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August 17, 1982

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

Attention: Ms. E. G. Adensam, Chief
Licensing Branch No. 4

Re: Catawba Nuclear Station
Docket Nos. 50-413 and 50-414

Dear Mr. Denton:

As a result of a meeting with the Reactor Systems Branch on June 28 and 29, 1982, Duke Power Company is transmitting herewith responses, revised responses, or partial responses to the following FSAR questions:

440.20	440.113	440.122	440.T.6
440.29	440.116	440.123	440.T.7
440.30	440.117	440.124	440.T.8
440.52	440.118	440.125	440.T.9
440.56	440.119	440.127	
440.107	440.120	440.128	
440.108	440.121	440.129	

These responses will be included in FSAR Revision 6.

Very truly yours,

H B Tucker /jb

H. B. Tucker, Vice President
Nuclear Production Department

ROS/php
Attachment

cc: Mr. James P. O'Reilly, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, Suite 3100
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Mr. P. K. Van Doorn
NRC Resident Inspector
Catawba Nuclear Station

B001

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Mr. Henry A. Presler, Chairman
Charlotte-Mecklenburg Environmental Coalition
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Mr. Darrell Monnie
c/o Mr. R. E. Lyon
EG&G, Idaho
Reliability and Statistics Division
1520 Sawtelle Street
P.O. Box 1625
Idaho Falls, Idaho 83401

Response to TMI Concerns

The Catawba Work Request Program governs all maintenance activities performed at Catawba. These work requests describe the maintenance to be performed and the procedures for performing it. Upon completion of the maintenance all work requests are entered into the corporate computer. This program provides for portable historical records of all maintenance performed on safety-related systems.

C.1.17

The design of Catawba Nuclear Station does not feature safety injection initiation on coincident pressurizer level and pressure signals. Safety injection is initiated whenever the low pressurizer pressure trip setpoint is reached independent of pressurizer level (See Section 7.3).

II.K.2 COMMISSION ORDERS ON B&W PLANTS

II.K.2.13 THERMAL MECHANICAL REPORT - EFFECT OF HIGH-PRESSURE INJECTION ON VESSEL INTEGRITY FOR SMALL-BREAK LOSS-OF-COOLANT ACCIDENT WITH NO AUXILIARY FEEDWATER

WCAP-10019 which addresses the NRC requirements of detailed analysis of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater was submitted to the NRC on December 30, 1981 (OG-66). This WCAP was developed under the sponorship of the Westinghouse Owners Group (WOG). On March 23, 1982 WOG letter OG-68
Q440.T.8 was submitted to the NRC which described the additional effort underway to resolve NRC comments and questions concerning WCAP-10019. Results of the program to date show that operating plants can withstand the limiting transients for the expected life of their vessels. Since WCAP-10019 only addresses operating plants, an additional effort is underway to address NTOL plants. This report should be available in early 1983.

II.K.2.17 POTENTIAL FOR VOIDING IN THE REACTOR COOLANT SYSTEM DURING TRANSIENTS

Westinghouse (in support of the Westinghouse Owners Group) has performed a study which addresses the potential for void formation in Westinghouse designed nuclear steam supply systems during natural circulation cooldown/depressurization transients. This study has been submitted to the NRC by the Westinghouse Owners Group (Letter OG-57, dated April 20, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to P.S. Check (NRC)) and is applicable to Catawba Nuclear Station.

Q440.T.2

In addition, the Westinghouse Owners Group has developed a natural circulation cooldown guideline that takes the results of the study into account so as to preclude void formation in the upper head region during natural circulation cooldown/depressurization transients, and specifies those conditions under which upper head voiding can occur. These Westinghouse Owners Group generic guidelines have been submitted to the NRC (Letter OG-64, dated November 30, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to D. G. Eisenhut (NRC)). The generic guidance developed by the Westinghouse Owners Group (augmented as appropriate with plant specific considerations) will be utilized in the implementation of Catawba plant specific operating procedures.

Response to TMI Concerns

II.K.3.10 PROPOSED ANTICIPATORY TRIP MODIFICATION

See Section 7.2.

II.K.3.11 JUSTIFICATION FOR USE OF CERTAIN PORV'S

See II.D.1

II.K.3.12 CONFIRM EXISTENCE OF ANTICIPATORY REACTOR TRIP UPON TURBINE TRIP

See Section 7.2

II.K.3.17 REPORT ON OUTAGES OF EMERGENCY CORE-COOLING SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

Q440.T.6 Duke will develop and implement a plan to compilate ECC systems or components involved in outages. The plan will require a periodic report which contains (1) ECC system or components involved, (2) outage dates and duration of outages, (3) cause of the outage, and (4) corrective action taken. Q440.T.9 Test and maintenance outages will be included. The report will be reviewed and changes proposed to improve the availability of ECC equipment, if needed. This plan will be developed prior to fuel load.

II.K.3.25 EFFECTS OF LOSS OF ALTERNATING-CURRENT POWER ON PUMP SEALS

At the Catawba Nuclear Station the reactor coolant pump seal water is supplied by the charging pumps and cooled by component cooling water. Nuclear service water in turn cools the component cooling water. In the event of a loss of offsite power, the component cooling water pumps, the nuclear service water pumps, and the charging pumps are all supplied with emergency power from the emergency diesel generators.

II.K.3.30 REVISED SMALL-BREAK LOSS-OF-COOLANT-ACCIDENT METHODS TO SHOW COMPLIANCE WITH 10 CFR PART 50, APPENDIX K

This item requires that the analysis methods used by NSSS vendors and/or fuel suppliers for small-break LOCA analysis for compliance with Appendix K to 10 CFR Part 50 be revised, documented, and submitted for NRC approval.

Westinghouse feels very strongly and Duke agrees that the small-break LOCA analysis model currently approved by the NRC for use on Catawba is conservative and in conformance with Appendix K to 10 CFR Part 50. However, (as documented in Letter OG-60, dated June 15, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to P. S. Check (NRC), Westinghouse believes that improvement in the realism of small-break calculations is a worthwhile effort and has committed to revise its small-break LOCA analysis model to address. NRC concerns (e.g., NUREG-0611, NUREG-0623, etc.). This revised

performance. Redundant sources of the ECCS actuation signal are available so that the proper and timely operation of the ECCS will not be inhibited. Sufficient instrumentation is available so that a failure of an instrument will not impair readiness of the system. The active components of the ECCS are powered from separate buses which are energized from offsite power supplies.

In addition, redundant sources of auxiliary onsite power are available through the use of the emergency diesel generators to assure adequate power for all ECCS requirements. Each diesel is capable of driving all pumps, valves and necessary instruments associated with one train of the ECCS.

Spurious movement of a motor operated valve due to the actuation of its positioning device coincident with a LOCA has been analyzed and found not credible for consideration.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long term recirculation operations.

Environmental testing of ECCS equipment inside the containment, which is required to operate following a loss of coolant accident, is discussed in Section 3.11.

6.3.2 SYSTEM DESIGN

The Emergency Core Cooling System (ECCS) components are designed such that a minimum of three low pressure cold leg accumulators, the high pressure (UHI) accumulators, one charging pump, one safety injection pump, and one residual heat removal pump together with their associated valves and piping will assure adequate core cooling in the event of a design basis loss of coolant accident. The redundant onsite emergency diesels assure adequate emergency power to all electrically operated components in the event that a loss of offsite power occurs simultaneously with a loss of coolant accident, assuming a single failure in the emergency power system such as the failure of one diesel to start.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Flow diagrams of the ECCS are shown in Figures 6.3.2-1 through 6.3.2-5.

Process flow diagram Figure 6.3.2-9 (sheets 1 and 2) shows the flow rate thru the ECCS under injection, cold-leg recirculation, and hot-leg recirculation operating modes.

A complete listing of ECCS valve interlocks is presented in Table 6.3.2-3.

Q440.108 A description of the automatic features and interlocks used in different modes of system operation are listed below.

1. The safety injection ("S") signal is received by the following equipment in the ECCS to initiate cold leg injection (for a complete listing of pumps and valves that receive an "S" signal see Table 3.9.3-13 and Table 3.9.3-14):

Table 6.3.2-3 (Page 1)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
Cold Leg Accumulator Isolation Valves	1NI54A 1NI65B 1NI76A 1NI88B	None	Opens (if closed) on S. Opens (if closed) on NC pressure greater than P-11. Power to valve operator removed during plant normal power operation	on MCB	Yes-Out of Position
NI Pump Suction from FWST	1NI100B 1NI103A 1NI125B	None	None. Power to valve 1NI100B operator removed during plant normal power operation	MCB	Yes-Out of Position
ND Suction from FWST	1FW27A (1FW55B)	Cannot be opened unless the following are closed. Sump valve 1NI185A (1NI184B), auxiliary spray valve 1NS43A (1NS38B), ND discharge to CCP (NI Pump) suction valve 1ND28A (1NI136B) and NS pump suction from containment sump valve 1NS18A (1NS1B).	Valve closes when valve 1NI185A (1NI184B) reaches its full open position.	MCB	Yes-Out of Position
ND Pump Discharge to CCP (NI Pump) Suction	1ND28A (1FW55B)	Cannot be opened unless NI pump miniflow isolated (valves 1NI115 and 1NI144A, or 1NI147B closed) ND to NC	None	MCB	Yes-Out of Position

Table 6.3.2-3 (Page 2)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
		isolated [1ND1B or 1ND2A closed (1ND36B or 1ND37A)] and sump isolation valve open 1NI185A (1ND184B)			
NI Pump Hot Leg Discharge Header	1NI121A 1NI152B	None	None	MCB	Yes-Out of Position
ND Hot Leg Discharge Header	1NI183B	None	None	MCB	Yes-Out of Position
Containment Sump Isolation Valve	1NI184B (1NI185A)	Cannot be opened unless ND to NC isolated, 1ND36B or 1ND37A (1ND1B or 1ND2A) closed and FWST outlet valve 1FW55B (1FW27A) closed.	Opens on FWST Low With S Signal (This bypasses the interlocks associated with control room push-button)	MCB	Yes-Out of Position
CCP Suction from RWST	1NV252A 1NV253B	None	Opens on S	MCB	Yes-Out of Position
CCP Normal Suction	1NV188A 1NV189B	None	Closes on S if CCP Suction from FWST valves open	MCB	Yes-Out of Position
NI Pump to C.L.	1NI162A	None	None	MCB	Yes-Out of Position

Q440.108

Table 6.3.2-3 (Page 3)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
CCP Normal Discharge	1NV312A 1NV314B	None	Closes on S	MCB	None
BIT Suction	1NI4A 1NI5B	None	Opens on S	MCB	Yes-Out of Position
BIT Discharge	1NI9A 1NI10B	None	Opens on S	MCB	Yes-Out of Position
CCP/NI Pump Suctions Cross-over	1NI332A 1NI333B 1NI334B	None	None	MCB	Yes-Out of Position
NC to ND Isolation Valves	1ND1B and 1ND2A (1ND36B and 1ND37A)	Can be opened only if the following valves are closed: ND suction from FWST 1FW27A (1FW55B), containment sump isolation valve 1NI185A (1NI184B), ND Pump discharge to CCP (NI Pump) suction valve 1ND28A (1NI136B), and the residual containment spray valve 1NS43A (1NS38B). Also, NC pressure must be below setpoint.	Valves close automatically (if open) when NC pressure exceeds setpoint.	MCB	None
ND to NC Cold Legs	1NI173A 1NI178B	None	None	MCB	Yes-Out of Position

Table 6.3.2-3 (Page 4)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
NI Pump Miniflow	1NI115A 1NI144A 1NI147B	To open any of these valves the following must be closed: ND discharge to CCP valve 1ND28A and ND discharge to NI Pump valve 1NI136B.	None Valve 1NI147B has power removed from operator during plant normal power operation.	MCB MCB	Yes-Out of Position Yes-Out of Position
ND Cross Connect	1ND32A 1ND65B	None		MCB	Yes-Out of Position
NI Pump Cross Connect	1NI118A	None		MCB	Yes-Out of Position
CCP Miniflow	1NV202B 1NV203A	None	None	MCB	Yes-Out of Position
NS Suction from FWST	1NS20A (1NS3B)	Cannot be Opened Unless NS Suction from Sump valve 1NS18A (1NS1B) is closed.	None	MCB	Yes-Out of Position
NS Suction from Sump	1NS18A (1NS1B)	Cannot be Opened Unless NS suction from FWST valve 1ND20A (1NS3B) closed and sump isolation valve 1NI185A (1NI184B) open.	None	MCB	Yes-Out of Position
Residual Containment Spray	1NS43A (1NS38B)	Cannot be opened unless ND to NC isolation valve 1ND1B or 1ND2A (1ND36B or	Valve closes automatically (if open) on disable signal	MCB	Yes-Out of Position

Table 6.3.2-3 (Page 5)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
		1ND37A) is closed and Containment Sump Isolation valve 1NI185A (1NI184B) is open and an enable signal is generated by the Containment Pressure Control System.	from the Containment Pressure Control System		

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
32.	Residual heat removal pump A (Pump B analogous)	Fails to deliver working fluid.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant from the Containment Sump to the hot legs of RC loops. Fluid flow from RHR pump A will be lost. Minimum flow requirements to hot legs of RC loop will be met by RHR pump B recirculating fluid to RC hot legs via SI pumps.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	
33.	Hydraulic cylinder operated gate valve 1NI242B (1NI243A analogous)	Fails to close on demand.	Injection - upper head of pressure vessel.	Failure reduces the redundancy of isolation valves provided for UHI accumulator tank discharge line "A" to block flow of N^2 from the tank to the UHI nozzles of the RV after the injection of water to the RV. No effect on safety for system operation. Alternate isolation valve (1NI243A) in the tank discharge line closes to provide backup isolation against the flow of N^2 to the RV.	Valve position (UHI valve full closed) monitor light for group monitoring of components (containment isolation) at MCB. Valve position indication (open to closed position change) at HSP. Gag motor position indication (not gagged to gagged position change) at HSP. UHI valve hydraulic system trouble alarm at MCB.	Valve is electrically interlocked with the instrumentation that monitors fluid level (1NILS5720) of the UHI accumulator tank. Valve is energized to close upon actuation by a low water level signal. Alarm is generated if valve is closed and RCS pressure is above the "SI" unblock valve.
34.	Hydraulic cylinder operated gate valve 1NI244B (1NI245A analogous)	Fails to close on demand.	Injection - upper head of pressure vessel.	Same effect on system operation as that stated above for item #33 except applies to to UHI accumulator tank discharge line "B".	Same methods of detection as those stated above for item #33.	Same remark as that stated above for item #33 except fluid level instrumentation 1NILS5730 actuates valve to close.

