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SUBJECT: Withdraws proposed license amend dtd 970904.RAI response to TS change 96-10 included.

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W. R. McCollum, Jr.
Vice President

February 9, 1998

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
High Pressure Injection System Requirements
Response to Request For Additional Information
Technical Specification Change # 96-10

On March 31, 1997, Duke Energy Corporation (Duke) submitted proposed Technical Specification changes for the High Pressure Injection (HPI) System. This submittal was made to address deficiencies in the current HPI Technical Specifications. A proposed license amendment was also submitted on September 4, 1997, to justify the acceptability of the current Technical Specification for the HPI System and allow operation at reduced power levels with two HPI pumps. This submittal was made because of the potential for an extended shutdown to repair the 3B HPI pump. The 3B HPI pump has been repaired and Duke believes that further efforts to resolve the HPI Technical Specification deficiencies should focus on the March 31, 1997 submittal. As such, Duke withdraws the proposed license amendment dated September 4, 1997.

In a letter dated October 1, 1997, the staff requested additional information to support the review of the September 4, 1997, Duke submittal. The staff's questions are also relevant to the review of the March 31, 1997, Duke submittal. Therefore, Duke felt it would be beneficial to respond to these questions to support the review of the March 31, 1997, proposed Technical Specification changes for the HPI System. Please find attached Duke's response to this request for additional information.

Resolution of the current HPI Technical Specification deficiencies is necessary to support Oconee Nuclear Station's conversion to Improved Technical Specifications.

A001/1

Please address any questions to J. E. Burchfield, Jr. at (864) 885-3292.

Very Truly Yours,

W. R. McCollum
Site Vice President
Oconee Nuclear Station

Attachment

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Project Manager

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Regional Administrator, Region II

M. A. Scott
Senior Resident Inspector

Attachment
Response to Request for Additional Information

Question 1: The manual atmospheric dump valves (ADVs) are credited in the loss-of-coolant accident (LOCA) analysis, and as a result, should be included in the technical specifications. Controlling the operability requirements in a license commitment is not sufficient. The failures of these valves in the context of a single failure analysis should also be described. The modeling of these valves needs to be described and linked to the operability requirements in the technical specifications (TS). If the accident analysis models two of two valves, then inoperabilty of one valve puts the plant beyond design basis and the allowed outage time (AOT) should be very short. The AOT should be consistent with the AOT associated with the high pressure injection (HPI) system. Use of specifications similar to those in the standard TS is not appropriate because the standard TS do not consider the use of the ADVs to function to mitigate the consequences of a LOCA.

Response:

Duke has elected to withdraw the proposed license amendment of September 4, 1997 regarding the HPI System. Therefore, the portion of Question 1 regarding controlling operability of the ADVs through a selected licensee commitment is no longer applicable. However, the remainder of the question regarding the basis of the proposed ADV Technical Specifications submitted on March 31, 1997, is addressed in this response.

Since the time of the March 31, 1997, and September 4, 1997, submittals, Duke has obtained revised LOCA analyses from Framatome Technologies, Inc. These analyses include sensitivity studies to bound the different fuel assembly designs and quantify previous engineering judgments regarding the importance of the secondary side heat transfer boundary conditions. The small break loss of coolant accident (SBLOCA) break spectrum analyses model flow initiating through the ADVs on both main steam lines (i.e. one flow path on each steam generator) within 55 minutes of the Engineered Safeguards (ES) signal for the 100% FP cases that credit two operable HPI pumps. For the 100% FP break spectrum, operator action to raise steam generator levels to the loss of subcooled margin setpoint are credited on the first generator at 20 minutes after the ES signal and on the second generator at 30 minutes after the ES signal.

For the SBLOCA cases from 75% FP that credit only one HPI pump, flow through the ADV is initiated on only one steam generator at 25 minutes after the ES signal. Operator action to increase steam generator level on this steam generator to the loss of subcooled margin setpoint is credited at 20 minutes after the ES signal. In the SBLOCA analyses, the steam generators are supplied with hotter main feedwater until the natural circulation setpoint is reached, and then cooler emergency feedwater is used to raise the levels to the loss of subcooled margin setpoint. This has been confirmed to be the conservative assumption relative to feedwater supply, mainly due to the hotter main feedwater. The assumption of continued MFW flow is conservative in that the assumed loss of offsite power (LOOP) would result in a loss of MFW at the beginning of the event.

In order to assess the significance of steaming only one steam generator for the full power cases, a sensitivity analysis was performed for the limiting 0.15 ft^2 break. This sensitivity case also assumed that emergency feedwater (EFW) was only supplied to one steam generator, following a loss of MFW at time zero. This loss of MFW assumption is consistent with the need for evaluating EFW to only one SG, since if MFW is available both steam generators could be supplied with feedwater. The analysis results show that the peak cladding temperature did not increase with only one steam generator being supplied with emergency feedwater and steamed. It is therefore concluded that whether or not the ADVs on one or both steam generators are steamed does not have a significant effect on the SBLOCA results. Therefore, the technical specifications proposed for the ADVs are appropriate.

The importance of the ADVs for mitigating the LOCAs of interest is not the same as the importance of the HPI System. The need for the ADVs is based on an assumed single failure in the HPI System as well as the assumed unavailability of the Turbine Bypass System. The frequency of sequences with failures of these systems would be low. The additional SBLOCA analyses performed by FTI which credit operator actions to improve heat transfer to only one steam generator are quite conservative in that they assume two failures. The first failure is one train of HPI and the second failure is the inability to open the ADVs on one steam generator. Thus, these cases go beyond the requirements of the licensing basis in that only one single failure needs to be postulated. If a single failure of the ADVs is postulated, the full complement of the HPI System would be available to mitigate the accident. Therefore,

these additional analyses demonstrate that the proposed Technical Specifications for the ADVs are appropriate. It is Duke's position that the proposed Technical Specifications for the atmospheric dump valves provide administrative controls commensurate with the importance of these valves to plant safety.

Question 2: Discuss the safety and seismic classification of the ADVs, the other valves needed for the ADVs to function (the block, throttle, isolation, and small pressure equalization valve), and the down stream piping. If they are not safety-related or seismic, explain why they are not needed to be and why they will be available following a design basis accident. The explanation should include a discussion of why this change will not violate the plant licensing basis, the applicable regulations, the applicable design criteria, and the applicable regulatory guidance.

Response:

During a SBLOCA, the Atmospheric Dump Valves must open to depressurize the steam generators. This is accomplished by opening a bypass valve, a block valve, then a throttle valve. The bypass and block valves and their associated piping are QA-1 and seismic, as they form the boundary of the Main Steam line. The piping downstream of the block and bypass valves is classified as non-QA. Neither the throttle valve nor its associated piping are QA or seismic. This categorization is consistent with the original design and licensing basis of the plant. Chapter 3.1.1 of the UFSAR describes the structures, systems, and components required to be QA-1 at ONS. The basis of this list is somewhat different than many other licensees in that the list was not directly generated based on functional definitions. In other words, one cannot assume a QA classification based on function. This somewhat unique definition of QA at Oconee was explained in a Duke submittal to the staff dated April 12, 1995, and confirmed in an SER from the NRC to Duke dated August 3, 1995.

