITS

QUATERNARY

Qal
Alluvial sand and gravel

Ql
Loess
Light brown, windblown silt of variable ages

Qt
Touchet beds of the Glaciofluvial deposits. Light gray and brown, bedded silt with a network of clastic dikes, Locally includes channel sand and gravel, and reworked colluvium along narrow canyons (13,000 ybp)

Ql-Qt
Undifferentiated silt.
Includes windblown and Touchet silt.

Qg
Pasco gravel of the Glaciofluvial deposits.

Qc
Angular basalt fragments of varying sizes intermixed with silt mantling steep slopes; underlain by basalt flows at shallow depth. (Not mapped as a separate unit in order to show the basalt stratigraphy)

TERTIARY
MIOCENE
YAKIMA BASALT SUBGROUND

Ti	Te	Tw	Tem	Tp	Tu

Saddle Mountains Basalt
Ti, Ice Harbor Member (8.5 mybp)
Te, Tuff of the Ellensburg Fm.
Tw, Ward Gap Member
Tem, Elephant Mountain Member (10.5 mybp)
Tp, Pomona Member (12.5 mybp)
Tu, Umatilla Member

Tf
Wanapum Basalt
Frenchman Springs Member

Tgr
Grande Ronde Basalt
(14.0-16.5 mybp)

LEGEND

- TECTONIC BRECCIA OF THE WALLULA FAULT ZONE.—OUTCROP AREAS.
- OUTCROPS OF ASH DEPOSITS
- LOCATION OF ERRATICS ABOVE ELEVATION 1000 FEET
- QF — LOCATION OF A PROBABLE QUATERNARY FAULT
- 5 — STRIKE AND DIP OF BASALT FLOWS
- STEEPLY DIPPING FLOWS (DIPS GREATER THAN 75)
- OBLIQUE SLIP FAULTS WITH BALL ON DOWNTHROWN BLOCK; DOTTED WHERE CONCEALED; ARROW INDICATES SENSE OF MOTION
- ANTICLINE, WITH DIRECTION OF OF PLUNGE INDICATED
- SYNCLINE
- LOCATION OF THE PHOTO-LINEAR (GROUND-SURFACE RUPTURE OF BINGHAM, AND OTHERS 1970)
- A A′ — LOCATION OF GEOLOGIC CROSS-SECTION A-A′
- SHEAR ZONE
- A — LOCALLITY DESIGNATION (REF. SECTION 3.1.1)