Q440.108

TABLE 15.0.3-2 (Page 1)

Summary of Initial Conditions and Computer Codes Used

	Faults	Computer Codes Utilized	Reactivity Coefficients[a] Assumed Moderator Temperature (Δk/°F)	Reactivity Coefficients[a] Assumed Moderator Density (Δk/gm/cc)	Doppler	Improved Thermal Design Procedure	Initial NSSS Thermal Power Output Assumed (MWt)
15.1	Increase in Heat Removal by the Secondary System						
	Feedwater system malfunctions that result in an increase in feedwater flow	LOFTRAN	-	0.43	lower[a]	Yes	0 and 3427
	Excessive increase in secondary steam flow	LOFTRAN	-	Figure 15.0.3-2 and 0.43	lower[a]	Yes	3427
	Inadvertent opening of a steam generator relief or safety valve	LOFTRAN	-	Function of moderator density (see Section 15.1.4, Figure 15.1.4-1)	-2.2 pcm/SF	No	0 (Subcritical)
	Steam system piping failure	LOFTRAN, THINK	-	Function of moderator density (see Section 15.1.5, Figure 15.1.4-1)	See Section 15.1.5	NA	0 (Subcritical)

a. See Figure 15.0.4-1

TABLE 15.0.3-2 (Page 2)

	Faults	Computer Codes Utilized	Reactivity Coefficients[a] Assumed Moderator Temperature (Δk/°F)	Moderator Density (Δk/gm/cc)	Doppler	Improved Thermal Design Procedure	Initial NSSS Thermal Power Output Assumed (MWt)
15.2	Decrease in Heat Removal by the Secondary System						
	Loss of external electrical load and/or turbine trip	LOFTRAN	-	Figure 15.0.3-2 and 0.43	upper and lower[a]	Yes	3427
	Loss of nonemergency AC power to the station auxiliaries	LOFTRAN	-	Figure 15.0.3-2	upper[a]	NA	3581
	Loss of normal feedwater flow	LOFTRAN	-	Figure 15.0.3-2	upper[a]	NA	3581
	Feedwater system pipe break	LOFTRAN		Figure 15.0.3-2	upper[a]	NA	3581
15.3	Decrease in Reactor Coolant System Flow Rate						
	Partial and complete loss of forced reactor coolant flow	LOFTRAN, FACTRAN, THINC	-	Figure 15 0.3-2	upper[a]	Yes	3427 and 2399
	Reactor coolant pump shaft seizure (locked rotor)	LOFTRAN, FACTRAN	-	Figure 15.0.3-2	upper[a]	No	3477 and 2399

TABLE 15.0.3-2 (Page 3)

	Faults	Computer Codes Utilized	Reactivity Coefficients[a] Assumed Moderator Temperature ($\Delta k/^{o}F$)	Reactivity Coefficients[a] Assumed Moderator Density ($\Delta k/gm/cc$)	Doppler	Improved Thermal Design Procedure	Initial NSSS Thermal Power Output Assumed (MWt)
15.4	Reactivity and Power Distribution Anomalies						
	Uncontrolled rod cluster control assembly bank withdrawal from a sub-critical or low power startup condition	TWINKLE, FACTRAN, THINC	Refer to Section 15.4.1.2	-	Consistent with lower limit shown on Figure 15.0.4-1	Yes	0
	Uncontrolled rod cluster control assembly bank withdrawal at power	LOFTRAN	-	Figure 15.0.3-2 and 0.43	lower and upper[a]	Yes	3427
	Rod cluster control assembly misalignment	THINC,TURTLE LOFTRAN, LEOPARD	-	Figure 15.0.3-2	lower[a]	Yes	3427
	Startup of an inactive reactor coolant loop at an incorrect temperature	LOFTRAN, FACTRAN, THINC	-	0.43	lower[a]	Yes	2399
	Chemical and Volume Control System malfunction that results in a decrease in the boron concentration in the reactor coolant	NA	NA	NA	NA	NA	0 and 3425

TABLE 15.0.3-2 (Page 4)

	Faults	Computer Codes Utilized	Reactivity Coefficients[a] Assumed Moderator Temperature (Δk/°F)	Moderator Density (Δk/gm/cc)	Doppler	Improved Thermal Design Procedure	Initial NSSS Thermal Power Output Assumed (MWt)
	Inadvertent loading and operation of a fuel assembly in an improper position	LEOPARD, TURTLE	-	NA	NA	NA	3427
	Spectrum of rod cluster control assembly ejection accidents	TWINKLE, FACTRAN, LEOPARD	Refer to Section 15.4.8 min., max. feedback	-	Consistent with lower limit shown on Figure 15.0.4-1	NA	0 and 3427
15.5	Increase in Reactor Coolant Inventory						
	Inadvertent operation of the ECCS during operation	LOFTRAN	-	Figure 15.0.3-2	lower[a]	Yes	3427
15.6	Decrease in Reactor Coolant Inventory						
	Inadvertent opening of a pressurizer safety or relief valve	LOFTRAN	-	Figure 15.0.3-2	upper[a]	Yes	3427

Q440.123

TABLE 15.0.3-2 (Page 5)

Faults	Computer Codes Utilized	Reactivity Coefficients[a] Assumed Moderator Temperature ($\Delta k/^{o}F$)	Reactivity Coefficients[a] Assumed Moderator Density ($\Delta k/gm/cc$)	Doppler	Improved Thermal Design Procedure	Initial NSSS Thermal Power Output Assumed (MWt)
Steam generator tube failure	NA	NA	NA	NA	NA	3581
Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	SATAN-VI, WFLASH, WREFLOOD, COCO, LOCTA-IV	See Section 15.6.5, references	-	See Section 15.6.5, references	NA	3581

NA - Not Applicable

level exhibit normal readings, then a steam generator tube rupture is diagnosed to have occurred. The recovery procedures for the double ended rupture of a steam generator tube can be found in Reference 3. These procedures are presented for a plant with a high pressure safety injection system and low pressure safety injection system.

Results

Figure 15.6.3-1 illustrates the flow rate that would result through the ruptured steam generator tube. The previous assumptions lead to an estimate of 102,259 pounds for the total amount of reactor coolant transferred to the secondary side of the faulted steam generator as a result of a tube rupture accident. The integrated steam flow is 55,420 pounds released through the safety valves.

Q440.127

Figure 15.6.3-2 Reactor Coolant System Pressure
Figure 15.6.3-3 Reactor Coolant System Temperature
Figure 15.6.3-4 Steam Generator Pressure (For Faulted Steam Generator)
Figure 15.6.3-5 Steam Generator Temperature (For Faulted Steam Generator)
Figure 15.6.3-6 Pressurizer Water Volume
Figure 15.6.3-7 Steam Generator Flow

The DNB calculations performed with LOFTRAN (Reference 1) indicate that DNB limits are met.

In Table 15.6.3-1 the sequence of events are presented. These events are the normal plant response to the normal plant setpoints. Loss of offsite power at reactor trip and no operator actions were assumed.

15.6.3.3 Environmental Consequences

The postulated accidents involving release of steam from the secondary system do not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. A conservative analysis of the postulated steam generator tube rupture assumes the loss of offsite power and involves the release of steam from the secondary system caused by a turbine trip in conjection with loss of main steam dump capabilities, and subsequent venting to the atmosphere. A conservative analysis of the potential offsite doses resulting from this accident is presented assuming primary to secondary leakage. This analysis incorporates assumptions of 1 percent defective fuel and steam generator leakage of 1 gpm prior to the postulated accident for a time sufficient to establish equilibrium specific activities in the secondary system. Three postulated cases are analyzed:

Case 1 - No iodine spike

Case 2 - Pre-existing iodine spike

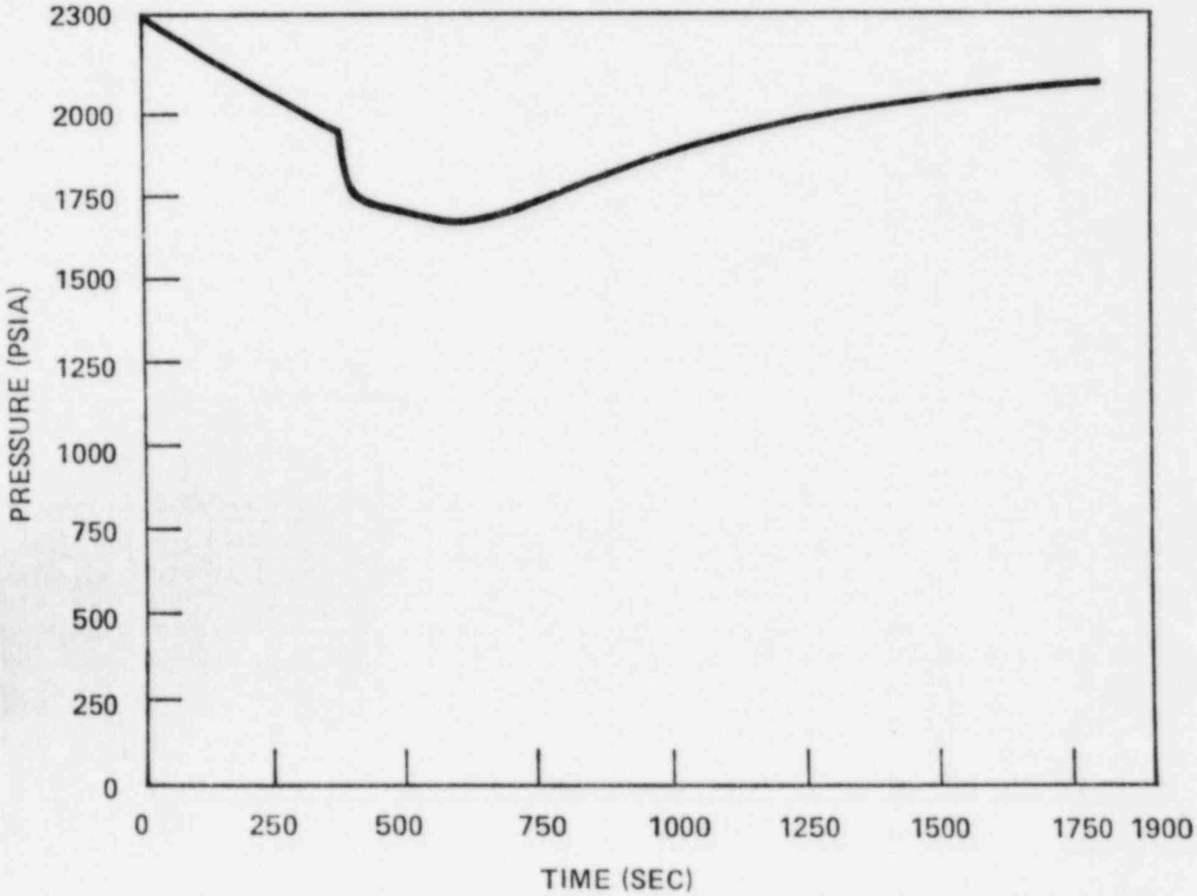
Case 3 - Coincident iodine spike

TABLE 15.6.3-1

STEAM GENERATOR TUBE RUPTURE SEQUENCE OF EVENTS

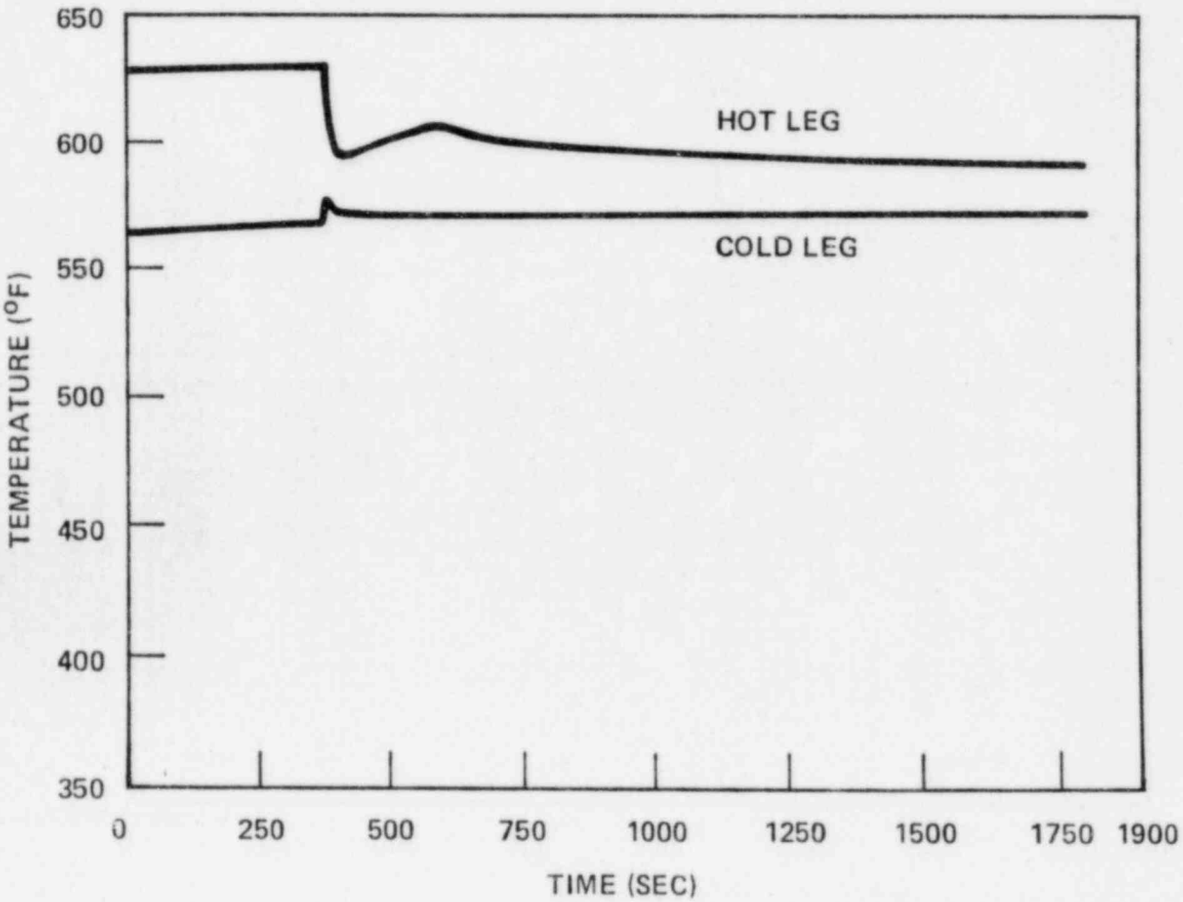
	Event	Time (seconds)
	Tube Rupture Occurs	0.0
Q440.127	Reactor Trip Signal	367.0
	Rod Motion	369.0
	Feedwater Terminated	368.0
	Steam Generator Safety Valves Opened (assumed to stay open to maximize release)	376.0
	S.I. Signal	542.0
	S.I. Injection	567.0
	Auxiliary Feedwater Injection	602.0
	Assumed that operator completes actions to isolate and equilibrate	1800.0

Q440.127



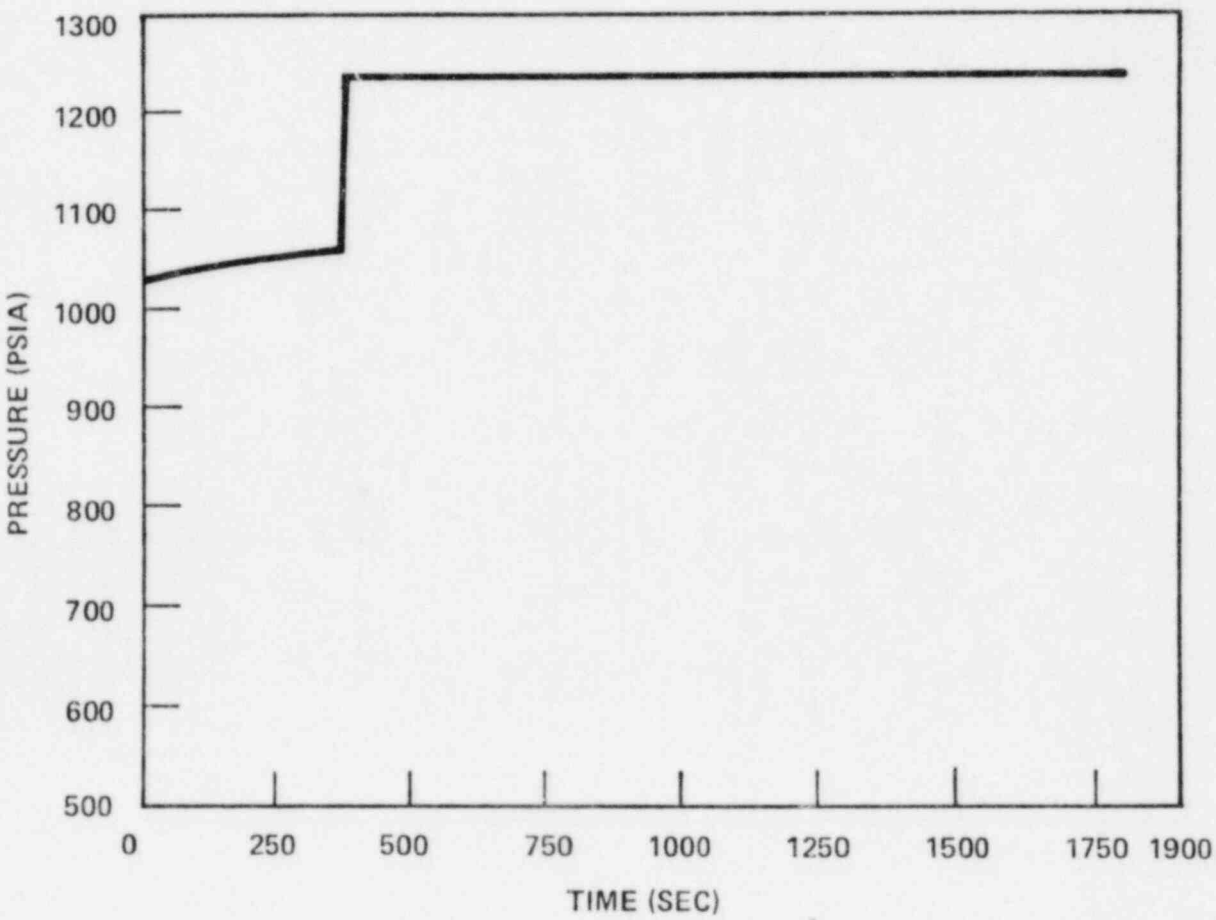
REACTOR COOLANT SYSTEM
PRESSURE
CATAWBA NUCLEAR STATION
Figure 15.6.3-2
Rev. 6