The UFSAR also provides guidance on the seismic requirements. Chapter 3.2.2 states, …"A maximum hypothetical earthquake will not result in a loss-of-coolant accident (LOCA), but the simultaneous occurrence of these events will not result in loss of function to vital safety related components or systems. The simultaneous occurrence of the maximum hypothetical earthquake and a LOCA is only a design criteria. A LOCA is not postulated to occur simultaneously with a maximum hypothetical earthquake during

accident analysis". A December 5, 1994 letter from the NRC to Duke reiterates this position by stating "a seismic event or an independent pipe break is not postulated to occur concurrently with a LOCA." In summary, all equipment designated as safety-related is designed seismically. Since the ADVs are not safety-related, they are not required to be seismically designed. However, a LOCA and seismic event are not postulated to occur simultaneously; therefore, the ADVs will be able to function during the SBLOCA.

In order to help assure the valves will be available when required, they are full stroke tested on a refueling basis as part of Oconee's supplemental valve testing program. Every fifth refueling an actual steam flow test is conducted to assure throttle valve controllability. As an aside, it should be noted that these valves are included on Oconee's SQUG safe shutdown equipment list and have been successfully evaluated as being able to survive and operate after an earthquake.

As described in the response to Question 1, the SBLOCA analyses to support the proposed HPI and ADV Technical Specifications are conservative in that assumptions beyond the single failure criterion are imposed. The SBLOCA analyses assume a single failure of one train of HPI and also only credit blowdown via one steam generator. Thus, the analyses presented in response to Question 1 actually incorporate two failures. The fact that the Technical Specifications will require the ADV flow path on each steam generator to be operable is appropriate and assures that the required equipment to mitigate a SBLOCA will be available.

Question 3: The new accident analysis using the new LOCA methodology, BAW-10192P-A, should be described in some detail with explicit explanation of how the use of the methodology is in conformance with the code restrictions and limitations. All of the emergency core cooling system acceptance criteria should be discussed in the submittal (not just the peak centerline temperature). Additionally, a discussion of the spectrum of breaks that were analyzed for both one HPI and two HPI operation should be described in detail. The limiting break for each case should be identified with a justification provided that includes a technical discussion that the limiting break has been identified and analyzed (please pay particular attention to the HPI injection line break). The single failures chosen should be described and justified for the different scenarios (one pump operation, two pump operation, etc.) and a description of the assumptions associated with loss of

offsite power and reactor coolant pump operation should be provided. Using the results of the old and new analysis, try to estimate the margin or benefit gained by applying the new code.

Response:

The new SBLOCA analyses use the RELAP5-based Evaluation Model of BAW-10192-P. The NRC SER for this topical report included twelve restrictions as described in Section 6 of the SER. Framatome Technologies, Inc. has evaluated each of these restrictions during the Oconee SBLOCA reanalysis project and has confirmed that all of these restrictions except one have been addressed in the plant-specific Oconee LOCA calculations or in generic studies for the Oconee-class plants. The remaining item (Restriction 3), concerns the radial and axial core power peaking factors used in core reload design, and how they are supported by the values assumed in the LOCA analysis. Since Duke performs the reload core design for Oconee, this restriction was assessed by Duke with input from Framatome Technologies, Inc. It was confirmed that the core power peaking factors used in the reload design are consistent with the LOCA analysis and the SER restriction. Therefore, all of the NRC SER restrictions have been addressed.

All of the 10 CFR 50.46 LOCA acceptance criteria were met for the Oconee SBLOCA analyses. The limiting PCTs, which were well within the 2200°F limit, are provided in the table below. The SBLOCA local cladding oxidation is confirmed to be less than the 17% limit. The calculated SBLOCA hot channel oxidation is less than 1%, which ensures that the whole core oxidation is less than 1%. The consequences of both thermal and mechanical deformation of the fuel assemblies in the core have been assessed, and the resultant deformations have been shown to maintain coolable core configurations. The long-term cooling of the core is ensured by maintaining ECCS flow in excess of the decay heat load, and by preventing boric acid precipitation via establishing a long-term boron concentration control process. The Oconee ECCS design and emergency operating procedures accomplish the long-term cooling function, and meet this acceptance limit.

The full power, two HPI pump, SBLOCA analyses include cold leg pump discharge breaks (0.04, 0.07, 0.1, 0.125, 0.15, 0.175, 0.2, 0.3, 0.5, and 0.75 ft^2), and the special cases of the 0.44 ft^2 core flood line break and the 0.025 ft^2 HPI line break. The limiting full power case is identified as the 0.15 ft^2 break with a PCT of 1369°F. The 75% power, one

HPI pump, SBLOCA analyses include cold leg pump discharge breaks (0.04, 0.065, 0.07, 0.075, 0.08, 0.10, and 0.20 ft^2). The limiting case is identified as the 0.07 ft^2 break with a PCT of 1862°F. The fineness of these break spectrums is sufficient for identifying the limiting break sizes. A break size of 0.01 ft^2 for the full power and 75% FP cases has also been evaluated and is non-limiting.

A loss of offsite power is assumed to occur at the time of reactor trip. The reactor coolant pumps are assumed to begin to coast down at the time of reactor trip. The single failure chosen minimizes the delivered ECCS flow. This assumption involves a power supply failure (4160 V switchgear TC, TD, or TE) that results in only one HPI pump supplying two cold legs initially, with the SBLOCA occurring on one of these two cold legs.

A specific comparison between SBLOCA results from the old (CRAFT-based) and new (RELAP5-based) Evaluation Models is not available. In addition to the differences between codes, a large number of initial and boundary condition assumptions have been revised in the new analyses. In general it can be stated that the combination of the code and assumption changes has resulted in a longer period of core uncovery and higher PCTs for SBLOCAs.