0 2000 4000
SCALE IN FEET
CONTOUR INTERVAL 20 FEET

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NOS. 1 & 4

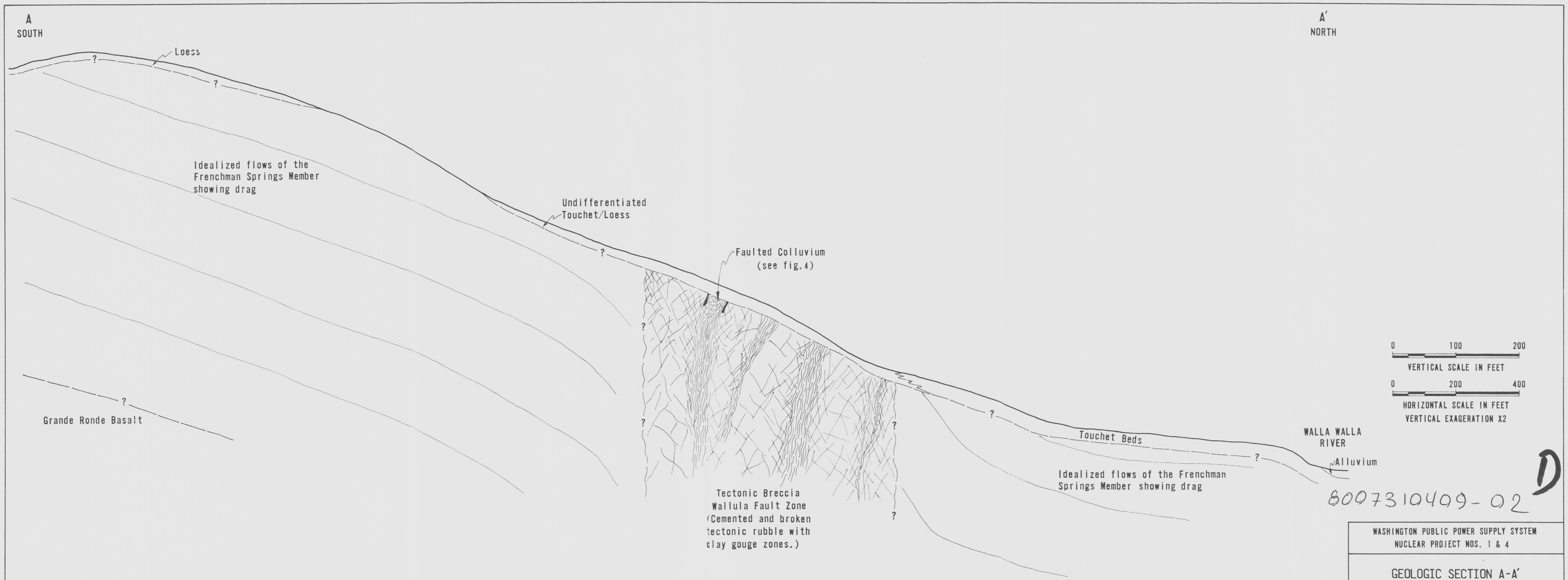
GEOLOGIC MAP
WARM SPRINGS CANYON AREA
SOUTHEASTERN WASHINGTON

DECEMBER, 1979 UE & C CONTRACT # 44013

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG. 2

8007310409-01 E



D

8007310409-02

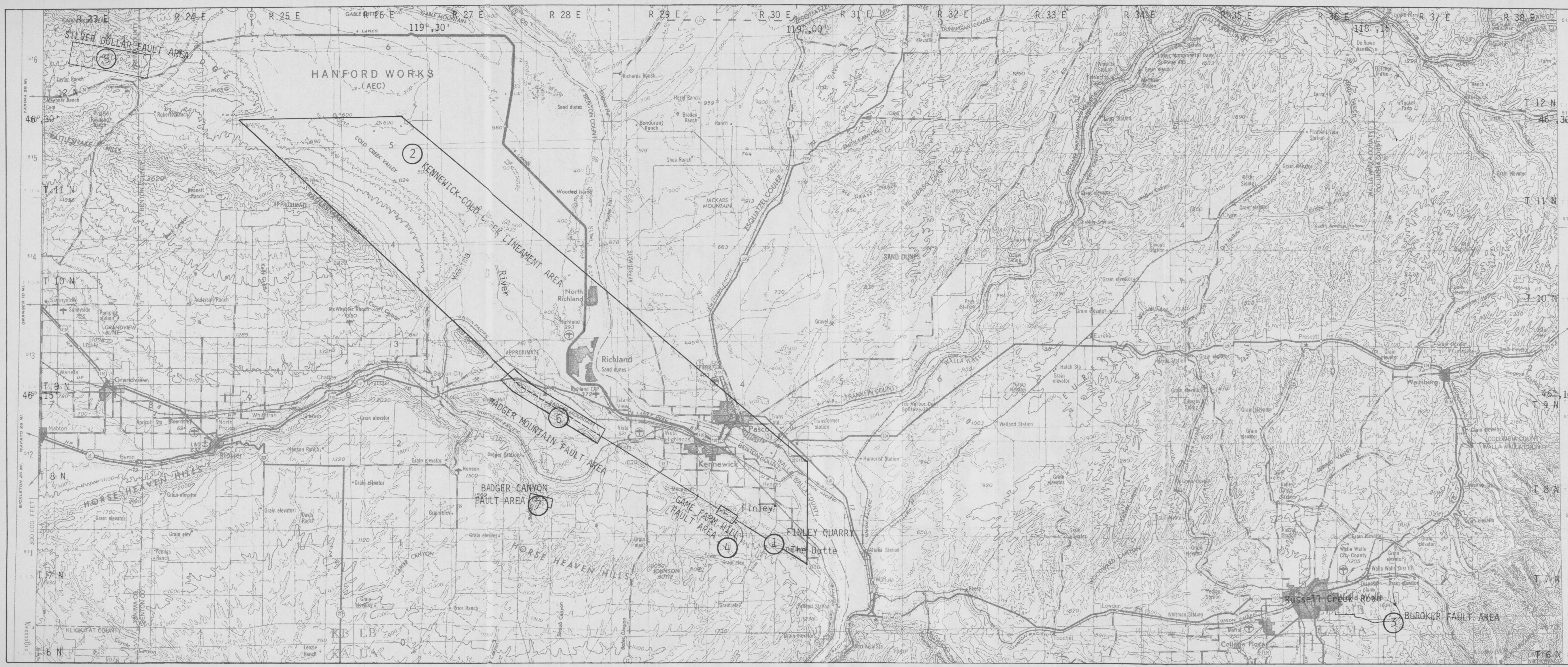
WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NOS. 1 & 4