Q440.127



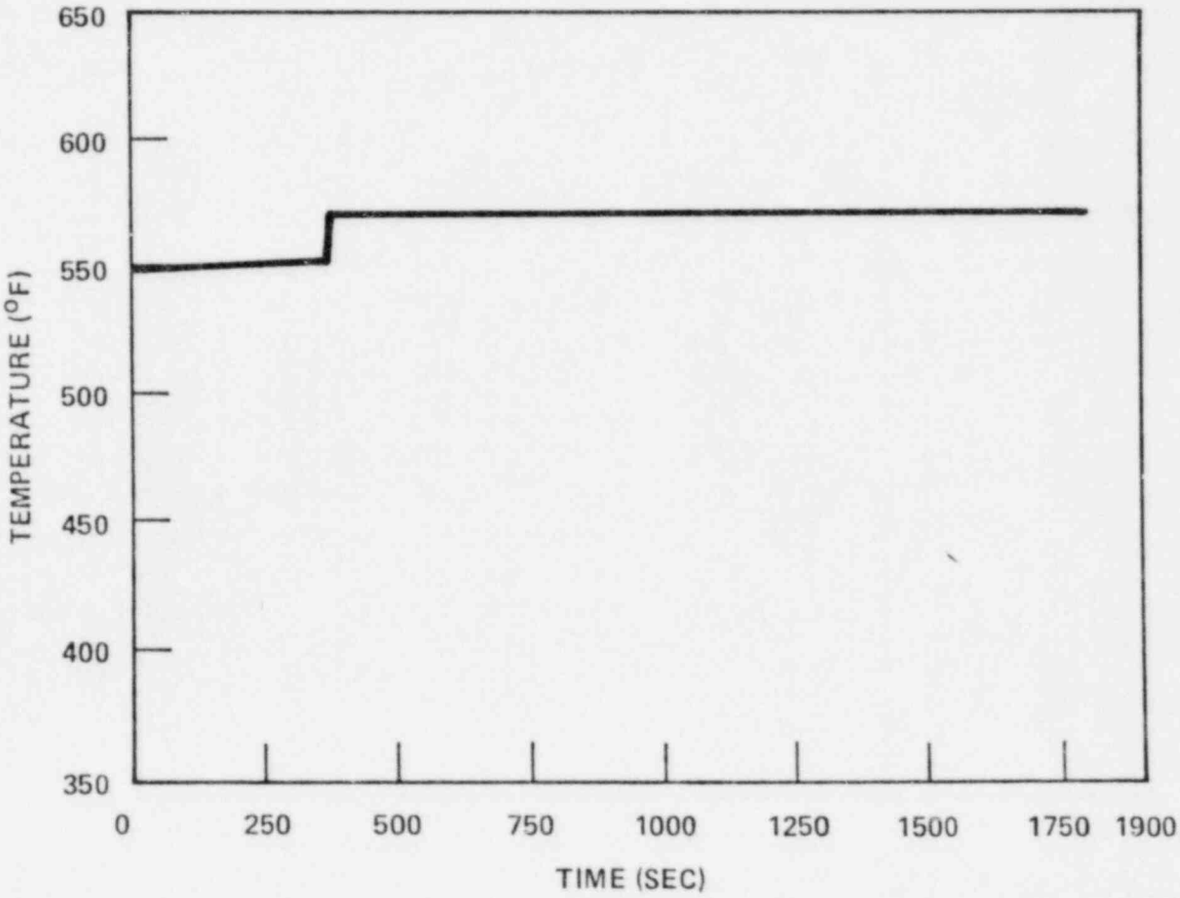
REACTOR COOLANT SYSTEM
TEMPERATURE
CATAWBA NUCLEAR STATION
Figure 15.6.3-3
Rev. 6

Q440.127



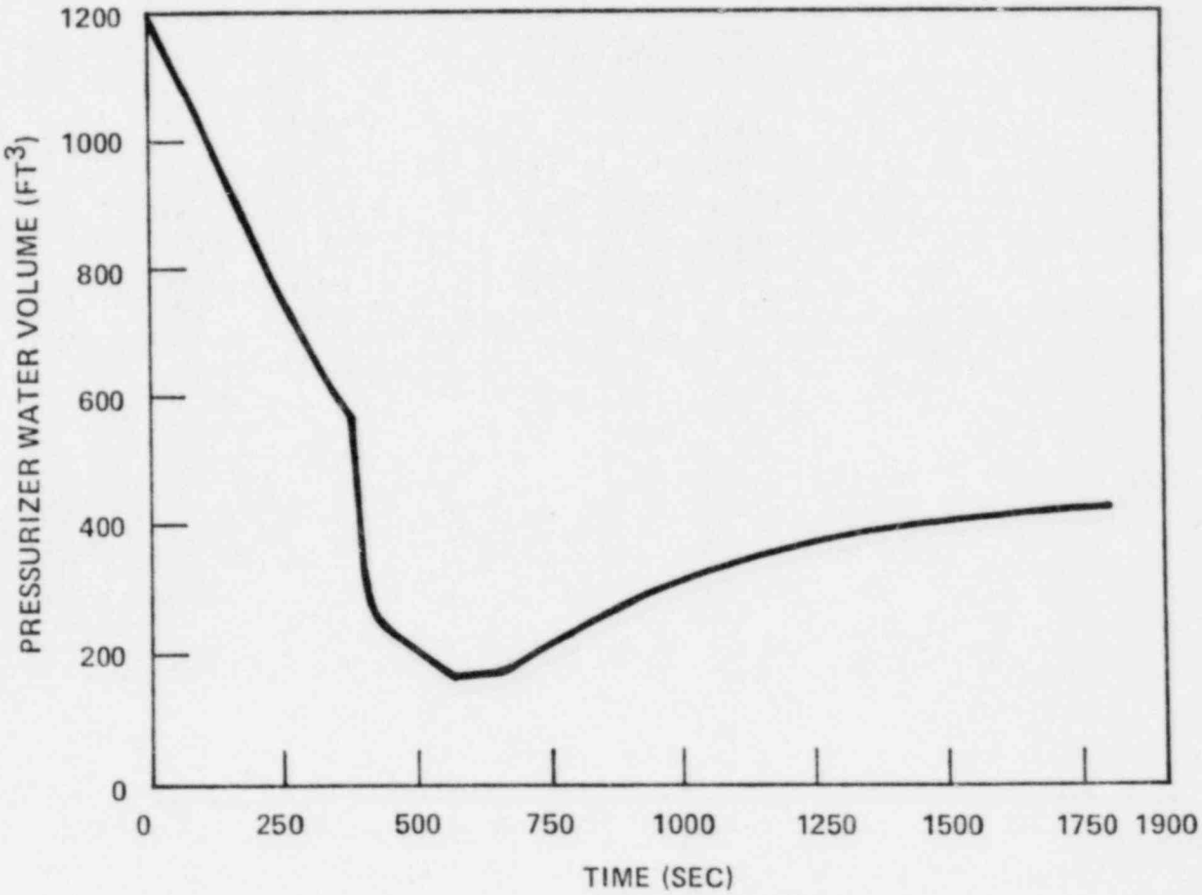
STEAM GENERATOR PRESSURE
CATAWBA NUCLEAR STATION
Figure 15.6.3-4
Rev. 6

Q440.127



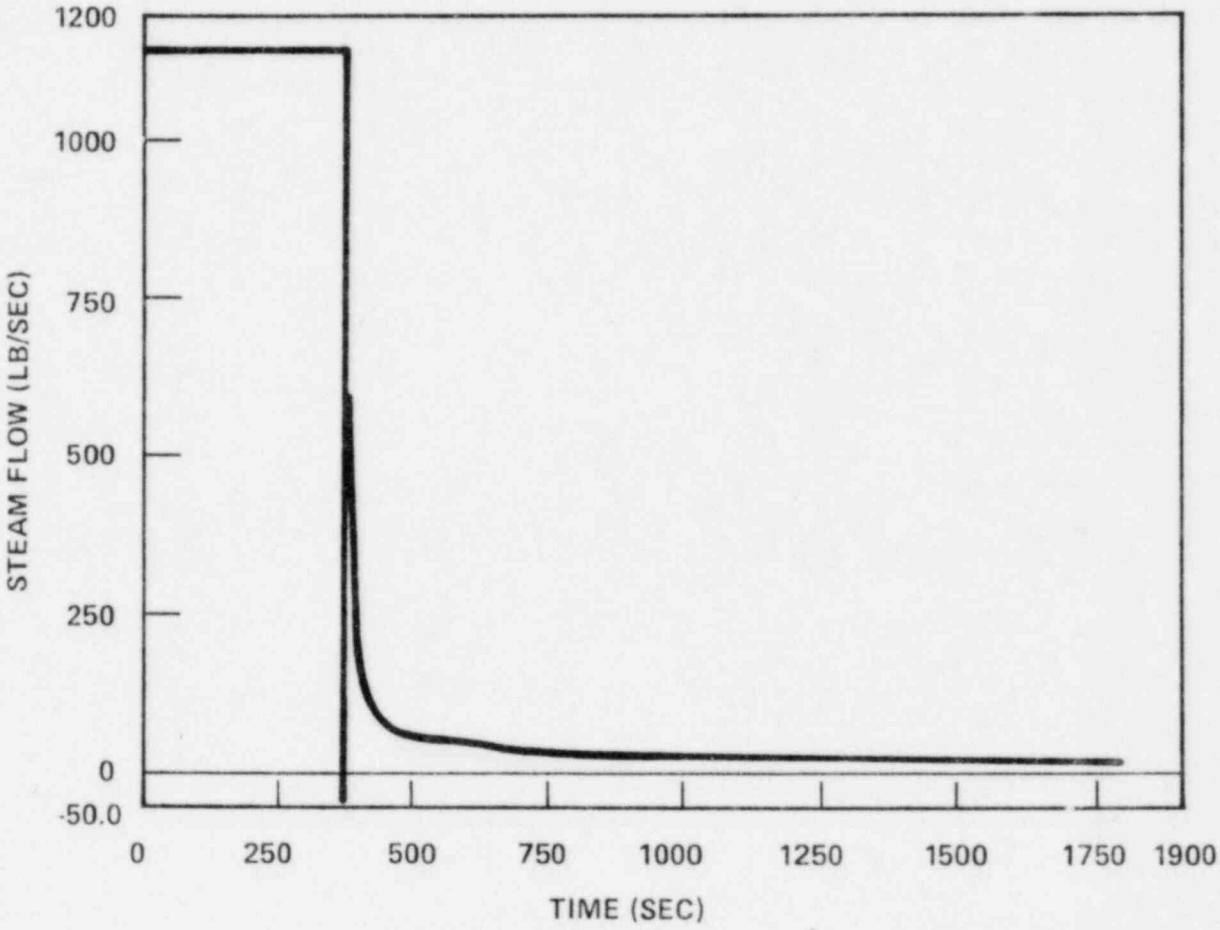
STEAM GENERATOR TEMPERATURE
CATAWBA NUCLEAR STATION
Figure 15.6.3-5
Rev. 6

Q440.127



PRESSURIZED WATER VOLUME
CATAWBA NUCLEAR STATION
Figure 15.6.3-6
Rev. 6

Q440.127



STEAM GENERATOR FLOW

CATAWBA NUCLEAR STATION

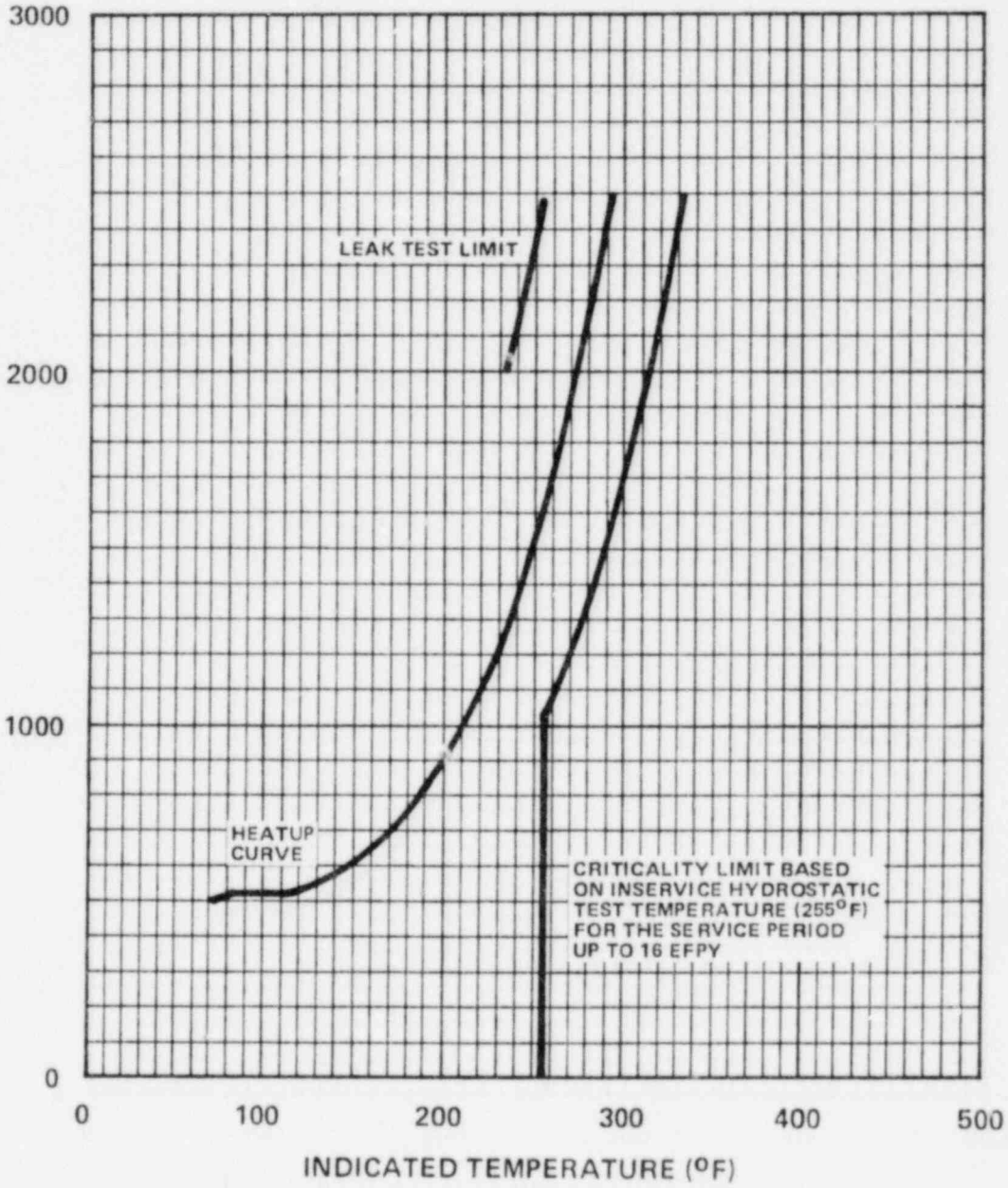
Figure 15.6.3-7

Rev. 6

MATERIAL PROPERTY BASIS

COPPER CONTENT	-	CONSERVATIVELY ASSUMED TO BE 0.10 WT% (CONTENT = 0.07 WT%)
RT_{NDT} INITIAL	-	CONSERVATIVELY ASSUMED TO BE 40°F (RT_{NDT} = 33°F)
RT_{NDT} AFTER 16 EFPY	-	1/4T, 110°F 3/4T, 87°F