The following table provides the results of the full power and reduced power break spectrums using the RELAP5-based Evaluation Model:

Break Size (ft^2)	Initial Power Level (%)	Time of RPS trip (sec)	Time of ES signal (sec)	Transient End Time (sec)	Time of manually aligning HPI trains	Time to initiate raising SG1 level to 95%	Time to open ADVs on the first SG	PCT (°F)
0.44, core flood line	100	0.3201	8.68	700	ES+10 min.	**Note 1**	**Note 4**	715 *(Nov. 1994)*
0.025, HPI line	100	38.30	70.04	6400	ES+10 min.	ES+20 min. **Note 5**	ES+55 min. **Note 4**	715 *(Nov. 1994)*
0.04	100	22.88	47.98	2617	ES+10 min.	ES+20 min. **Note 5**	**Note 4**	715 *(Nov. 1994)*

0.07	100	11.96	30.62	1589	ES+10 min.	ES+20 min.	**Note 4**	715
0.1	100	7.28	22.76	1468	ES+10 min.	ES+20 min.	**Note 4**	1339
0.125	100	5.20	19.26	1188	ES+10 min.	**Note 1**	**Note 4**	1362
0.15	100	3.78	16.44	1000	ES+10 min.	**Note 1**	**Note 4**	1369
0.175	100	2.76	14.54	865	ES+10 min.	**Note 1**	**Note 4**	1322
0.2	100	1.96	13.32	794	ES+10 min.	**Note 1**	**Note 4**	1275
0.3	100	0.640	10.46	499	**Note 1**	**Note 1**	**Note 4**	1141
0.5	100	0.260	8.08	258	**Note 1**	**Note 1**	**Note 4**	931
0.75	100	0.160	6.84	204	**Note 1**	**Note 1**	**Note 4**	985
0.44	65 **Note 3**	0.32	3.76	1200	**Note 2**	ES+20 min.	ES+30 min. **Note 3**	715 *(Jan. 1995)*
0.025	65 **Note 3**	38.0	64.62	2000	**Note 2**	ES+20 min.	ES+30 min. **Note 3**	715 *(Jan. 1995)*
0.04	75	23.46	42.80	1700	**Note 2**	ES+20 min.	ES+25 min.	715
0.065	75	13.62	26.84	1700	**Note 2**	ES+20 min.	ES+25 min.	1669
0.07	75	12.48	24.90	1700	**Note 2**	ES+20 min.	ES+25 min.	1862
0.075	75	11.46	23.24	1700	**Note 2**	ES+20 min.	ES+25 min.	1761
0.08	75	10.54	21.84	1700	**Note 2**	ES+20 min.	ES+25 min.	1696
0.10	75	7.80	17.62	1700	**Note 2**	ES+20 min.	ES+25 min.	1619
0.20	75	2.30	10.24	720	**Note 2**	**Note 1**	**Note 4**	1224

The RELAP5 CFT and HPI line break analyses at 100%FP performed in Nov. 1994 were bounding and were not reanalyzed. CFT and HPI line break analyses at 65%FP were bounding and were not reanalyzed at 75%FP.

Note 1: These cases were terminated prior to the raising on SG1 level to 95% OR and/or the time to open the ADVs. The transients were terminated because the peak cladding temperature had been determined and appropriate long-term cooling had been assured.

Note 2: For 75%FP analyses, only one HPI pump is modeled at ES+48 seconds.

Note 3: The RELAP5 CFT and HPI line break analyses at 65%FP bound the 75%FP cases assuming that ADV blowdown occurs at ES+25 minutes.

Note 4: For the 100%FP analyses, the ADVs are opened on one or both steam generators such that a 50°F/hr cooldown rate is maintained. However, the transient analyses at 100%FP for all break sizes except the HPI line break were terminated prior to the opening of the ADVs. For the 75%FP analyses, the ADVs were opened only on the first steam generator. For the 0.20 ft^2 break at 75%FP, the transient was terminated prior to the opening of the ADVs.

Note 5: The raising of SG2 level to 95% OR is modeled at ES+30 minutes.

Question 4: To be clear what methodologies are being used for which LOCA applications, please provide a table and indicate what methodologies are being used for large breaks (with the sizes) and small breaks (with sizes and locations) and reference them in the TS. Verify that the Core Operating Limits Report references or the TS administrative controls references do not need to be changed with the change in the LOCA methodology.

Response:

The UFSAR markups submitted on September 4, 1997, which are being withdrawn, implemented the RELAP5-based SBLOCA Evaluation Model and analyses, while maintaining the CRAFT-based LBLOCA Evaluation Model and analyses. The UFSAR will be updated upon approval of the March 31, 1997, proposed Technical Specification changes. The RELAP5-based LBLOCA reanalyses were recently completed, but UFSAR markups were not submitted since they are not required for this proposed technical specification revision. However, the RELAP5 LBLOCA UFSAR revisions will be included in the next update of the UFSAR. The transition break size between large and small breaks is 0.75 ft^2 for the RELAP5-based Evaluation Model. The RELAP5 Evaluation Model for both large and small break LOCAs is BAW-10192-P, "BWNT Loss-of -Coolant Accident Evaluation Model for Once-Through Steam Generator Plants." Technical Specification 6.9.2 lists the references for

approved methods to determine the core operating limits and does not need to be revised to reflect the use of a new LOCA Evaluation Model. The LOCA linear heat rate limits used in the reload design are based on the results of the large break LOCA analyses. None of the SBLOCA cases are limiting with respect to establishing the maximum allowable linear heat rate limits. Therefore, the Technical Specifications and COLR do not need to be revised to reflect the results of the new SBLOCA analyses.

Question 5: You explain that the "HPI injection nozzle is not included in the break spectrum" in your submittal. Please provide greater detail and a drawing of what is and is not included in the break spectrum and then describe what break sizes and types are analyzed.

Response:

The SBLOCA break spectrum for B&W lowered-loop plants like Oconee has been established historically as the LOCA Evaluation Models and analyses have evolved. The current limiting SBLOCAs have been identified and confirmed by analyses as the cold leg pump discharge break (bottom of the pipe), the core flood line break, and the HPI line break. The limiting cold leg pump discharge break size is determined for each plant and set of assumptions by analyzing a sufficiently fine break spectrum. The limiting break size is identified by the highest PCT. Since the SBLOCA PCT has always remained well below the LBLOCA PCT, there has always been margin in the SBLOCA results for Oconee. The core flood line break and the HPI line break have been identified as special SBLOCA cases, at specific locations and with specific break sizes. The core flood line break (0.44 ft^2) corresponds to the inside diameter of the core flood nozzle insert that was installed to limit the break size. The limiting single failure and available ECCS equipment for the core flood line break are unique due to its specific location.

Similarly, the HPI line break (0.025 ft^2) corresponds to the inside diameter of the injection line where it connects to the nozzle on the cold leg. This break has unique ECCS performance due to the spilling of the HPI injection flow on the broken injection line, which results in a more adverse loss of ECCS flow. The submittal identified the established licensing position that a failure of the nozzle is not considered in the SBLOCA spectrum. Thus, break sizes greater than 0.025 ft^2 associated with the nozzle breaking

off the RCS and the affected HPI line being exposed to containment back pressure are not postulated. This position is shared by all B&W design plants. The submittal is not introducing any new licensing positions relative to the SBLOCA break spectrum. Drawings of the HPI nozzles are attached.

Question 6: Figures 15.28, 15.29, and 15.30 of the Final Safety Analysis Report (FSAR) show injected flow for two pump operation. Please include the total pump flow in this table so that the flow split can be better evaluated. The calculated peak centerline temperature (PCT) is higher for one pump operation. As a result, please include tables representing the calculated flow split for one pump operation. Describe the method of calculating the flow split for the different cases.