GEOLOGIC SECTION A-A′
WALLULA FAULT ZONE

DECEMBER 1979 UE & C CONTRACT # 44013

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
PORTLAND, OREGON

FIG. 3



EXPLANATIONS

1. FINLEY QUARRY; see Section 2 and Figs. 2 thru 6.
2. KENNEWICK-COLD CREEK LINEAMENT; see Section 3 and Figs. 7 thru 9.
3. BUROKER FAULT; see Section 4 and Figs. 10 thru 12.
4. GAME FARM HILL FAULT; see Section 5.
5. SILVER DOLLAR FAULT; see Section 6.
6. BADGER MOUNTAIN FAULT; see Section 7.
7. BADGER CANYON FAULT; see Section 8.

SCALE 1:250,000

0 5 10 Miles

0 5 10 Kilometers

N

BASE MAP TAKEN FROM AMS QUADRANGLE OF WALLA WALLA

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NOS. 1 & 4

INDEX AND LOCATION MAP

MAY, 1980 UE & C CONTRACT # 44013

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Portland, Oregon

FIG. 1

8007310409-03 D

GEOLOGIC UNITS

UNIT 1 Loess

UNIT 2 Colluvium
2a Young
2b Old

UNIT 3 Fault Breccia Zone
3a Gouge
3b Gouge
3c Tuff
3d Breccia
3e Gouge
3f Breccia
3g Shear

UNIT 4 Umatilla Basalt

SEE SECTION 2 FOR DETAILED DESCRIPTIONS OF LITHOLOGIC UNITS.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NULCEAR PROJECT.NOS.1 & 4

GEOLOGIC SKETCH
OF FINLEY QUARRY FAULT

MAY, 1980 UE & C CONTRACT # 44013

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Portland, Oregon

FIG.2

8007310409-04 E

LEGEND:

DEFINITION OF LINEAMENT ON LANDSAT PHOTOGRAPH

DEFINITION OF LINEAMENT ON AMS SHEET

DEFINITION OF LINEAMENT ON 7.5' AND 15' TOPOGRAPHIC MAPS AND ON LOW ALTITUDE AERIAL PHOTOGRAPHS. (DASHED WHERE LESS DISTINCT)

SCALE 1:62500

0 1 2 3 4 Miles

0 1 2 3 4 Kilometers

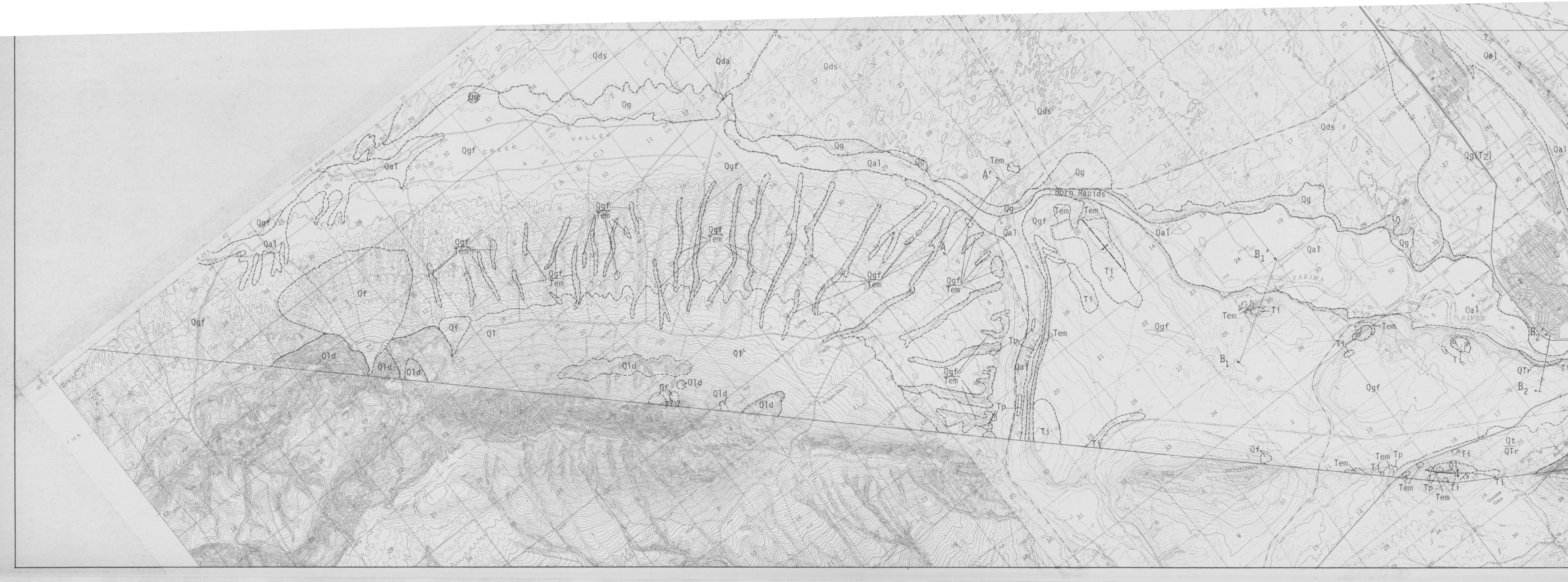
CONTOUR INTERVAL 20'