CURVE APPLICABLE FOR HEATUP RATES UP TO 60°F/HR FOR THE SERVICE PERIOD UP TO 16 EFPY AND CONTAINS MARGINS OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS



CATAWBA UNITS 1 AND 2 REACTOR COOLANT SYSTEM HEATUP LIMITATIONS APPLICABLE UP TO 16 EFPY

CATAWBA NUCLEAR STATION

Figure Q440.8-1
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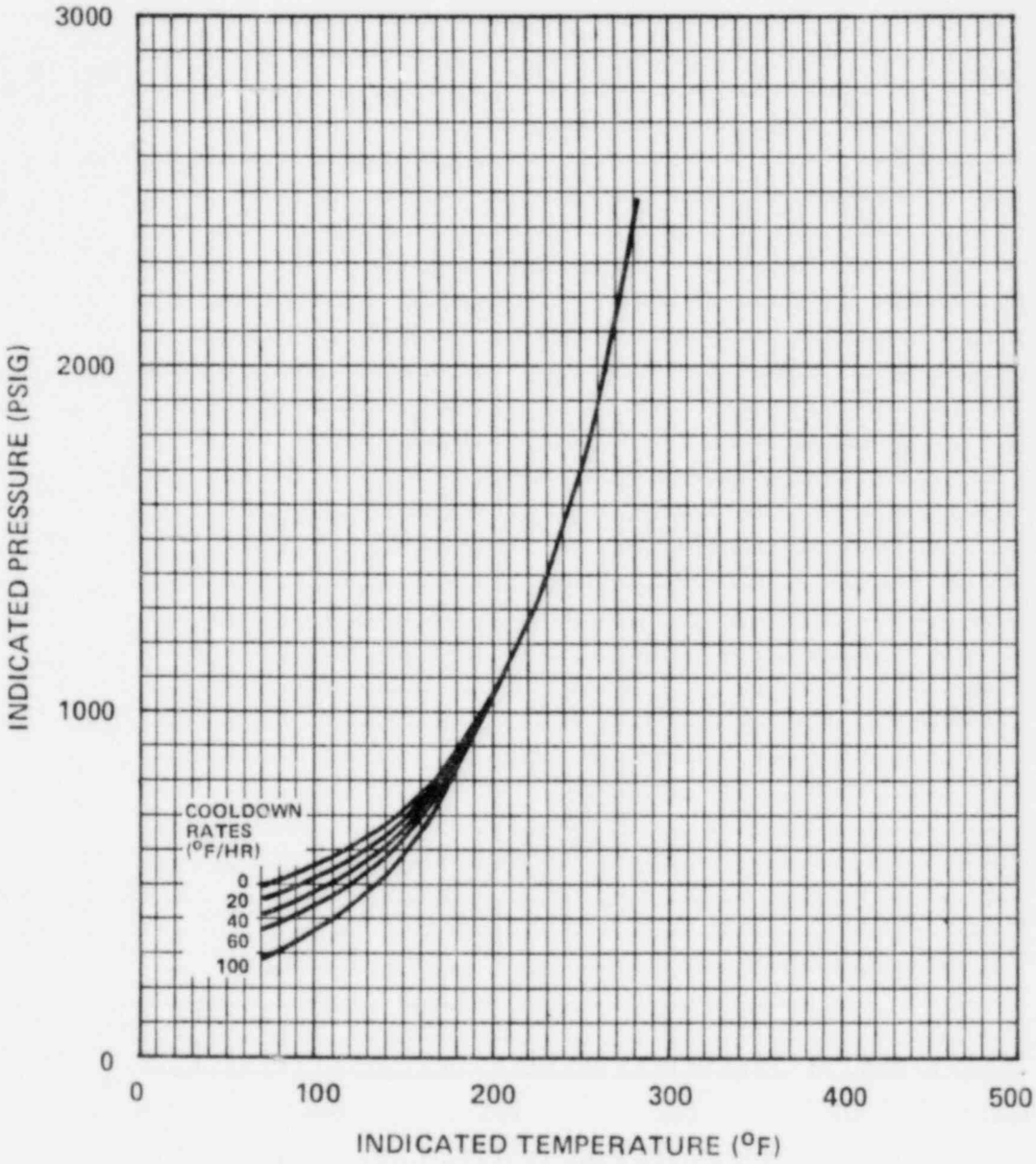
MATERIAL PROPERTY BASIS

COPPER CONTENT	-	CONSERVATIVELY ASSUMED TO BE 0.10 WT% (CONTENT = 0.07 WT%)
RT_{NDT} INITIAL	-	CONSERVATIVELY ASSUMED TO BE 40°F (RT_{NDT} = 33°F)
RT_{NDT} AFTER 16 EFPY	-	1/4T, 110°F 3/4T, 87°F

CURVE APPLICABLE FOR COOLDOWN RATES UP TO 100°F/HR FOR THE SERVICE PERIOD UP TO 16 EFPY AND CONTAINS MARGINS OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS



CATAWBA UNITS 1 AND 2 REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS APPLICABLE UP TO 16 EFPY

CATAWBA NUCLEAR STATION

Figure Q440.8-2

Rev. 6

normal and accident conditions. Additionally, the unit can be maintained safely at hot standby for an extended period of time from outside the control room. A list of instrumentation and controls and a description of the remote shutdown panels is in Section 7.4.

440.20 (App. 5-A) The auxiliary spray valve fails closed on loss of air or power. In this case you indicate the valve may be opened by using a portable compressed air or nitrogen bottle supply. Specify the seismic category of this valve, the operator, and controls. Describe the procedures for opening the valve with portable compressed air or nitrogen bottle supply. Discuss the availability of this equipment and communication with the control room.

If the spray valve is stuck closed as a result of mechanical failure, you state the pressurizer power operated relief valves may be used to depressurize the RCS. Provide the justification and procedures for using these valves for depressurization. Include in the discussions the effect on the RCS for only offsite power or onsite power available, single failures including common failures, seismic classification of components and controls for valve operators, and the effect of discharged fluid that could lead to discharge to the containment via the pressurizer relief tank.

Response:

Guidance for development/preparation of detailed procedures for the major NSSS related emergency contingencies are provided in the "Westinghouse Owners Group Emergency Response Guidelines," issued in September 1981. For example, E-3 of these Westinghouse Owners Group's Emergency Response Guidelines: "Steam Generator Tube Rupture Guideline," calls for the use of the pressurizer PORV to depressurize the RCS in the event that normal and auxiliary spray are not available. The use of pressurizer PORV's to depressurize the RCS is an inherent design function of the PORV's. Discussion is given in the Westinghouse Owner's Group Emergency Response Guidelines of cautions and background information for the various emergency contingencies.

The auxiliary pressurizer spray valve (tag number 1NV37A shown on Figure 9.3.4-1) is an 2" air diaphragm actuated gate valve. The pressure boundary of the valve is seismic Category 1. The valve and operator are qualified to stroke to the closed (safe) position upon release of air pressure in the operator during a DBE. Although the operator and controls are not seismically qualified, their failure during a DBE will not prevent the auxiliary pressurizer spray valve from closing.

This valve is located in lower containment in the pipe tunnel area. Should it become necessary to depressurize the RCS by this method, an operator could carry a small air bottle to the valve, disconnect

the normal air supply line and connect the bottle. The bottle is stored in a location readily accessible to the operator. There is a sound powered phone jack within approximately 20 feet of the valve which allows communication between the valve location and the control room.

440.21 (App. 5-A) This appendix states that "Should boration without letdown prove impractical due to any combination of plant conditions or equipment failures, letdown can be achieved by discharging RCS inventory via the pressurizer power operated relief valves or the reactor vessel head vent valves." Identify the factors that would make boration without letdown impractical. Provide the justification and procedures for using the pressurizer power operated relief valves or the reactor vessel head vent valves for letdown. Consideration should be given to single failures including common mode failures such as loss of power or air, safe shutdown earthquake, the effect on the RCS for only offsite power or onsite power available, and the effect of discharged fluid that could lead to a discharge to the containment and prevent access to the containment.

Suction lines to the other pumps are shown in Figures 9.2.7-1 (Refueling Water Storage Tank (FWST), common suction header and isolation valves to Residual Heat Removal Pumps), 5.4.7-1 and 5.4.7-2 (Residual Heat Removal Pumps), 6.2.2-1 (Containment Spray Pumps and isolation valves from FWST), 6.3.2-3 (Safety Injection Pumps and isolation valves from FWST), and 9.3.4-8 (Centrifugal Charging Pumps and isolation valves from FWST).

440.29 (6.3) Section 6.3.2.1 states "The component interlocks used in different modes of system operation are listed below." A list of all interlocks should be provided (for example, accumulator interlocks are not discussed). Details of these interlocks should be presented in appropriate Chapter 7 subsections and cross referenced. Confirm that the interlocks conform to the applicable criteria.

Response:

See response to Q440.108.

440.30 (6.3, 15.0) Certain automatic safety injection systems are blocked to preclude unwanted actuation of these systems during normal shutdown and start-up conditions. Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation, operator procedures and time frame available to mitigate the consequences of such an accident, and the consequences of the accident.

Response:

During a normal startup or shutdown, automatic SI actuation signals from low pressurizer pressure and low steamline pressure may be manually blocked.

If a steamline rupture occurs while both of these SI actuation signals are blocked, steamline isolation will occur on high negative steam pressure rate. An alarm for steamline isolation will alert the operator of the accident.

For large LOCA's, sufficient mass and energy would be released to the containment to automatically actuate SI when the containment high pressure setpoint is reached. At this time, the operator would be alerted to the occurrence of a LOCA by the following safety-related indications:

1. loss of pressurizer level,

2. rapid decrease of RCS pressure,

3. increase in containment pressure, and

4. increase in the recirculation sump water level.

In addition to the above, the following indications are normally available to the operator at the control board:

1. radiation alarms inside containment,

2. decrease off scale of accumulator water levels and decrease in pressure,

3. ECCS valve and pump position and status light in ECCS energized indication, and annunciators light as safeguards equipment becomes energized, and

4. flow from ECCS pumps.

For very small LOCA's (approximately less than 2-inch diameter) in which the containment high pressure setpoint may not be reached, the operator would observe the safety-related indications plus the first normally available indication.

In addition, a charging flow/letdown mismatch would provide the operator with another indication of leakage from the RCS. Since the operator would observe the pressurizer level and receive additional indications that a LOCA occurred, a manual SI would be initiated immediately. As presented in WCAP-8356, the time to uncover the core following a small break is relatively long (e.g., greater than 10 minutes for a 2-inch break). The operator would, therefore, have sufficient time to manually initiate SI.

440.31 (6.3) Provide a detailed design drawing of the containment recirculation sump. Discuss any anti-vortex criteria which were used in the sump design. Describe the containment water level instrumentation, its availability following a LOCA, and its capability for measuring the containment flood level. What is the maximum possible flood level and the basis for this level? What is the seismic category and quality class of the sump structure?

Response:

A drawing of the containment recirculation screen assembly is shown in Figure 6.2.2-3. The screen assemblies will be designed to withstand a SSE.

TABLE Q440.52-1

RESPONSE TIMES AND DISCHARGE RATES ASSUMED FOR CHAPTER 15 EVENTS

COMPONENT	RESPONSE TIME	CAPACITY
Main Steam Isolation Valves	2 second logic delay & 5 second closure time(1)	-----
Main Feed Isolation Valves	2 second logic delay & 5 second closure time(1)	-----
Pressurizer Power Operated Relief Valves	Full Open 15 PSI Above Setpoint(6)	3 Valves @ 210,000. lbm/hr per valve(6)
Pressurizer Safety Valves	Full Open at 3% accumulation Above Set Pressure(2)	3 Valves @ 420000. lbm/hr per valve(5)
Steam Generator Safety Valves	Full Open at 3% Accumulation Above Set Pressure(2)	120% of Rated Full Power Steam Flow. (Rated Steam Flow = 15.14×10^6 lbm/hr).(4)
Aux Feed Pumps	60 Second Delay Assumed with or without Offsite Power(1)	Feedline Rupture - 492 GPM to Two Intact-Steam Generators(3) Loss of Feed W/AC-810 GPM Uniform to all SG.(3) Loss of Feed W/O AC-500 GPM Uniform to all SG.(3)

NOTES:

1. Technical Specifications require verification of the response times thru tests.

2. Technical Specifications require verification of that valves begin to lift at proper setpoint.

3. Technical Specifications require testing of auxiliary feed flows.

4. Valve capacity is certified by valve manufacturer using accepted industry standards.

5. Valve capacity will be verified through results from EPRI's PWR Safety & Relief Valve Test Program.

6. Valve stroke time and capacity will be verified through results from EPRI's PWR Safety & Relief Valve Test Program.

radioactive release to the atmosphere from the faulty unit. The recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam line. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily. Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the isolation procedure can be completed within 30 minutes of accident initiation. Included in this 30 minute time period would be an allowance of approximately 6 minutes to trip the reactor (automatic action), 10 minutes to identify the accident as a steam generator tube rupture and 15 minutes to isolate the faulted steam generator. Preliminary diagnosis of a steam generator tube rupture can be initiated prior to reactor trip. Consequently, although it may take slightly longer than 5 minutes for automatic reactor trip to occur, identification and isolation of the affected steam generator is expected to be completed within 30 minutes.

Immediately apparent symptoms of a tube rupture accident such as falling pressurizer pressure and level and increased charging pump flow are also symptoms of small steam line breaks and loss of coolant accidents. It is therefore important for the operator to determine that the accident is a rupture of a steam generator tube in order that he may carry out the correct recovery procedure. The accident under discussion can be identified by the following method. In the event of a complete tube rupture, it will be clear soon after the trip that the level in one steam generator is rising more rapidly than in the others.

Also this accident could be identified by either a condenser air ejector exhaust high radiation alarm or a steam generator blowdown radiation alarm.

The operator carries out the following major operator actions subsequent to reactor trip which lead to isolation of the faulted steam generator and minimizing primary to secondary leakage.

1. Identification of the faulted steam generator.

2. Isolation of the faulted steam generator.

3. Subcooling of NC system fluid to 50° below no-load temperature.

4. Depressurization of the NC system to terminate breakflow, and

5. Terminating safety injection.

Loss of Coolant Accident: See Table 440.56-4

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. Only limited manual actions are required by the operator to realign the system for the cold leg recirculation mode of operation, and, at approximately 24 hours, for the hot leg recirculation mode of operation. These actions are delineated in Table 440.56-4.

440.107
(6.3)
(440.28)

Your response to Question 440.28 is not complete. Provide an evaluation of your conformance to Branch Technical Position RSB 6-1, Item B.5. Identify and justify any deviations from this position.

Response:

The response to Question 440.28 indicates compliance with regulatory position B.5 of BTP RSB6-1.