Response:

As part of the implementation of the proposed technical specifications, the referenced UFSAR figures will be revised to include the flow rates most recently assumed in the small break LOCA analyses performed with the approved RELAP5 Evaluation Model. The HPI boundary conditions for the small break LOCA analyses are as follows:

75% FP Cases
(Analysis Credits 1 HPI Pump Injecting Through One Train)

Core Flood Line Break

RCS PRESSURE (psig)	FLOW SPLIT (gpm)		TOTAL HPI FLOW (gpm) (2 loop sum)
0	221	168	389
600	221	168	389
1200	175	134	309
1500	153	117	270
1600	145	110	255
1800	128	97	225
2400	57	43	100

RCP Discharge Break

RCS PRESSURE (psig)	HPI INTACT LEG FLOW (gpm)	HPI BROKEN LEG FLOW (gpm)	TOTAL HPI FLOW (gpm) (2 loop sum)
0	167	223	390
600	167	223	390
1200	133	177	310
1500	116	155	271
1600	110	147	257
1800	96	129	225
2400	43	57	100

HPI Line Break

RCS PRESSURE (psig)	HPI INJECTED FLOW (gpm)	HPI SPILLED FLOW (gpm)	TOTAL HPI FLOW (gpm) (2 loop sum)
0	165	236	401
600	101	303	404
1200	21	378	399
1500	0	389	389
1600	0	389	389
1800	0	389	389
2400	0	389	389

Full Power Cases
(1 HPI Pump Injecting During First 10 Minutes, 2 Pumps Thereafter)

Core Flood Line Break (1^{st} 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	TOTAL HPI FLOW (gpm) (2 loop sum)
0	0	0	243	185	428
600	0	0	243	185	428
1200	0	0	189	144	333
1500	0	0	167	127	294
1600	0	0	159	121	280
1800	0	0	142	108	250
2400	0	0	72	55	127

Core Flood Line Break (After 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	TOTAL HPI FLOW (gpm) (4 loop sum)
0	193	196	243	185	817
600	193	196	243	185	817
1200	159	161	189	144	653
1500	139	140	167	127	573
1600	131	133	159	121	544
1800	115	117	142	108	482
2400	51	52	72	55	230

RCP Discharge Break (1st 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	HPI BROKEN LEG FLOW (gpm) (B1 Loop)	HPI INTACT LEG FLOW (gpm) (B2 Loop)	TOTAL HPI FLOW (gpm) (2 loop sum)
0	0	0	243	185	243	185	428
600	0	0	243	185	243	185	428
1200	0	0	189	144	189	144	333
1500	0	0	167	127	167	127	294
1600	0	0	159	121	159	121	280
1800	0	0	142	108	142	108	250
2400	0	0	72	55	72	55	127

RCP Discharge Break (After 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	HPI BROKEN LEG FLOW (gpm) (B1 Loop)	HPI INTACT LEG FLOW (gpm) (A1 +A2 + B2)	TOTAL HPI FLOW (gpm) (4 loop sum)
0	193	196	243	185	243	574	817
600	193	196	243	185	243	574	817
1200	159	161	189	144	189	464	653
1500	139	140	167	127	167	406	573
1600	131	133	159	121	159	385	544
1800	115	117	142	108	142	340	482
2400	51	52	72	55	72	158	230

HPI Line Break (1st 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	HPI SPILLED FLOW (gpm) (B2 Loop)	HPI INJECTED FLOW (gpm) (B1 Loop)	TOTAL HPI FLOW (gpm) (2 loop sum)
0	0	0	181	259	259	181	440
600	0	0	124	320	320	124	444
1200	0	0	48	384	384	48	432
1500	0	0	0	408	408	0	408
1600	0	0	0	408	408	0	408
1800	0	0	0	408	408	0	408
2400	0	0	0	408	408	0	408

HPI Line Break (After 10 minutes)

RCS PRESSURE (psig)	A1 Loop Flow (gpm)	A2 Loop Flow (gpm)	B1 Loop Flow (gpm)	B2 Loop Flow (gpm)	HPI SPILLED FLOW (gpm) (B2 Loop)	HPI INJECTED FLOW (gpm) (A1 +A2 + B1)	TOTAL HPI FLOW (gpm) (4 loop sum)
0	193	196	181	259	259	570	829
600	193	196	124	320	320	513	833
1200	159	161	46	383	383	366	749
1500	139	140	0	407	407	279	686
1600	131	133	0	407	407	264	671
1800	115	117	0	407	407	232	639
2400	51	52	0	407	407	103	510

Brief Discussion of Flow Split

HPI System flow rate boundary conditions are predicted by a computer code that models the hydraulic characteristics of the system. The flow model inputs such as piping resistances and pump characteristics are sufficiently conservative to ensure that flow results bound actual test data. Boundary conditions for the model are established to obtain conservative predictions of delivered flow to the RCS

for each SBLOCA case. For the RCP discharge breaks, each HPI line is assumed to be at RCS pressure. For the HPI line break case, the broken HPI line is assumed to be at containment pressure and the remaining lines are exposed to RCS pressure.

For each specific accident analysis (i.e., core flood line break, RCP discharge break, and HPI line break), one piping injection loop is intentionally modeled to have an additional degree of flow resistance than that found in the normal hydraulic flow model. This is accomplished by increasing the hydraulic minor loss coefficient in the chosen loop. Accordingly, an artificial flow imbalance is created in the system model. Depending upon the specific accident being evaluated, the flow imbalance is conservatively adjusted to minimize injected flow to the core.

Question 7: The FSAR Figures 4-46 and 4-49 showing the small break (SB) LOCA model interfaces and nodalization, are being removed. Rather than remove the figures, please update them with the new methodology interfaces and nodalization.

Response:

FSAR Figure 15-45, "LOCA - Small Break Analysis Code Interfaces", will be deleted and not replaced with a new figure because there are no code interfaces with the new RELAP5-based Evaluation Model. The entire SBLOCA analysis is performed within RELAP5.

FSAR Figure 15-49, "LOCA - CRAFT2 Small Break System Nodalization", will be deleted and not replaced with the similar RELAP5 nodalization diagram because Framatome Technologies considers this nodalization diagram to be proprietary information.

Question 8: In "Insert 4" to the FSAR, you describe two errors in the analysis methods and inputs that resulted in the calculated PCT to go up by 92°F. Please describe the reanalysis performed as a result of the significant error in the original analysis. Was it performed by rerunning the computer code with the changes or were the changes evaluated to determine a Δ PCT? Additionally, please verify that all of the other cases that were analyzed were also performed using a model with the correct inputs.