BASE MAP TAKEN FROM U.S.G.S. 15' TOPOGRAPHIC QUADRANGLES OF RICHLAND, BADGER MOUNTAIN, ELTOPIA, PASCO AND CORRAL CANYON.

LINEAMENTS FROM WPPSS (1977) AND THIS INVESTIGATION

WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NOS. 1 & 4	
LINEAMENT MAP	
MAY, 1980 UE & C CONTRACT # 44013	
SHANNON & WILSON, INC. Geotechnical Consultants Portland, Oregon	FIG. 7

8007310409 -05 E



35° STRIKE AND DIP

U FAULT WITH VERTICAL DISPLACEMENT, U ON UPTHROWN SIDE

AXIS OF FOLD. DASHED WHERE APPROXIMATE, DOTTED WHERE CONCEALED

A A' LOCATION OF GEOLOGIC CROSS-SECTIONS

SHEAR ZONE

SCALE 1:62,500

0 1 2 3 4 Miles

0 1 2 3 4 Kilometers

CONTOUR INTERVAL 20'

BASE MAP TAKEN FROM U.S.G.S. 15' TOPOGRAPHIC QUADRANGLES OF RICHLAND, BADGER MOUNTAIN, ELTOPIA, PASCO AND CORRAL CANYON.
COMPILATION FROM WPPSS (1977a), ROCKWELL (1979a), AND THIS INVESTIGATION

QUATERNARY

Qal — Alluvial sand and gravel

Qf — Alluvial fan deposits

Qda — Active dunes

Qds — Stabilized dunes

Qld — Landslide debris

Ql — Loess
Light brown, wind-blown silt of various ages.

Qt — Touchet beds of the Glaciofluvial deposits
Light gray and brown, bedded silt with a network of clastic dikes. Locally includes channel sand and gravel, and reworked colluvium along narrow canyons (13,000 ybp).

Qg — Pasco gravel of the Glaciofluvial deposits

TERRACES
APPROXIMATE ELEVATIONS

T_4 - 600'
T_3 - 500'
T_2 - 370'
T_1 - 340'

Qgf — Glaciofluvial deposits undifferentiated

Qkf — Kennewick fanglomerate

TERTIARY
MIOCENE-PLIOCENE

QTr — Ringold Formation undifferentiated

Ti	Tw	Tem	Tp	Tu

Saddle Mountains Basalt of the Yakima Basalt Subgroup

Ti, Ice Harbor Member (8.5 mybp)
Tw, Ward Gap Member
Tem, Elephant Mountain Member (10.5 mybp)
Tp, Pomona Member (12.5 mybp)
Tu, Umatilla Member

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT NOS. 1 & 4

GEOLOGIC MAP
OF KENNEWICK-COLD CREEK
LINEAMENT AREA

MAY, 1980 UE & C CONTRACT # 44013

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Portland, Oregon

FIG. 8