Of the three pairs of ECCS pumps only the residual heat removal pumps (RHRP's) have suction piping that can supply water either from the refueling water storage tank (FWST) or directly from the containment recirculation sump. The physical arrangement of this equipment has the FWST at grade elevation, the recirculation sump bottom approximately 41' below grade and the RHRP suction approximately 68' below grade elevation. With all valves open, flow would be from the FWST to the sump and to the RHRP suction. Thus, this arrangement does not preclude automatic switchover.

There is one motor operated gate valve between the containment sump and each pump suction while the line from the FWST to each pump contains both a motor operated gate valve and a check valve. (Refer to Figures 6.3.2-4, 5.4.7-1, and 9.2.7-1.) Failure of the motor operated valves is analyzed in Table 6.3.2-5 (items 13 and 14). This shows that assuming single failure, adequate core cooling is available and does not result in establishment of a path that would allow release of radioactive material to the environment.

440.108
(6.3)
(440.29)

Your response to Question 440.29 is inadequate and is most likely based on your withdrawn FSAR and not the current FSAR. Provide the response to Question 440.29. Sections 6.3.2.1 and 7 and Table 6.3.2-3 should be consistent and complete.

Response:

Table 6.3.2-3 has been revised to include all electric motor operated valve interlocks in the ECCS. Interlocks for the UHI hydraulic cylinder operated gate valves are discussed in Section 7.6.3 and in Table 6.3.2-5.

The purpose of the interlocks and automatic features for the valves in Table 6.3.2-3 are listed below by function.

Cold Leg Accumulator Isolation Valves - Assures valves are open during power operation.

ND Suction From FWST - Prevents valves from opening during post accident recirculation operation of ECCS.

ND Pump Discharge to CCP (NI Pump) - Prevents flow of recirculation sump fluid to FWST, prevent possible overpressure of pipe during cooldown, permits alignment to supply NI & CC pumps only during recirculation.

Containment Sump Valve - The interlocks prevent the control room operator from opening the sump valves and flooding containment with fluid from the reactor coolant system or the FWST. The automatic features override the interlocks and open the valve if the FWST level is low and an "S" signal has been generated (this prevents the sump valve from opening and flooding containment during refueling as the FWST is emptied into the refueling cavity).

CCP Normal Suction - Isolates normal charging sources after FWST is available to pumps.

NC to ND Isolation Valves - Interlocks prevent flow from RCS to FWST, spill of RCS to containment sump, potentially overpressuring CCP and NI pump suction lines, spraying RCS to containment via residual spray headers. Pressure interlocks and automatic feature prevent overpressure of the ND pump suction line.

NI Pump Miniflow - Interlocks prevent recirculation sump fluid from being pumped to FWST.

NS Suction from FWST - Prevents spill of FWST fluid to containment sump via ND piping.

NS Suction from Sump - Prevents spill of FWST fluid to containment sump and prevents containment spray with reactor coolant.

Residual Containment Spray - Prevents residual containment spray with reactor coolant.

440.109 (6.3 & 15.0) (440.29)

The response to Question 440.30 is incomplete. Feedwater pipe breaks should also be discussed. For each type of pipe break in the primary and secondary systems, provide the information requested in Question 440.30. Time response for operation reaction (credit only given from time of receipt of control room alarm from safety grade instrumentation) should be discussed, and may be based on ANSI N660 criteria when determining accident consequences. The accident description and discussions of consequences should take into consideration the available mitigating equipment as a function of pressure.

Response:

If a feedline rupture occurs while both SI actuation signals are blocked, a low-steam generator water level alarm will be generated followed by a low-low steam generator water level signal. Auxiliary feedwater flow is initiated on receipt of low-low steam generator

justify the Catawba design for the scenario of concern in Question 440.40. Justify the Catawba design against the Question 440.40 scenario by providing a chronological timetable indicating initiation of event, indications and alarms (credit given for operator corrective action only upon receipt of control room alarm) at Catawba and times at which they occur, time available to take operator action (after alarm) before pumps are damaged, and subsequent scenario analysis if an acceptable operator action time to avert pump damage cannot be justified. In the analysis justify the number of charging pumps assumed to be running.

Response:

See revised response to Question 440.40.

440.113
(6.3)
(440.46)

The response to Question 440.46 indicated that recirculation sump tests are not intended for Catawba. This is unacceptable. Our position is that Catawba must reference and justify suitable sump tests (whether from another plant, from model tests, or by in-plant testing at Catawba) to demonstrate acceptable ECCS sump design.

Response:

The scale model testing done by Alden Research Laboratory for the McGuire Nuclear Station will be referenced to demonstrate acceptable ECCS recirculation sump design at Catawba. Alden has reviewed the preliminary design drawings of the Catawba recirculation screen assemblies. They made some recommendations for minor changes in the design (which have been incorporated) and, based on their review, felt that no seperate model study of the Catawba sump would be needed.

The similarity between the McGuire and Catawba containment recirculation screen assemblies is a result of virtually identical containment designs, nuclear steam supply systems, emergency core and containment cooling system and a conscious attempt to keep the basic geometry of the Catawba assembly as close as possible to the design Alden tested and approved for McGuire.

The required flowrates that the recirculation screen assemblies must handle are virtually identical to those tested on the McGuire model. The area of the fine screen is larger than at McGuire which reduces the velocity of the fluid passing through the screen. The recirculation screens are located in the same position inside containment at both plants. Because the containment design and major equipment are virtually identical minimum recirculation sump levels for a given volume of fluid are essentially identical for the two plants.

440.114
(15.0)

The response to Question 440.58 regarding the content of the Technical Specifications is not consistent with the FSAR. Provide the

(440.58) updated Technical Specifications as described in the response to Question 440.58.

Response:

See Section 16.0 for a discussion of the Catawba Technical Specifications.

440.115 (5.2.2) (440.7) Your response to Question 440.7 was not complete. Specifically, discuss how you conform to each of the nine items under Section B of Branch Technical Position RSB 5-2 in NUREG-0800. Identify and justify any deviations from this position.

Response:

440.116 (5.2.2) (440.9) Your response to Question 440.9 is not adequate. The staff's position is that the overpressurization protection system should be able to perform its function assuming any single active component failure.

Evaluate the effect of the DC power failure scenario discussed in Question 440.9 on the RHR system. Demonstrate that the RHR system and the PORVs will provide low temperature overpressurization protection. Provide the technical specifications for the PORVs and RHR system with regard to operation for low temperature overpressurization protection.

Response:

The response to Question 440.9 indicated that the Reactor Coolant System is provided low temperature overpressure protection by other means in addition to the PORV based system described in Section 7.6.21. It is possible to have a DC power bus failure which both isolates the normal letdown flowpath and fails closed one PORV, as specified in Question 440.9, although this does not necessarily initiate an overpressure event. If the other PORV is postulated failed closed, per Question 440.9, this does not fail all mitigating systems.

In particular, the RHR inlet relief valves provide low temperature overpressure protection when either, or both, RHR inlet lines are open to the Reactor Coolant System. These relief valves are sized to relieve the combined flow of all the charging pumps at their set pressure of 450 psig. (Reference Section 5.4.7.1).

Also, operating procedures call for a pressurizer bubble to be maintained whenever the RHR system is isolated. The steam bubble volume for low temperature conditions is 1350 ft^3 ± 5%. Alarms of the Reactor Coolant Protection System alert the operator to departure from the desired pressurizer level. Thus, even assuming a minimum steam

bubble volume and taking no credit for the charging flow control system operation, the plant operator would have in excess of 10 minutes to terminate the event.

It is concluded that the present design provides adequate low temperature protection and no design changes are necessary. However, in order to eliminate the potential of a DC bus failure isolating normal letdown and failing closed one PORV, design changes will be made, simply as a design improvement.

Technical Specifications will be provided as discussed in Chapter 16.

440.117 (5.4.7) (440.15) Your response to Items d and e of Question 440.15 was not complete. Specifically, identify the "noncredible" events excluded from the analysis and the basis for the exclusion. Describe these events and their consequences, including the discharge of the UHI accumulator and the combined flow of the safety injection pumps. Describe any operator procedures related to the accidental pressurization events. The typographical errors in the response to Question 440.15 should be corrected to clarify the discussion.

Is each one of the four RHR suction motor-operated valves aligned to a separate motor control center?

Response:

Refer to the response to question 440.115.

There are two motor control centers which serve the four motor operated isolation valves. Each motor control center serves one of the series isolation valves in both of the suction lines. The power sources for the motor control centers are seperate and redundant such that a single failure will not prevent accomplishment of the safety function of these valves which is to isolate the suction line.

440.118 (6.3) (440.24) The response to Question 440.24 was not complete. Show that the failure of any non-seismic Category 1 equipment and piping in the line to the spent fuel pool makeup does not affect the ability of the RWST to perform its intended safety-related function. A listing of drawing and figure cross references should be provided on Figure 9.2.7-1.

Response:

The makeup line from the Refueling Water System to the Spent Fuel Cooling (KF) System connects to two, normally closed, EMO valves in series in the KF system. They are KF101B and KF103A as shown on Figure 9.1.3-1. Both valves are automatically closed by a

safety injection initiation signal. This section of piping, including both KF valves, is seismic and serves to isolate the RWS from nonseismic piping which is part of the interfacing KF system.

A listing of figure cross references is provided on revised Figure 9.2.7-1.

440.119
(6.3)
(440.41)

In regard to the response to Question 440.41, commit that you will (a) make the adjustments necessary to assure that no one ECCS branch has an unacceptable low or high resistance by measuring the flow in each pipe during the preoperational tests, (b) analyze the test results to ensure there is sufficient total line resistance to prevent excessive runout of the pumps and adequate NPSH under the most limiting system alignment, (c) verify that the maximum flow rate from the test results confirms the maximum flow rate used in the net positive suction head calculations under the most limiting conditions, and (d) confirm that the minimum acceptable flows used in the loss-of-coolant accident analysis are met by the measured total pump flow and a relative flow between the branch lines.

Response:

Refer to Table 14.2.12-1 (Page 29), Safety Injection System Functional Test.

440.120
(15.0)
(440.61)

Your response to Question 440.61 is not acceptable. For each incident of moderate frequency that is analyzed in Chapter 15.0, including the complete loss of forced reactor coolant flow incident, provide the following information:

(1) Identify and justify your selection of the single active component failure or operator error that is the most limiting.

(2) Provide an analysis that shows the moderate frequency incident in combination with the most limiting single active component failure or operator error will not result in loss of any barrier other than a limited number of fuel rod cladding perforations. Fuel failure should be assumed for all rods for which DNBR is below the limit value unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. Specify the number of fuel failures.

(3) Provide a discussion of the long-term effects and events for each moderate frequency incident in combination with the most limiting failure. If operator action is needed, provide a complete assessment of the operator's role and show that sufficient time is allowed for operator action to be accomplished.

Response:

(1) All of the transients analyzed in Chapter 15.0 are analyzed assuming the most limiting single failure (e.g., loss of one protection signal (e.g., loss of one protection signal or SI train failure). For the incidents of moderate frequency, including the complete loss of forced reactor coolant flow, the analysis shows that the DNBR remains above the limit value. Therefore, no fuel failure will occur.

The attached Table Q440.120-1 lists all the incidents of moderate frequency along with the worst single failure assumed and the effect such an assumption has on the results. For most accidents, the worst single failure has no effect at all, since the logic of the protection system (e.g. 2 out of 4) is designed to account for this.

(2) The basis for performing the Chapter 15.0 analysis includes allowing for the worst single failure in the protection system. For example, the electrical aspect of this criterion, as stated in IEEE 279-1971, is met that "any single failure within the protection system shall not prevent proper protective action at the system level when required." The Catawba FSAR meets the worst single failure criterion. The SRP states that "an incident of moderate frequency in combination with any single active component failures, or single operator error, should not cause loss of function of any barrier other than the fuel cladding." This criterion is met in the FSAR by the fulfillment of the design basis for incidents of moderate frequency.

(3) See Response to Question 440.56.

TABLE Q440.120-1 (Page 1)

SINGLE FAILURES ASSUMED FOR ACCIDENTS OF MODERATE FREQUENCY

Event Description	Section	Worst Failure Assumed	Effect
Feedwater temperature reduction	15.1.1	(1)	none
Excessive feedwater flow	15.1.2	One protection train	none
Excessive steam flow	15.1.3	(1)	none
Inadvertent secondary depressurization	15.1.4	One safety injection train	delays boron to core
Loss of external load	15.2.2	One protection train	none
Turbine trip	15.2.3	One protection train	none
Inadvertent closure of MSIV	15.2.4	One protection train	none
Loss of condenser vacuum	15.2.5	One protection train	none
Loss of ac power Loss of normal feedwater	15.2.6 15.2.7	One auxiliary feedwater pump One auxiliary feedwater pump	Increases primary heatup
Loss of forced reactor coolant flow	15.3.1 & 2	One protection train	none
RCCA bank withdrawal from subcritical	15.4.1	One protection train	none
RCCA bank withdrawal at power	15.4.2	One protection train	none
Dropped RCCA, dropped RCCA bank	15.4.3	One nuclear instrumentation system channel	none
Statically misaligned RCCA	15.4.3	(2)	none
Single RCCA withdrawal	15.4.3	One protection train	none

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TABLE Q440.120-1 (Page 2)

SINGLE FAILURES ASSUMED FOR ACCIDENTS OF MODERATE FREQUENCY

Event Description	Section	Worst Failure Assumed	Effect
Inactive RC pump startup	15.4.4	One protection train	none
Uncontrolled boron dilution	15.4.6	Standby charging pump is operating	Reduces time to criticality
Inadvertent ECCS operation at power	15.5.1	One protection train	none
Increase in RCS inventory	15.5.2	One protection train	none
Inadvertent RCS depressurization	15.6.1	One protection train	none
Failure of small lines carrying primary coolant outside containment	15.6.2	(2)	none

(1) No protective action required.

(2) No transient analysis involved.

440.121
(15.3.3)
(440.84)

In response to Question 440.84 you state that $Zr-H_2O$ reaction on the inner clad surface is not applicable because no clad failures occur. Fuel failure (perforation) must be assumed for all rods for which DNBR falls below the limit value unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. Therefore, either substantiate that no clad failures occur, or evaluate the effects of fuel failure for all rods with a DNBR less that the limit value. Include in this evaluation the release of gas from the rod and metal-water reaction on the inner rod surface. Show that the core will remain in place and intact with no loss of core cooling capability.

Response:

The statement in the response to Question 440.84 that 9% of the rods experience DNB ratios less than the limit value is incorrect. This value was inadvertently included in Table 15.3.3-2. The correct number of rods that experience DNB ratios less than the limit value for the Catawba is 0%, and therefore, no clad failures occur.

Even so, Westinghouse has developed an evaluation procedure for the locked rotor accident which treats fuel failure on a mechanistic basis, thus, eliminating the need to automatically equate DNB with fuel rod failure. In this method, the transient time-temperature history of the fuel rod is compared with oxidized clad failures as given in Reference 1. In addition, the evaluation procedure considers other potential fuel rod failures mechanisms such as: fuel pellet melting, clad collapse or ballooning/bursting. Application of this evaluation procedure to the locked rotor accident as presented in Catawba FSAR showed that no fuel rod failures are predicted to occur for this incident. Thus, the radiological consequences of the locked rotor accident are similar to those for the loss of offsite power accident. The development and use of such mechanistic methods for quantifying fuel failure is specifically allowed by Section 4.2, of the NRC's Standard Review Plan (NUREG-0800). Furthermore, although Westinghouse has not previously taken credit for such an approach for licensing purposes, both Combustion Engineering and Babcock and Wilcox have submitted material to the NRC in approved Safety Analysis Reports which supports a similar position that DNB does not necessarily result in fuel rod cladding failure.

1. R. Van Houten, "Fuel Rod Failure as a Consequence of Departure from Nucleate Boiling or Dryout," NUREG-0562, June 1979.