Response:

Subsequent to the September 4, 1997 submittal, the SBLOCA break spectrum has been reanalyzed to include several desired input and modeling updates. There are no known errors or issues outstanding in these revised reanalyses. The reanalyses are described in the response to Question 3. The results presented in the response to Question 3 supersede the results given in Attachment 3 to the March 31, 1997 Duke submittal which proposes the Technical Specification changes for the HPI System. These results also supersede the information provided in the Duke September 3, 1997, submittal which is being withdrawn. The UFSAR will be updated following approval of the March 31, 1997, proposed license amendment.

Question 9: The proposed change to the licensing basis for Oconee would increase the equipment needed and the operator actions necessary to mitigate a spectrum of SBLOCAs. To successfully mitigate the consequences of the spectrum of SBLOCAs, the equipment now needed includes the auxiliary feedwater systems and successfully depressurizing the steam generators. The operators are required to perform these actions manually along with a number of others. With more equipment needed and more operator actions necessary, there is a greater chance of equipment failure and operator failure. As a result, please quantify the increased risk as a result of relying on additional equipment and putting a greater burden on the operators.

Response:

The EFW System has been credited in past SBLOCA analyses as described in responses to NUREG-0565. However, actions to raise steam generator levels to the loss of subcooled margin setpoint were only assumed in the smaller small break LOCAs. The requirement to depressurize the steam generators using the ADVs is a new requirement that is most relevant to the reduced power SBLOCA cases. The additional systems and actions that are being used to mitigate the SBLOCAs are only required in order to meet the single failure criterion. These actions are not needed to mitigate these LOCAs when both HPI pumps are available, the most probable situation.

However, even if one assumes that the EFW System and steam generator depressurization are required for the LOCAs of interest, the risk increase is very small. The LOCAs that are of concern for this Technical Specification change are those that occur in specific locations. These locations are

in the reactor coolant pump discharge and in the HPI lines (between the HPI injection nozzle and the check valve, a distance of approximately three feet). The frequency of LOCAs that would be expected to occur at these specific locations is a small fraction of the total frequency from all LOCAs in all possible locations. The total frequency of LOCAs of all sizes and from all locations from the latest revision to the Oconee PRA is 2.1E-03/yr. These frequencies are calculated based on the historical occurrence of, or non-occurrence of, LOCAs of various sizes. For purposes of this discussion the frequency of the specific pipe breaks of concern is assumed to be 10% of the total LOCA frequency. An estimate of this frequency using the EPRI pipe rupture methodology (EPRI TR-102266, Pipe Failure Study Update) resulted in a frequency of approximately 5E-06, for breaks from 0.5″ to 6.0″,which is significantly lower than is assumed in the following example.

The sequence of concern is a LOCA with a failure of an HPI pump, and failure of EFW or failure of the operators to depressurize the RCS using the steam generators.

LOCA	HPI Failure	EFW Failure or Operator Error	Cut Set Frequency
2.1E-04	1E-02	1E-03	2E-09
2.1E-04	1E-02	0.1	2E-07

In this example, the failure of a single HPI pump is estimated at 1E-02 and a failure of two or more sources of EFW is estimated at 1E-03. The redundancy in the EFW system makes the hardware failure contribution to core damage frequency from this sequence insignificant. The assumed operator error probability of 0.1 is conservative for a proceduralized action. Other contributors to the core damage frequency for this scenario such as power failures are expected to be much smaller than the examples given above. One of these contributors is hardware failures in the equipment needed for depressurization. Both the atmospheric dump valves and the turbine bypass valves are available to perform the depressurization. This redundancy makes the hardware failure contribution to the depressurization negligible.

The total core damage frequency for Oconee is calculated to be 8.9E-05/yr with a LOCA contribution of 6.8E-06/yr. It is seen that the conservatively calculated values in the table above are a small fraction of the overall and LOCA core damage frequency. Any increase in risk associated with the

need for EFW or the atmospheric dump valves to mitigate some LOCAs is expected to be insignificant.

Question 10: While reviewing your original submittal (March 31, 1997), we discovered an apparent inconsistency in the licensing basis that does not appear to affect the unreviewed safety question. That submittal is requesting a change to the licensing basis to redefine the function of the HPI system and state that it is not required for long-term cooling. The current licensing basis for the system, as stated in the current TS Bases on page 3.3-6, is that the HPI system is required for long-term cooling. Page 10 of the March 31 submittal states that, "systems required for long term core cooling are required to withstand passive failures." As a result according to the current licensing basis, the HPI system should be able to withstand passive failures. We have not performed an in-depth review of the system (we are planning to in January following the system reliability study); however, a quick look at the system indicates that with the suction of the three pumps cross connected, the system does not appear to be passive failure proof. Additionally, from the discussion in the submittal, it appears that Duke Energy may not consider the need for the system to be passive failure proof. Please address this apparent noncompliance with the current licensing basis.

Response:

The licensee agrees with the staff that the statement currently in the bases of Technical Specification 3.3 could be interpreted to mean that HPI is required for long-term cooling. However, a review of the licensing basis for Oconee concludes that long term cooling is defined as decay heat removal via the LPI System. In Supplement 1 to the Oconee Units 2 and 3 SER, the staff states "long-term cooling is established in the applicant's opinion when the core is covered with mixture, more water is being supplied than leaked, the pressure is stabilized and the cladding temperature is falling." This definition applied to large break LOCAs. The Oconee ECCS was designed to withstand passive failures during long-term core cooling, which is based on the assumption that the RCS is depressurized and decay heat is being removed by the LPI System.

The original licensing of Oconee did not consider HPI as required for long-term core cooling. Additional evidence to support this fact is that the core flood line break analyses credit one HPI train and one core flood line during the

initial stages of the accident. However, as described in Supplement 14 to the FSAR dated January 29, 1973, long-term ECCS operation is based on alignment of the remaining LPI train to provide injection. Thus, although HPI injection was adequate to assure core cooling, long-term core cooling was based on the prerequisite of establishing LPI flow to the core.

In addition, modifications to provide a crossover flow path in the HPI System in 1978 resulted in a Technical Specification requirement to operate with the HPI suction header valves (HP-98, HP-99, and HP-100) open. This change was approved by the staff and was necessary to assure the acceptance criteria of 10 CFR 50.46 would be satisfied for the spectrum of small break LOCAs. Implicit in this licensing amendment is the fact that the HPI System is required to withstand active single failures, but not passive single failures.

On February 17, 1989, Duke proposed a license amendment to address the LPI to HPI flowpath necessary for HPI piggyback operation. This license amendment was in response to a design discovery by Duke that the HPI piggyback flow path had not been appropriately addressed in the design basis (LER 269/88-06). In the Technical Specification change submitted on February 17, 1989, Duke proposed the following addition to the Bases to Technical Specification 3.3 "The requirement for a flowpath from LPI discharge to HPI pump suction is provided to assure availability of long-term core cooling following a small break LOCA in which the BWST is depleted and RCS pressure remains above the shutoff head of the LPI pumps." This statement exists in the current Bases.