440.122
(15.0)
(440.52)

The response to Question 440.52 is unacceptable. The title of Table Q440.52-1 is Chapter 15 Non-LOCA Data, which implies different data apply to accidents involving loss of primary coolant. This should be clarified. Supply the response times and the discharge rates assumed for the events analyzed in Chapter 15.0 and provide a discussion of how these values will be verified to be conservative.

Response:

The table should be propertly titled "Response Times and Discharge Rates Assumed for Chapter 15 Events."

440.123 (15.1.3) (440.63) The response to Question 440.63 notes that the figures in Section 15.1 were revised. The reason for these changes should be specified. The text and tables associated with these figures have not been changed which could indicate that the initial analysis was in error or the analytical methods are being changed. The text and tables in Chapter 15.0 should be revised to clearly indicate the analytical methods and assumptions being utilized for the analyses. This revision should include Section 15.0. For example, Table 15.0.3-3 references Table 15.0.3-2 for analyses using the improved thermal design procedures which should be identified in Table 15.0.3-2.

Response:

Fuel design changes necessitated the revision in Section 15.1. The text is correct. Table 15.0.3-2 is revised to show which events use the improved thermal design procedure.

440.124 (5.2.2) (440.11) The response to Question 440.11 indicates that WCAP-7769, Revision 1, is applicable to the Catawba plant. Section 15.2.2.1 of the Catawba FSAR states that the turbine trip event is a more severe transient than loss of external load. Section 15.2.3 of the FSAR on the turbine trip analysis shown that for a reactor trip on the first reactor protection signal the peak pressurizer pressure is in excess of that reported in WCAP-7769. Explain this difference and show for the turbine trip event that overpressure protection is provided for both of the following cases:

(a) Credit for all safety valves assuming reactor trip on the second reactor protection system signal.

(b) Failure of one pressurizer safety valve to open assuming trip on the first reactor protection system signal.

Other assumptions should be consistent with the analysis currently presented in Section 15.2.3 of the FSAR.

Response:

WCAP-7769, Revision 1 differentiates between the loss of load transient with the steam dump and RCS pressure control systems functioning and the turbine trip event. The transient as discussed in the WCAP (p. 3-35) is the turbine trip event without direct reactor trip. That the FSAR depicts a higher peak pressure than that shown in the WCAP (Figure 3-24) is due to rod motion delay time. WCAP-7769 assumed 1 sec for rod motion following reactor trip setpoint versus 2 sec assumed for the FSAR. (The 2 second delay is not unique to Catawba.)

Numerous analyses have been performed in support of the EPRI Safety and Relief Valve Test Program (NUREG-0737, Item II.D.1) wherein RCS

overpressure protection was addressed similar to that in WCAP-7769. Indeed, this particular transient was analyzed for the enveloping (worst case) 4-loop plant and presented in a report "Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves i Westinghouse-Designed Plants," EPRI Report NP-2296-LD, March 1982.

The maximum pressurizer pressure reported for this limiting event, 4-loop plant, was 2555 psia. Which agrees quite well with that shown in the FSAR (approximately 2550 psia). For the enveloping plant, the analysis conducted with the reactor tripping on the second RPS signal shows a peak pressurizer pressure of 2565 psia. The difference between the two reactor trip points (approximately two seconds) is diluted considering safety valve sizing and the assumptions for safety valve flow rate versus pressure used in the analyses (linear, from 0 to 100 percent over the pressure range of 2500 to 2575 psia):

Figure 2-1 of the WCAP shows that only 90 percent of safety valve flowrate is required to turn around the overpressure transient assuming no reactor trip. With 100 percent of safety valve capacity, the pressurizer pressure peaks at less than 2575 psia.

With reactor trip occuring at the first reactor trip setpoint, approximately 60 percent of total safety valve flow rate was required to turn around the overpressure transient (see WCAP-8879, Rev. 1).

440.125
(6.3)
(440.47)

Your response to Question 440.47 appears to cover only leakage from the RHR pump portion of an ECCS train. Expand your discussion to include the entire ECCS train to show ECCS train conformance to the criteria identified in Question 440.47.

The suction lines for the charging and safety injection pumps are designed for 235 psia. If the isolation valves between the RHR pump discharge and the charging or safety injection pump suction lines are open there is a potential for overpressurizing these lines. Discuss your means for preventing overpressurization and failure of these lines for all modes of ECCS operation (short and long term) assuming the most limiting single failure or operator error.

Response:

The maximum credible leak rate from the ECCS during long-term cooling is 50 gpm or less from one failed residual heat removal pump seal.

Excessive leakage flows via a floor drain from a faulted residual heat removal pump or containment spray pump to the ND (residual heat removal) and NS (containment spray) room sump on elevation 522'.

Excessive leakage from a faulted safety injection pump, centrifugal charging pump, or reciprocating charging pump flows via a floor drain

to Floor Drain Sump A (Unit 1) or Floor Drain Sump B (Unit 2). Both sumps are on elevation 537'. Sump level instrumentation and pumps in Floor Drain Sumps A & B are not safety related, therefore availability of these devices is not assumed. With no sump pumps operating, leakage from a safety injection or charging pump collects in one of the floor drain sumps.

If the sump overflows and the room fills to elevation 543', additional leakage will drain to the 522' elevation and collect in the ND and NS room sump. The ND and NS room sump has four ASME III, Class 3 pumps and level instrumentation. High and high-high sump levels are alarmed and sump pump discharge volume is totalized in the control room. Once these alarms confirm excessive leakage, the measured flow rate at the discharge of each ECCS pump is used to determine which train is faulted. The faulted train is then isolated.

Assuming none of the ND and NS room sump pumps are operating, the operator has at least 30 minutes from receipt of the high level alarm to isolate the passive failure and prevent the sump from overflowing. However, with only one of the four Nuclear Safety Related sump pumps operating, the pump down rate exceeds the leakage rate.

Consequently, this arrangement precludes all ECCS pump areas from flooding due to passive ECCS failures during long-term cooling.

For a description of leak detection features of the Liquid Radwaste System and its compliance with the requirements of IEEE 279-1971, refer to Section 7.6.7.

The design pressure of the suction lines for the charging and safety injection pumps is appropriate for all modes of ECCS operation.

The isolation valves (ND28A and NI136B) between the RHR pump discharge and the charging and safety injection pump suction lines are normally closed and interlocked to prevent opening until manual switchover to the recirculation mode. As indicated in Section 6.3.2.1.3 and Table 6.3.2-2, the interlocks that must be satisfied are:

1. The containment recirculation sump isolation valve is open.

2. The RHR pumps suction lines must be isolated from the Reactor Coolant System.

3. The safety injection pumps miniflow line must be closed.

In the recirculation mode, with the RHR pumps providing flow to the Reactor Coolant System, the safety injection pumps and charging pumps, there is no credible means of exceeding the design pressure.

440.126
(6.3)
(440.24)

Your response to Question 440.24 states that non-seismic piping which connects to the RWST is not required for safety related functions. The piping from safety injection pump miniflow line valve 147B to the RWST is non-seismic as well as connecting piping. This piping could fail due to the initiating accident event and degrade ECCS performance. Address this concern.

Response:

440.127
(15.0)
(440.56)

Your response to the steam generator tube rupture portion of Question 440.56 states: "Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the isolation procedure can be completed within 30 minutes of accident initiation. Included in this 30 minute time period would be an allowance of 5 minutes to trip the reactor and actuate the safety injection system (automatic actions), 10 minutes to identify the accident as a steam generator tube rupture and 15 minutes to isolate the faulted steam generator." This scenario is not consistent with Table 15.6.3-1, Steam Generator Tube Rupture Sequence of Events, which states the safety injection signal occurs at 773.0 seconds. Evaluate this discrepancy and show that adequate time is available for completion of operator action at 1800 seconds as indicated in Table 15.6.3-1.

Response:

The response to Question No. 440.56 and FSAR Section 15.6.3 have been revised. Please refer to these revisions in response to this question.

440.128
(15.3.3 &
15.3.4)
440.85 &
440.87

It is not apparent from your response to Questions 440.85 and 440.87 that you intend to analyze the locked rotor and shaft break transients consistent with the acceptance criteria in SRP 15.3.3 - 15.3.4 in NUREG-0800. We require that this event be analyzed assuming turbine trip and loss of offsite power to the undamaged pumps. The event should also be analyzed assuming the worst single failure of a safety grade system active component. Maximum primary system activity (in addition to activity from fuel failure resulting from the transient) and maximum steam generator tube leakage as allowed by the technical

specifications should be assumed. This analysis should demonstrate that offsite doses are less than 10 CFR 100 guidelines values. Any delay in the loss of offsite power assumption used for the analyses must be justified.

Response:

Accident Scenario

The locked rotor followed by a loss of offsite power transient is postulated to occur in the following manner:

a. Reactor coolant pump rotor locks (or shears) and flow in that loop begins coastdown.

b. The reactor is tripped on low RCS flow in one loop.

c. Turbine/Generator trips.

d. Offsite power is lost.

NOTE: Grid stability analyses show that the grid will remain stable and offsite power will not be lost because of a unit trip from 100% power. Refer to Section 8.2.2 and the response to Question 430.3. The following analysis assumes a 2 second time delay between reactor trip and loss of offsite power. This is a conservative assumption based on the grid stability analyses.

e. The loss of offsite power causes the three remaining reactor coolant pumps to coastdown.

Method of Analysis

The method of anlaysis used is the same as the cases presented in Section 15.3.3. The following case is analyzed;

Four loops operating, one rotor locks. Followed by coastdown of other three reactor coolant pumps.

Results

Figures Q440.128-1 through -5 show a comparison between the locked rotor transient without offsite power and the locked rotor transient with offsite power from Section 15.3.3. As can be seen from the figures, losing offsite power results approximately in the same peak clad temperature and the same peak RCS pressure.

The calculated sequence of events for the case without offsite power is shown in Table Q440.128-1.

Conclusion

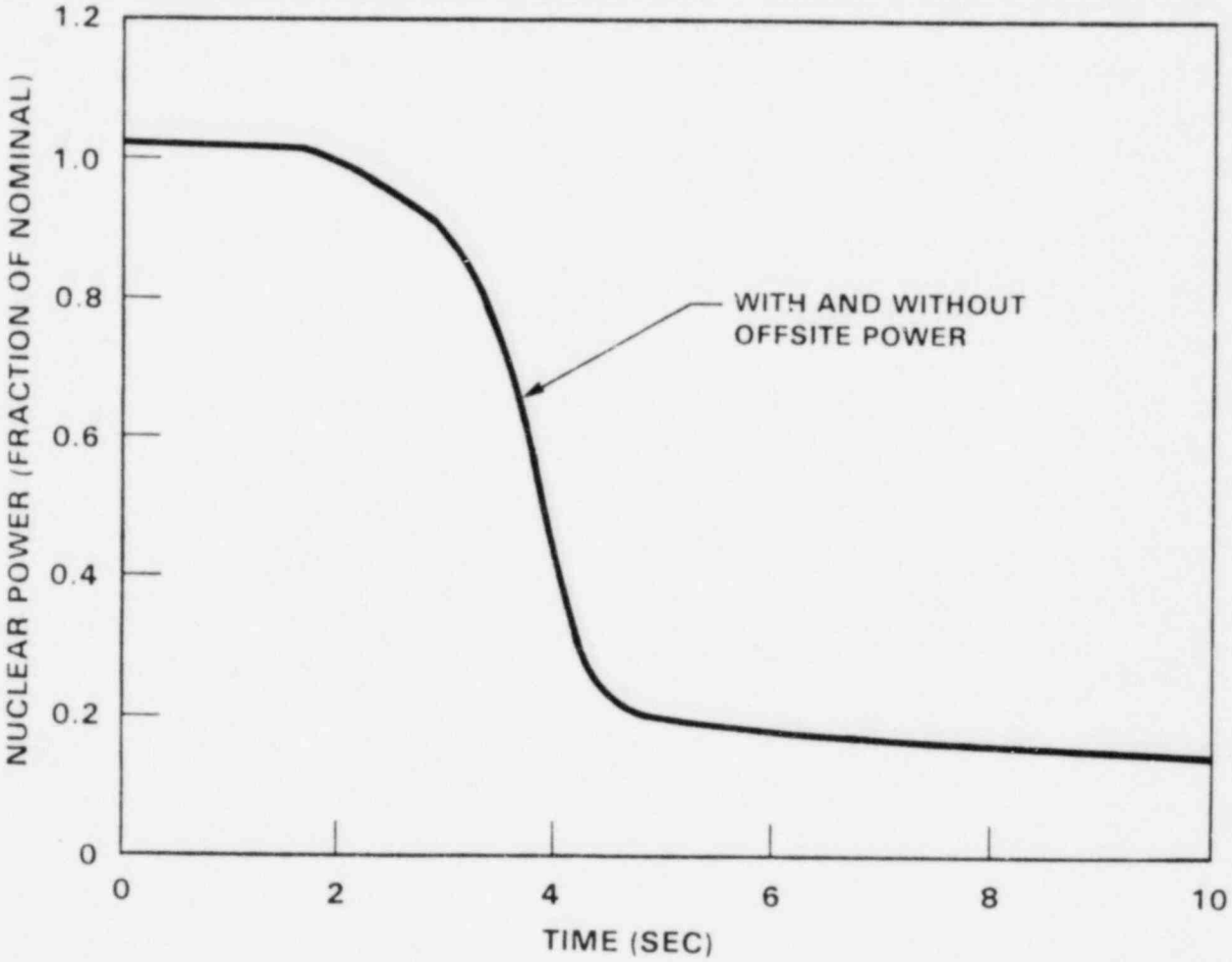
The locked rotor without offsite power transient is no more limiting than the case presented in Section 15.3.3.

TABLE Q440.128-1

SEQUENCE OF EVENTS

LOCKED ROTOR WITHOUT OFFSITE POWER

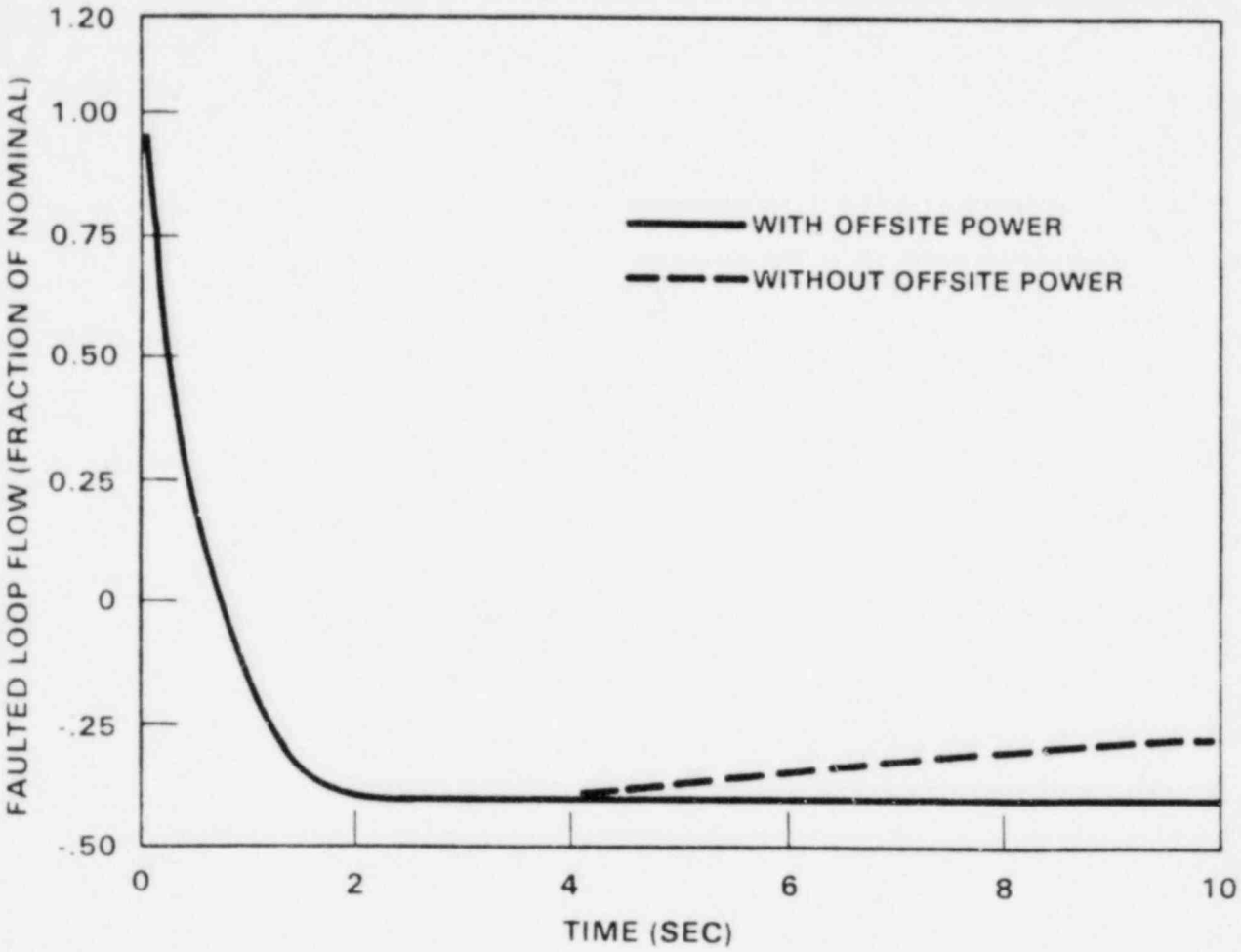
EVENT	TIME (SECONDS)
Rotor on one pump locks	0.0
Low RCS flow trip setpoint reached	.07
Rods begin to drop	1.07
Maximum clad temperature occurs	3.91
Remaining reactor coolant pumps begin to coastdown	3.07
Maximum RCS pressure occurs	4.40



NUCLEAR POWER TRANSIENT,
LOCKED ROTOR WITH AND
WITHOUT OFFSITE POWER

CATAWBA NUCLEAR STATION

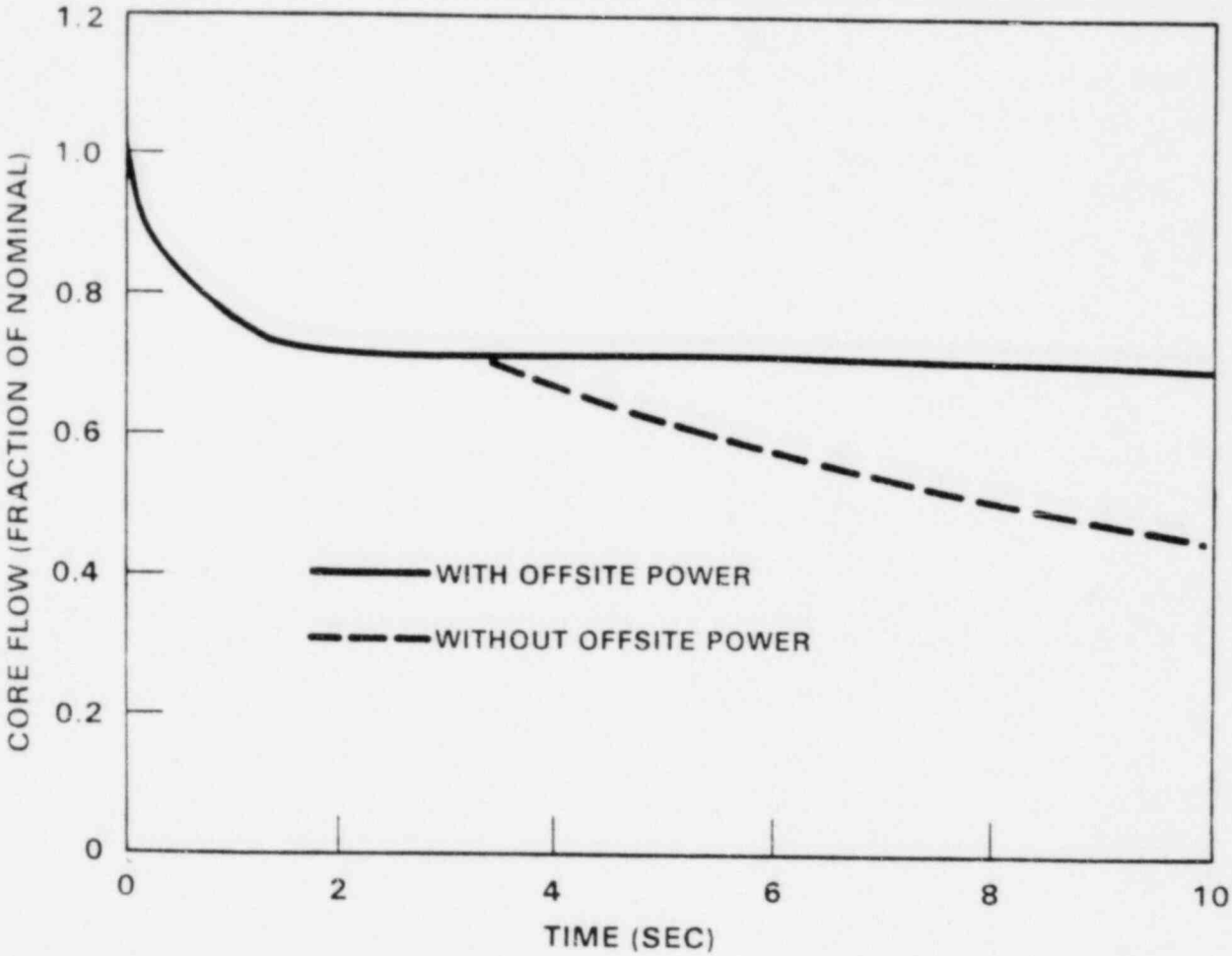
Figure Q440.128-1
Rev. 6



FAULTED LOOP FLOW TRANSIENT,
LOCKED ROTOR WITH AND
WITHOUT OFFSITE POWER

CATAWBA NUCLEAR STATION

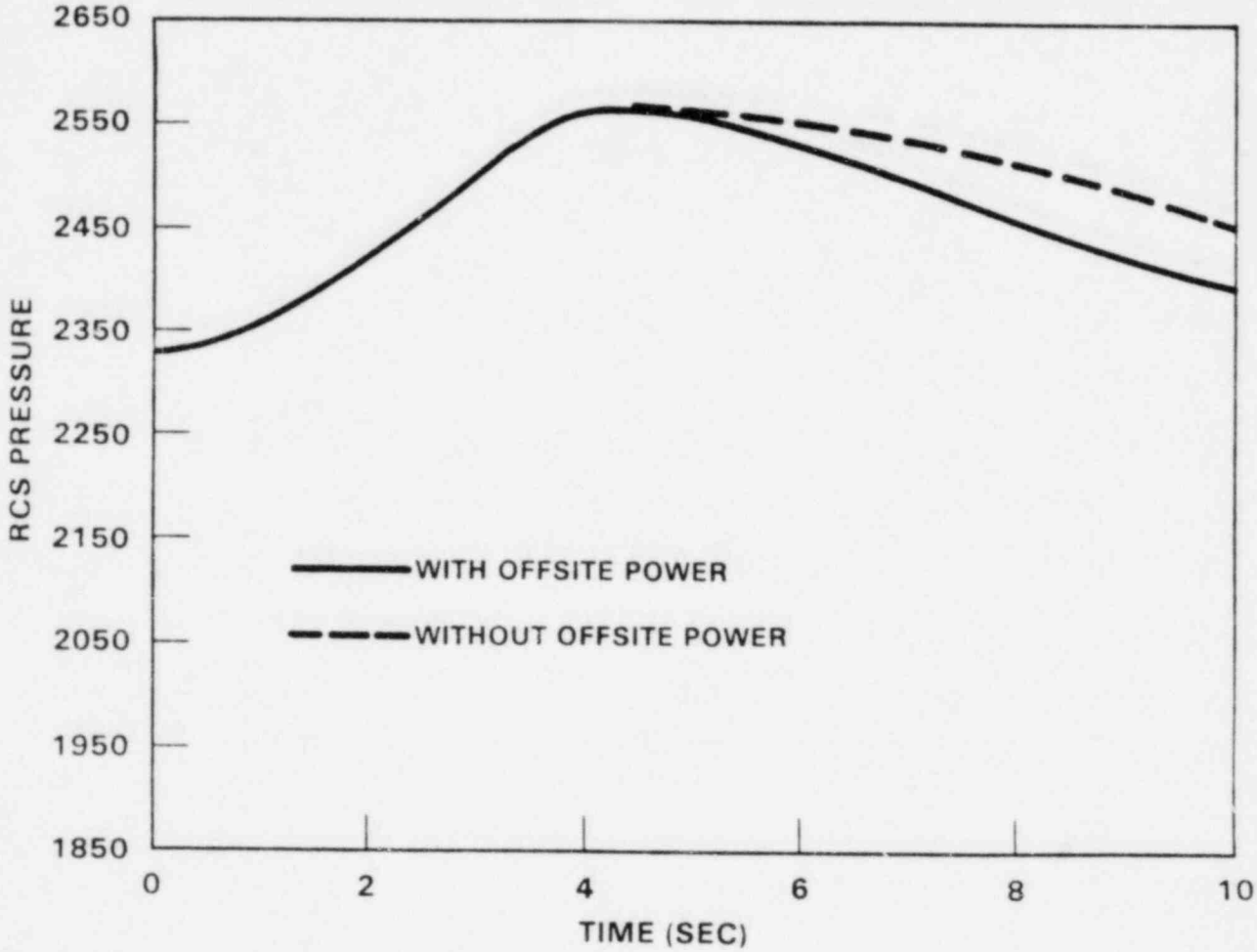
Figure Q440.128-2
Rev. 6



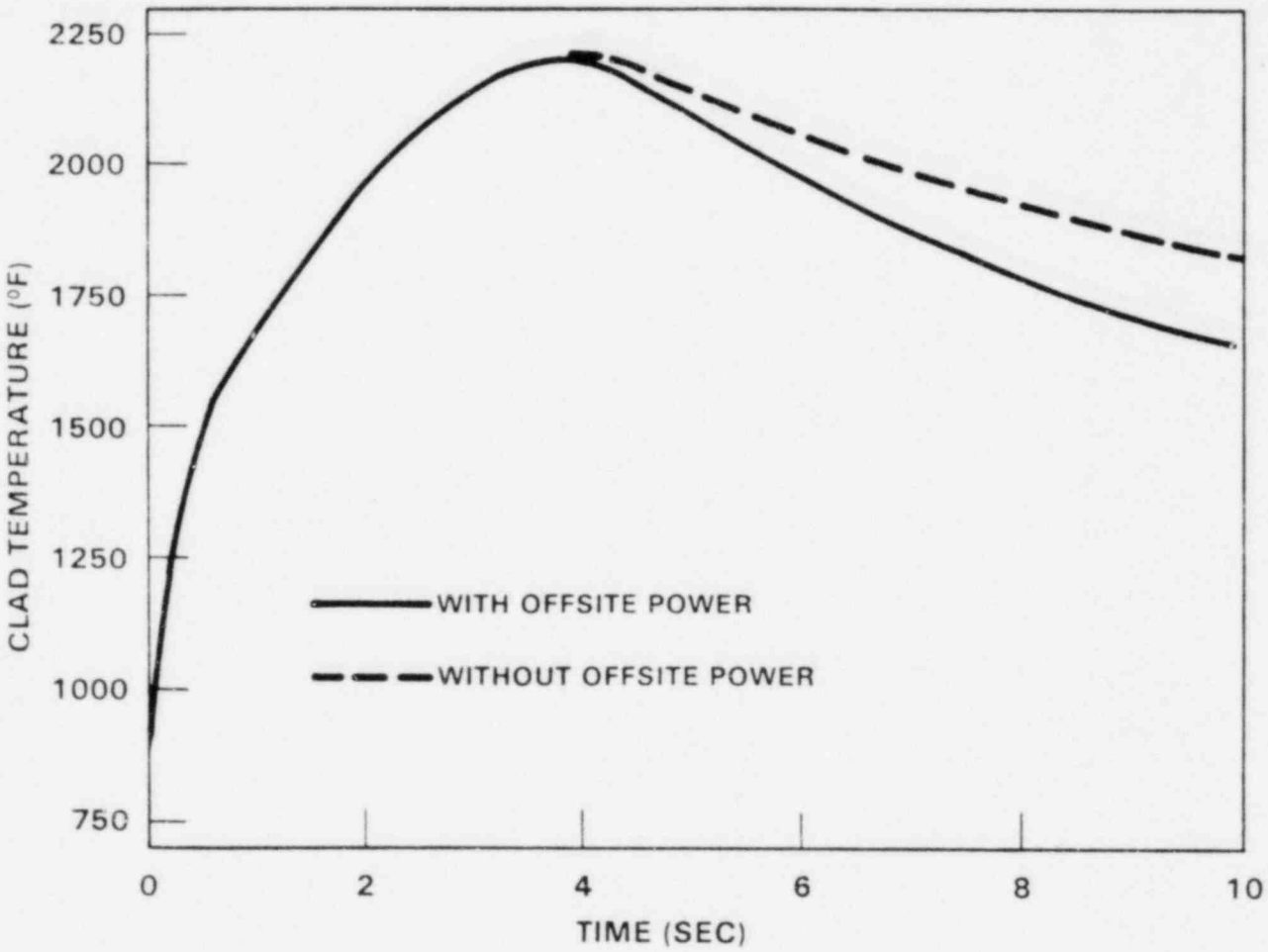
CORE FLOW TRANSIENT,
LOCKED ROTOR WITH AND
WITHOUT OFFSITE POWER

CATAWBA NUCLEAR STATION

Figure Q440.128-3
Rev. 6



RCS PRESSURE TRANSIENT,
LOCKED ROTOR WITH AND
WITHOUT OFFSITE POWER
CATAWBA NUCLEAR STATION
Figure Q440.128-4
Rev. 6



CLAD TEMPERATURE TRANSIENT, LOCKED ROTOR WITH AND WITHOUT OFFSITE POWER

CATAWBA NUCLEAR STATION

Figure Q440.128-5

Rev. 6

440.129
(15.6.5)
(440.100)

The acceptability of the responses to Questions 440.100 through 440.103 are dependent upon the response to Question 440.100 which asks for an explanation why the Catawba LOCA analysis spectrum identified a different limiting break case than analyses for previously reviewed UHI plants. Your response did not address the question. Explain clearly why (phenomenologically) Catawba analyses identified a double-ended cold leg guillotine rupture with a discharge coefficient of 1.0 as limiting, whereas analyses for other UHI plants have identified a break with a discharge coefficient of 0.6 as limiting for those plants. Alternately, provide plant-specific analyses to justify all sensitivities, per Appendix K and demonstrate that the model used to generate the analyses provided for Catawba meets the requirements of Appendix K.

Response:

The LOCA break spectrums performed for other plants equipped with UHI and standard 17 x 17 type fuel have identified a C_D = 0.6 DECLG break as the limiting case in terms of calculated peak clad temperature (PCT). Table 15.6.5-4 in Revision 5 of the Catawba FSAR, utilizing the optimized fuel design, identifies the C_D = 1.0 DECLG case to be limiting, with a calculated PCT of 2155°F. As indicated in Table 15.6.5-4 by an earlier hot rod burst time, cooling in the initial portion of the blowdown transient is demonstrably worse for the C_D = 0.6 DECLG case than for the C_D = 1.0 DECLG case. Other things being equal during the remainder of the LOCA transient, the C_D = 0.6 DECLG case would indeed become limiting.