Based on the original licensing basis of the plant, the intended meaning of the phrase "assure availability of long term core cooling" is to assure the transition from HPI injection to long-term core cooling via the LPI System. The EOP has guidance to terminate HPI flow when sufficient LPI flow has been established. Passive failures are not postulated in the HPI System since it is not credited for long-term core cooling. Duke agrees with the staff that the current Bases to Technical Specification 3.3 warrants clarification. As such, the Bases proposed by Duke in its March 31, 1997, submittal revised the description of the piggyback mode of operation for the HPI System.

Question 11: Describe the steps and times associated with briefing the operator(s) and ultimately taking manual operator action(s) to realign HPI within 10 minutes.

Response:

Operations Management Procedure 2-1, Enclosure 4.9 lists procedural items which all licensed operators shall have committed to memory. One of the items in this list includes verification of sufficient HPI flow in both headers within 10 minutes of a loss of core subcooling margin. Operators are expected to perform this action without procedural guidance, from memory. Additionally, in the unlikely event that the memorized actions were missed, procedural guidance is provided as follows. Immediately upon Engineered Safeguards (ES) actuation, the Emergency Operating Procedure (EOP) reader gives Section 505, ES Actuation, to a Control Room Operator (CRO) and directs him to perform it. No briefing is required since all directions are contained within the checklist and the operators are very familiar with this procedure from frequent usage in requalification training. All of the following actions are performed from within the control room area. The following steps reflect guidance in the current version of the EOP. Oconee is in the process of upgrading the EOP and these steps will change slightly. The CRO steps are as follows:

STEP	ACTIONS
Verify appropriate ES channels actuated	Review eight rows, at most, of blue indicating lights and eight rows of white indicating lights on the ES panels. (Failures requiring HPI cross-connection would likely be noticed at this time and action from memory to re-align HPI.)
Check Subcooling Margins (SCM)	Monitor seven indications of SCM, three for the core and two each for the loops.
If any SCM indicates 0°F, trip all RCPs.	Secure all RCPs if required.
Verify HPI header flow	
• Obtain RCS pressure	Monitor gauges on control board
• Obtain HPI header flow down each header	Monitor gauges on control board
• Determine required HPI header flow	Refer to curve in ES actuation procedure
• Determine if HPI flow is adequate	Compare actual HPI flow with required HPI flow
If HPI header flow is inadequate, open associated cross-connect valve	Hold control switch in the open position until cross-over valve is open

In addition, the operator action to cross-connect HPI trains has been previously reviewed and approved by the staff. In a letter dated April 14, 1978, Duke notified the staff of an error in B&W's small break LOCA analyses. This letter indicated that a break on the discharge side of the reactor coolant pumps had been determined to be more limiting than the previously considered worst case break location on the suction piping of the reactor coolant pumps. In response to this issue, Duke implemented modifications to the HPI System to install cross-connect lines with valves (HP-409 and HP-410) that could be operated from the control room to cross-connect flow and assure adequate injection. Duke's modification was described in a July 14, 1978, submittal to the staff. The staff approved the modification in a Safety Evaluation dated December 13, 1978. In its Safety Evaluation, the staff stated "we conclude that the proposed long-term modification, with the assumed operator actions, is consistent with these analyses and is acceptable as a permanent solution to the small break LOCA problem."

Question 12: Provide the demonstrated times for operators that would be expected to complete the manual action(s) to realign HPI.

Response:

The operators' ability to perform the task of aligning HPI flow through the crossover valves is periodically evaluated on Annual Requal Exams using Job Performance Measure (JPM) CRO-65. (Job Performance Measures are evaluation tools used to verify tasks can be performed successfully and, where applicable, within the required time frames.) Exam results indicate that the approximate total time to perform these actions is < 4 minutes. This time is well within the required 10 minute time frame.

Question 13: Discuss operator training that is necessary to carry out the manual operator actions, including any operator qualifications required to carry out these actions.

Response:

HPI crossover alignment - Classroom training on the bases for this alignment and the importance for assuring adequate HPI flow is begun at the non-licensed operator (NLO) level. This is continued in License Prep class with the addition of training on the procedures where this alignment might be

performed. Additionally, simulator training is provided in License Prep class where operators are required to perform the actual steps to complete this evolution. Successful completion of the License Prep class ensures that all operators that would be expected to perform this task are adequately trained to do so. To maintain proficiency, this task is covered periodically in Licensed Requal training and there is a Job Performance Measure on this task that is used on annual requal exams to evaluate the ability of a cross section of operators to perform this task successfully. Some of the Active Simulator Exams used on the annual requal exam also require this task to be completed. Only licensed operators would perform this evolution in the control room, and completing the requirements for licensed requal ensures sufficient ability to do so correctly.

Feeding the Steam Generators (SGs) to the Loss of SCM setpoint with Emergency Feedwater (EFW) - This task is covered in the License Prep class including the bases for the task as well as how to perform it. Simulator training is also provided to teach the correct method to perform this evolution. Successful completion of the License Prep class ensures that all operators that would be expected to perform this task are adequately trained to do so. To maintain proficiency, this task is periodically covered in Licensed Requal training. Some of the Active Simulator Exams used on the annual requal exam also require this task to be completed. Only licensed operators would perform this evolution in the control room and completing the requirements for licensed requal ensures sufficient ability to do so correctly.

Steaming SGs with the Atmospheric Dump Valves (ADVs) - Training is provided on operation of the ADVs in the classroom as well as On-The-Job training. NLOs must qualify to this task prior to assuming the watch on the associated duty station. Requalification to this task is required at least once every two years. There is a JPM on this task that is used to evaluate NLOs (some but not necessarily all NLOs) at least bi-annually.

Question 14: Provide the results of a sensitivity study that would evaluate the significance of demonstrated response times that exceed the assumed response time of 10 minutes to realign HPI.

Response:

The credit for manual operator action to realign the HPI System at 10 minutes was reviewed and approved by the NRC in a Safety Evaluation dated December 13, 1978. The SBLOCA reanalyses performed to support the proposed technical specification revision do not revise in any way this operator action. No sensitivity studies are available to respond quantitatively to this question. The realignment of the HPI System is only applicable to the full power SBLOCA analyses. The new full power limiting PCT is less than 1400°F, which maintains a large margin to the 2200°F acceptance criterion in 10 CFR 50.46. This indicates that additional time beyond 10 minutes is available for this operator action before the results become unacceptable.

Question 15: Provide a description of the information needed by the control room staff to determine if there is a need to realign HPI.

Response:

In order to determine that realignment of HPI will be required, the operator uses RCS pressure and HPI header flows 'A' & 'B', and compares them with a graph in the Emergency Operating Procedure. RCS pressure and each HPI header flow can all be read on the front control board in the control room. All instrumentation is qualified, QA-1 instrumentation.

Question 16: Provide a copy of the sections of the procedures that are relevant to the manual operator action(s).

Response:

Oconee is currently in the process of an EOP Upgrade. The licensee discussed this upgrade with the NRR project manager and it was agreed that the requested EOP sections would be provided when the upgrade is completed.

Question 17: Describe how operator(s) become aware that there is a need for manual action?

Response:

HPI crossover alignment - OMP 2-1 memorization items have the operator verify adequate HPI flow in both headers within 10 minutes. As a backup, proceduralized mechanism, to ensure actions are completed, the EOP also provides guidance as follows. Following actuation of ES, steps 2.3 & 2.4 of EOP Section 505, ES Actuation, have the operator compare actual HPI header flows versus required HPI header flow. If either HPI header flow is not adequate, the associated HPI cross-over valve is opened. All required information is available on the front control board and all actions to realign HPI are performed with switches on the front control board.

Feeding the Steam Generators (SGs) to the Loss of SCM setpoint with EFW - When a Loss of Subcooling Margin occurs while performing the actions in the EOP, an immediate transfer is made to Section 501, Loss of Subcooling. If either Low Pressure Injection (LPI) header flow indicates less than 1000 gpm flow, step 5.0 directs initiating EFW flow to raise SG levels to the Loss of Subcooling Margin setpoint. Subcooling Margins and LPI header flows are monitored on the front control board using qualified, QA-1 instruments. All actions to begin feeding EFW to the SGs are performed on the front control board in the control room.

Also note that during the time before the operator can begin to feed up to the Loss of Subcooling Margin setpoint, the Main FDW system will begin increasing SG levels as follows. When SCM is lost, all reactor coolant pumps (RCPs) are immediately secured. When all RCPs are secured the Main FDW system will begin to increase SG levels until the operator has a chance to begin using the EFDW system to raise the levels.

Steaming SGs with the Atmospheric Dump Valves (ADVs) - Following a Loss of SCM on SB LOCAs, the EOP reader will end up in CP-602, SG Cooldown with Saturated RCS. Step 4.1 of this section directs maintaining SG(s) pressure < RCS pressure. Normally the Turbine Bypass Valves would be used to perform this action from the front control board. If SG pressure doesn't decrease as Turbine Bypass Valve (TBV) demand is increased, the EOP directs use of the ADVs and an operator would be dispatched to perform this action.

The previously mentioned EOP upgrade will require the operator to check TBV operability as part of the second step in the Subsequent Actions Section of the EOP. If the TBVs

are inoperable, an NLO will be dispatched immediately to prepare for steaming the generators with the ADVs. This action will leave only one valve to be operated if steaming is desired, and stages the NLO at the location just outside the control room where the ADVs are located.

Question 18: Discuss how many operators will perform the manual action?

Response:

HPI crossover alignment - One control room operator

Feeding the Steam Generators (SGs) to the Loss of SCM setpoint with EFW - One control room operator (Since this is not performed at the same time as HPI realignment, this is frequently the same operator that performed that alignment.)

Steaming SGs with the Atmospheric Dump Valves (ADVs) - One Non-Licensed Operator can perform this function but depending upon availability more NLOs may assist. Any times addressed in this document assume one operator.

Question 19: ANSI-58.8 supplies estimates of reasonable response times for operators, but does allow licensees to use time intervals derived from independent sources, provided they are based on task analyses with consideration given to human performance. Discuss whether ANSI-58.8 has been considered in determining the times for manual operator action.

Response:

ANSI 58.8 was not used when the operator action times were developed for the small break LOCA analyses. Duke has reviewed this standard with respect to the assumed operator action times credited in the small break LOCA analyses. ANSI 58.8 describes a methodology for determining minimum time frames that can be credited for manual operator actions to mitigate design basis events. By this standard no actions performed outside the control room can be credited to occur in less than 30 minutes following initiation of the event. The standard allows for exceptions from this time limit if appropriate justification is provided.

Operator actions within the control room have been verified through simulator exercises. These manual actions within the control room are to cross-connect HPI trains within 10

minutes and begin raising steam generator level in one steam generator within 20 minutes of the ES signal. The only operator action required outside the control room in less than 30 minutes is the operation of the atmospheric dump valves on one steam generator. As described previously, this action is a Job Performance Measure (JPM) for the NLOs and can be accomplished within the 25 minutes assumed in the accident analyses that initiate from 75% FP. An expert panel, consisting of representatives from Operations, Operations Training, Engineering, and Licensing reviewed the EOP and the operator action necessary to depressurize one steam generator. The panel concluded that past JPMs and simulator cases for the relevant small break LOCAs support the adequacy of the assumed 25 minutes. The atmospheric dump valves are located just outside the control rooms on the Turbine Deck and can be opened by an NLO within a few minutes of a request by a control room operator.

Question 20: Discuss the following relative to the proposed manual operator action(s):

a) Potentially harsh or inhospitable environmental conditions.

b) Ingress/egress paths taken by the operator(s) to perform functions, and

c) Additional support personnel and equipment required by the operator to carry out actions.

Response:

a) Potentially harsh or inhospitable environmental conditions

The manual operator actions required by this scenario take place in either the control room (operation of HP-409/410 & feed to loss of subcooled margin setpoint) or the turbine building (operate ADVs). Neither of these areas would be expected to have a harsh or inhospitable environment during a SBLOCA.

b) Ingress/egress paths taken by the operator(s) to perform function

The two actions taken in the control room do not require ingress/egress. Manual operation to operate ADVs involves exiting the control room area and walking out on to the

fifth floor of the Turbine Building to the ADVs. The control room is located on the same elevation as the fifth floor of the Turbine Building.

c) Additional support personnel and equipment required by the operator to carry out actions

No support personnel or equipment are required to perform any of the manual actions.

Question 21: Describe the information required by the control room staff to determine that such operator action is required, including qualified instrumentation used to diagnose the situation and to verify that the required action has been successfully taken.

Response:

HPI crossover alignment - As previously described in # 11 and # 17, the determination is made based on RCS pressure and HPI header flows. Success is verified by flow as indicated on the HPI crossover flow instruments. Reg Guide 1.97 qualified, QA-1 instumentation is provided in the control room for each of these parameters all located on the front control board.

Feeding the Steam Generators (SGs) to the Loss of SCM setpoint with EFW - Determination is made based on indication of Loss of Subcooling Margin and either LPI header flow less than 1000 gpm. Success is verified by monitoring increasing SG levels using Extended Startup Range Level instrumentation. Reg Guide 1.97 qualified, QA-1 instumentation is provided in the control room for each of these parameters all located on the front control board.

Steaming SGs with the Atmospheric Dump Valves (ADVs) - Need is determined by the failure of SG pressure to decrease upon an increase in TBV demand. Success is verified by observing SG Outlet Pressure decreasing below RCS pressure as ADVs are operated. Reg Guide 1.97 qualified, QA-1 instumentation is provided in the control room for each of these parameters all located on the front control board.