In Table Q440.129-1 the calculated clad temperature transients at the 5.5 ft. core elevation are compared for the C_D = 0.6 DECLG cases of Table 15.6.5-4. Confirming the behavior indicated by the hot rod burst times, the C_D = 0.6 DECLG case exhibits a higher calculated clad temperature at 5.5 ft. at 70 seconds. However, by 100 seconds the C_D = 1.0 DECLG case has become limiting. The earlier indication that the C_D = 0.6 DECLG case would be limiting for Catawba has not come to pass. In particular, during the time interval from 86-100 seconds the clad temperature rise at the 5.5 ft. elevation is almost twice as great for the Catawba C_D = 1.0 DECLG case as for the C_D = 0.6 DECLG break.

The reason the calculated clad temperature rise is so great in the C_D = 1.0 DECLG case can be found in Table Q440.129-2, which presents fuel cladding to fluid heat transfer coefficients. During much of the 86-100 second time span the specified heat transfer coefficient is the model-imposed limit of 1.0 Btu/hr-sq.ft.-°F, leading to extensive clad heatup. The value of 1.0 is specified for heat transfer occurring in the low pressure UHI countercurrent flow regime (NUREG-0297, p. 4-21).

In contrast, the heat transfer coefficients for the same time interval are much greater for the C_D = 0.6 DECLG case, as presented in Table Q440.129-3. Table Q440.129-3 coefficients are being computed for low pressure cocurrent flow in the hot assembly by applying the Dougall-Roshenow relationship to the steam portion of that flow. In both breaks considered herein net total flow thru the 17 x 17 optimized fuel hot assembly at core midplane is predicted to be basically upwards during the time period after 86 seconds until the end of blowdown occurs. The influence of the break is of couse greater for the C_D = 1.0 DECLG case; counter current flow is predicted to occur in the hot assembly. As a consequence of this flow condition being calculated a minimal coefficient is assigned for heat transfer in the C_D = 1.0 DECLG case, causing the C_D = 1.0 DECLG break to conservatively predict a very high clad heatup rate between 86-100 seconds for the 17 x 17 optimized fuel. This in turn causes the C_D = 1.0 DECLG break to surpass the C_D = 0.6 DECLG case in calculated PCT and become limiting.

In summary, the Catawba Units are different in design from any of the other Westinghouse plants equipped with UHI; included among the differences is Catawba's use of 17 x 17 optimized fuel. A spectrum of discharge coefficients is analyzed in all Westinghouse large break ECCS performance analyses in order to identify the limiting break for the particular plant under review. Non-UHI four-loop plants have historically demonstrated different limiting discharge coefficients among themselves. In fact, each discharge coefficient analyzed for the DECLG break (1.0, 0.8, 0.6, 0.4) in large break LOCA evaluation model analyses has at some time since 1974 been calculated to be the limiting case break for one or more Westinghouse non-UHI four-loop plants. Inasmuch as differences in design among Westinghouse non-UHI four-loop plants lead to different discharge coefficients being predicted to be limiting, it is not surprising that a similar condition would arise among four-loop plant equipped with UHI.

TABLE Q440.129-1

CALCULATED CLAD TEMPERATURES AT THE 5.5 FT. FORE ELEVATION

Transient time, sec.	C_D = 1.0 DECLG value, °F	C_D = 0.6 DECLG value, °F
70	1605	1642
80	1677	1699
86	1807	1807
90	1886	1849
100	2054	1938

TABLE Q440.129-2 (Page 1)

CALCULATED HEAT TRANSFER COEFFICIENTS AT

THE 5.5 FT. CORE ELEVATION, C_D = 1.0 DECLG

Transient time, sec.	Heat Transfer Coefficient Btu/hr-sq. ft-°F
77.700	1.4058404E+01
78.100	1.8299229E+01
78.500	1.4301176E+01
78.900	1.3983083E+01
79.300	9.5102553E+00
79.700	7.0024680E+00
80.100	6.8444286E+00
80.500	4.6061513E+00
80.900	3.8610819E+00
81.300	3.7599394E+00
81.700	3.8095824E+00
82.100	3.7330178E+00
82.500	3.5043216E+00
82.900	3.4164776E+00
83.300	2.8750738E+00
83.700	3.7460032E+00
84.100	6.7254929E+00
84.500	5.8232633E+00
84.900	5.0595152E+00
85.300	3.3095198E+00
85.700	1.0000000E+00
86.100	1.0000000E+00
86.500	1.0000000E+00
86.900	1.0000000E+00
87.300	1.0000000E+00
87.700	6.2787167E+00
88.100	1.0000000E+00
88.500	1.0000000E+00
88.900	1.0000000E+00

TABLE Q440.129-2 (Page 2)

CALCULATED HEAT TRANSFER COEFFICIENTS AT

THE 5.5 FT. CORE ELEVATION, C_D = 1.0 DECLG

Transient time, sec.	Heat Transfer Coefficient Btu/hr-sq. ft-°F
89.300	5.6608425E+00
89.700	1.0000000E+00
90.100	6.2017441E+00
90.500	4.0534494E+00
90.900	4.5685645E+00
91.300	1.0000000E+00
91.700	1.0000000E+00
92.100	1.0000000E+00
92.500	1.0000000E+00
92.900	1.0000000E+00
93.300	1.0000000E+00
93.700	1.0000000E+00
94.100	5.5320796E+00
94.500	5.4283854E+00
94.900	6.2664910E+00
95.300	6.8124050E+00
95.700	4.4143729E+00
96.100	1.5202209E+00
96.500	1.786957E+00
96.900	4.7937900E+00
97.300	6.1769207E+00
97.700	3.4296826E+00
98.100	1.0000000E+00
98.500	1.0000000E+00
98.900	3.9853799E+00
99.300	6.2220212E+00
99.700	1.0991671E+01

TABLE Q440.129-2 (Page 3)

CALCULATED HEAT TRANSFER COEFFICIENTS AT

THE 5.5 FT. CORE ELEVATION, C_D = 1.0 DECLG

Transient time, sec.	Heat Transfer Coefficient Btu/hr-sq. ft-°F
100.100	8.7595340E-01
100.500	1.0000000E+00
100.900	1.0000000E+00
101.300	1.0000000E+00
101.700	7.9946497E+00
102.100	1.0211885E+00
102.500	4.7168455E+00
102.900	1.0445269E+01
103.300	5.4248848E+00
103.700	1.0953836E+01
104.100	7.8200531E+00
104.500	8.1481942E+00
104.900	5.1232042E+00
105.300	4.6474613E+00
105.700	5.9071994E+00
106.100	1.0717609E+01
106.500	6.1903476E+00

TABLE Q440.129-3

CALCULATED HEAT TRANSFER COEFFICIENTS AT THE 5.5 FT. CORE ELEVATION, C_D = 0.6 DECLG

Transient time, sec.	Heat Transfer Coeff., BTU/hr-sq.ft.-°F
80.1	10.
82.1	10.
84.1	16.
86.1	15.
88.1	4.7
90.1	6.4
92.1	10.6
94.1	7.
96.1	15.
98.1	10.6
100.1	25.
102.1	16.2

440.T.0 REACTOR SYSTEMS BRANCH

440.T.1 (1.9) In response to NUREG-0737 item II.B.1, Catawba FSAR Section 1.9 states that a description of the reactor vessel head vent system will be provided "later." We require that this description be provided for our review.

Response:

See revised Table 1.9-1, Item II.B.1.

440.T.2 (1.9) In response to NUREG-0737 item II.K.2.13 (Thermal-Mechanical Report), Catawba FSAR Section 1.9 states that a report will be provided, but does not provide a schedule for this submittal. We require the applicant to either provide a submittal schedule consistent with the requirements of NUREG-0737 or cite an applicable generic report whose submittal schedule complies with NUREG-0737 requirements.

Response:

See revised Table 1.9-1, Item II.K.2.13.

440.T.3 (1.9) In response to NUREG-0737 item II.K.3.2, Catawba FSAR Section 1.9 has referred to a Westinghouse Owners Group report. We require that the applicant either provide a submittal schedule consistent with the requirements of NUREG-0737 or identify the specific reference which applies to Catawba.

Response:

See revised Table 1.9-1, Item II.K.3.2.

440.T.4 (1.9) In response to NUREG-0737 item II.K.3.3 the applicant has not committed to report RV and SV challenges annually as required by NUREG-0737. We require the applicant to provide a plan to report these challenges annually.

Response:

See revised Table 1.9-1, Item II.K.3.3.

440.T.5 In response to NUREG-0737 item II.K.3.10 the applicant has proposed to bypass the anticipatory reactor trip on turbine trip at low power levels (below 50%). We require that he provide analyses to justify the power level at which the trip is bypassed (P-8).

Response:

An analysis was transmitted by letter of July 26, 1982 from W. O. Parker, Jr., to H. R. Denton which demonstrated the acceptability of bypassing the reactor trip on turbine trip at power levels below 70%.

440.T.6 In response to NUREG-0737 item II.K.3.17 the applicant has committed to report ECCS outages, but has not described what information would be reported. We require that the applicant commit to include in the report the information specified in NUREG-0737.

Response:

See revised Table 1.9-1, Item II.K.3.17.

440.T.7 (5.4.12) (II.B.1) (440.T.1) We require the following additional information concerning High Point Vents:

(a) Table 1.9-1 Item II.B.1, RCS Vents, states that the system design appears on Figures 5.1-1 and 5.1-2. Provide a more legible schematic design of the vent system with identification of each valve by the valve number.

(b) Provide information on the following items, which apply to the vent system up to and including the second normally closed valve:

1. the design temperature and pressure of piping, valves and components.

2. Verify that the piping, valves, components and supports are classified Seismic Category 1 and Safety Class 2 (or Safety Class 1 for those parts upstream of the flow restricting orifice).

(c) Submit (or reference) Operating Guidelines for use of the RCS Vent System. The guidelines shall include:

1. Methods for the operator to determine when to initiate and terminate venting, and the instrumentation needed for this determination. The guidelines should cover a wide variety of initial conditions and should consider the balance between the need for increased core cooling versus the decreased containment integrity due to increased hydrogen concentrations.

2. Detailed methods for determining the size and location of a noncondensible gas bubble.

3. Methods which may be used to vent the steam generator U-tubes.

(d) Describe the equipment used to vent the pressurizer and verify that this equipment meets the clarification requirements of NUREG-0737 Item II.B.1.

(e) What type of valve and operator is used in the head vent system? If these valves fail in position, describe how irreversible vent operation can be prevented.

Response:

(a) See Figure Q440.T.7-1

(b) 1. Design Pressure - 2500 psia
Design Temperature - 650°F

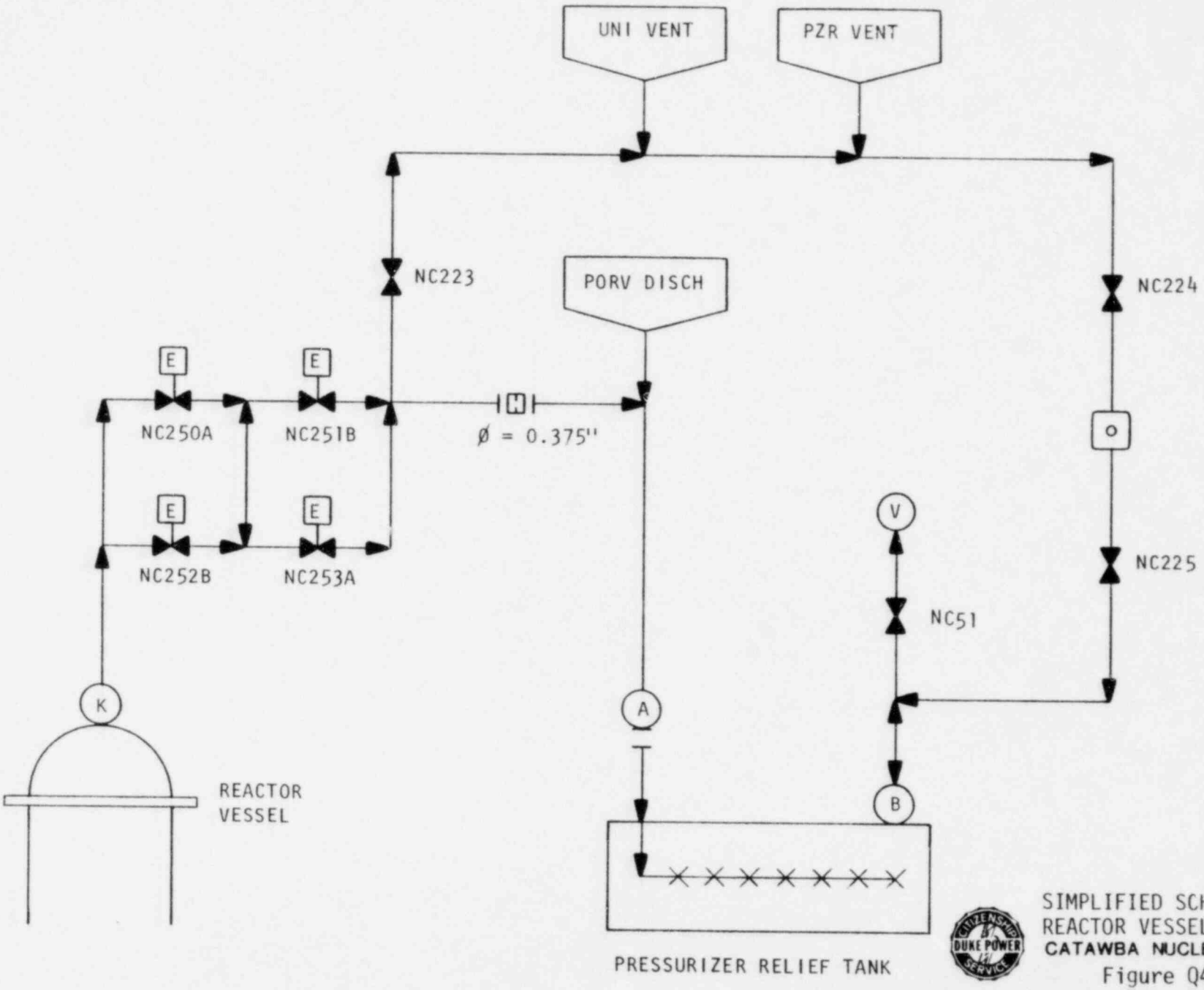
2. Piping, valves, components and supports are classified Seismic Category I and Safety Class 1 up to and including the second normally closed valve; Safety Class 2 up to and including the flow-restricting orifice.

(c) The Westinghouse Owners Group has prepared "Emergency Response Guidelines (ERG's)" in response to NUREG-0737, Item I.C.1 which were submitted for NRC review (Letter OG-61 dated July 7, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to Stephen H. Hanauer (NRC)). The ERG's provide criteria for use of the RCS Vent System. Once approved, the ERG's will be used in developing the Catawba Emergency Procedures.

(d) The power-operated relief valves (PORV's) are used to vent the pressurizer; PORV's meet the clarification requirements of NUREG-0737, II.B.1.

(e) Head vent isolation valves are Kerotest Y-body globe valves with electric motor operators. Valves NC252B and NC253A are

in the closed position with power removed during normal operation. Venting is accomplished by opening valves NC250A and 251B in series. A single failure would affect only one of the two powered valves and venting would be terminated by closing the other.



SIMPLIFIED SCHEMATIC OF
REACTOR VESSEL HEAD VENT SYSTEM
CATAWBA NUCLEAR STATION
Figure Q440.T.7-1
Rev. 6

440.T.8
(1.9)
(440.T.2)

In response to NUREG-0737 Item II.K.2.13 (Thermal-Mechanical Report), Catawba FSAR Section 1.9 states a generic analysis is applicable to to Catawba. We require a specific reference describing the analysis and a justification of the applicability of the reference.

Response:

See the revised response to Item II.K.2.13.

440.T.9
(1.9)
(440.T.6)

In response to NUREG-0737 Item II.K.3.17 (Report on Outages of ECCS...), Catawba FSAR Section 1.9 states a (reporting) plan will be developed prior to full-power operation. We require that it be developed before receipt of an operating license.

Response:

See the revised response to Item II.K.3.17.