Instrument	Range	Qualification
ICCM RCS Pressure Train A	0-3000 psig	Qualified, QA-1
ICCM RCS Pressure Train B	0-3000 psig	Qualified, QA-1
HPI Flow Train A	0-750 gpm	Qualified, QA-1
HPI Flow Train B	0-750 gpm	Qualified, QA-1
HPI Crossover Flow Train A	0-750 gpm	Qualified, QA-1
HPI Crossover Flow Train B	0-750 gpm	Qualified, QA-1
ICCM Train A Core Subcooling Margin	N/A	Qualified, QA-1
ICCM Train B Core Subcooling Margin	N/A	Qualified, QA-1
OAC Core Subcooling Margin	N/A	Not Qualified
ICCM Train A Loop Subcooling Margin	N/A	Qualified, QA-1
ICCM Train B Loop Subcooling Margin	N/A	Qualified, QA-1
OAC Loop A Subcooling Margin	N/A	Not Qualified
OAC Loop B Subcooling Margin	N/A	Not Qualified
LPI Header Flow Train A	0-6000 gpm	Qualified,QA-1
LPI Header Flow Train B	0-6000 gpm	Qualified, QA-1
SG Extended S/U Range Lvl Train A Primary	0-388 inches	Qualified, QA-1
SG Extended S/U Range Lvl Train A Backup	0-388 inches	Qualified, QA-1
SG Extended S/U Range Lvl Train B Primary	0-388 inches	Qualified, QA-1
SG Extended S/U Range Lvl Train B Backup	0-388 inches	Qualified, QA-1
Total EFW Flow Trn A Primary	0-1200 gpm	Qualified, QA-1
Total EFW Flow Trn A Backup	0-1200 gpm	Qualified, QA-1
Total EFW Flow Trn B Primary	0-1200 gpm	Qualified, QA-1
Total EFW Flow Trn B Backup	0-1200 gpm	Qualified, QA-1
SG Outlet Pressure A1	0-1200 psig	Qualified, QA-1
SG Outlet Pressure A2	0-1200 psig	Qualified, QA-1
SG Outlet Pressure B1	0-1200 psig	Qualified, QA-1
SG Outlet Pressure B2	0-1200 psig	Qualified, QA-1

Question 22: Discuss the ability to recover from plausible errors in performance of manual actions and the expected time required to make such a recovery.

Response:

The results presented for the SBLOCA reanalyses include numerous Evaluation Model conservatisms, which have been reviewed and approved by the NRC, in addition to many

conservative initial and boundary conditions. The integrated application of these conservative modeling approaches and assumptions ensures a conservative result. In addition, margin is maintained between the PCT results and the 2200°F acceptance limit. The operator actions required to mitigate SBLOCAs consists of the following:

1) Trip all reactor coolant pumps following a loss of subcooled margin. This action is to be taken immediately (less than two minutes)

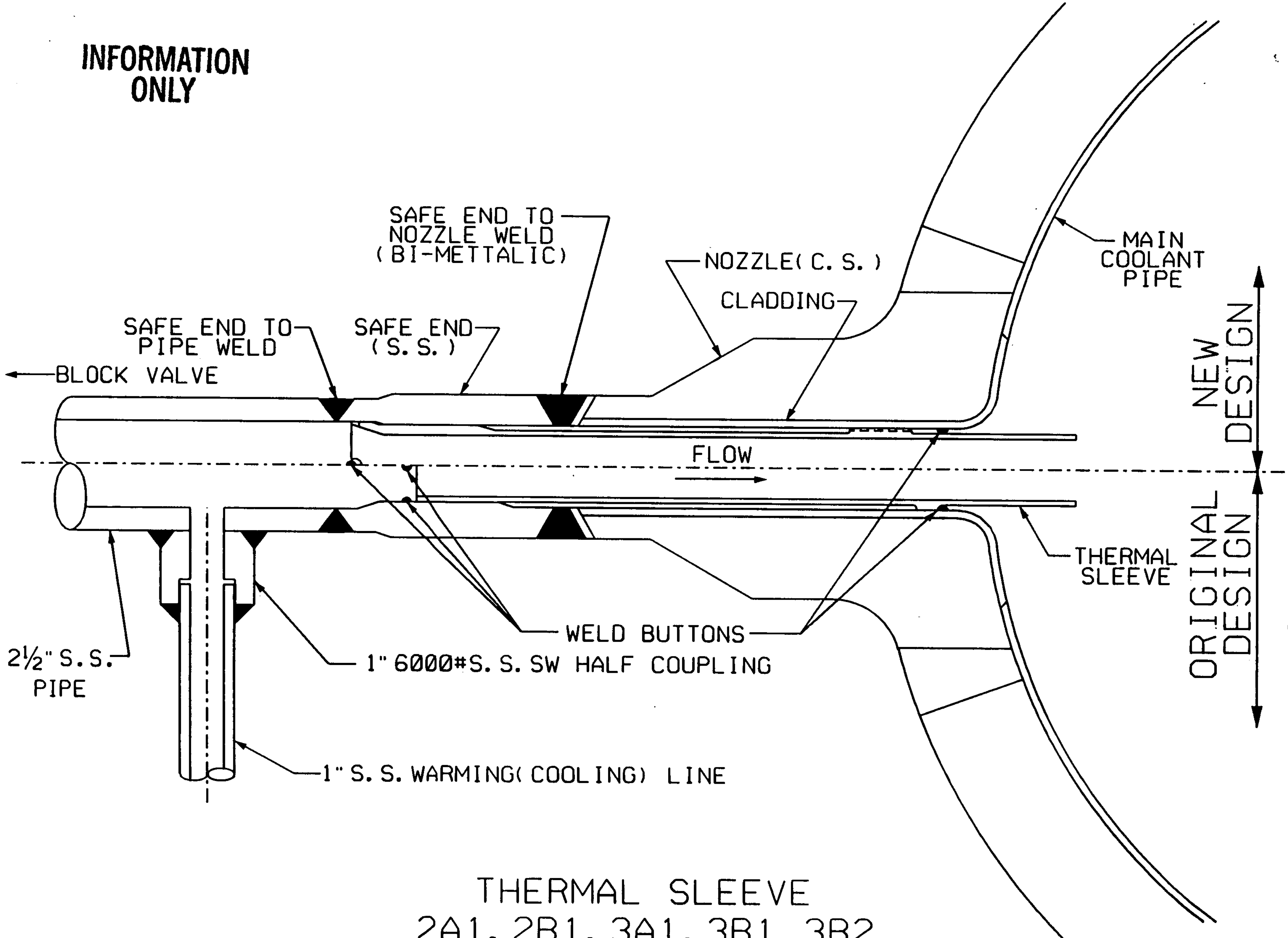
2) If flow is not confirmed in both HPI trains, then open cross-connect valves within 10 minutes (not applicable if only one HPI pump operating).

3) Raise steam generator levels to the loss of subcooled margin setpoint at 20 minutes on one steam generator.

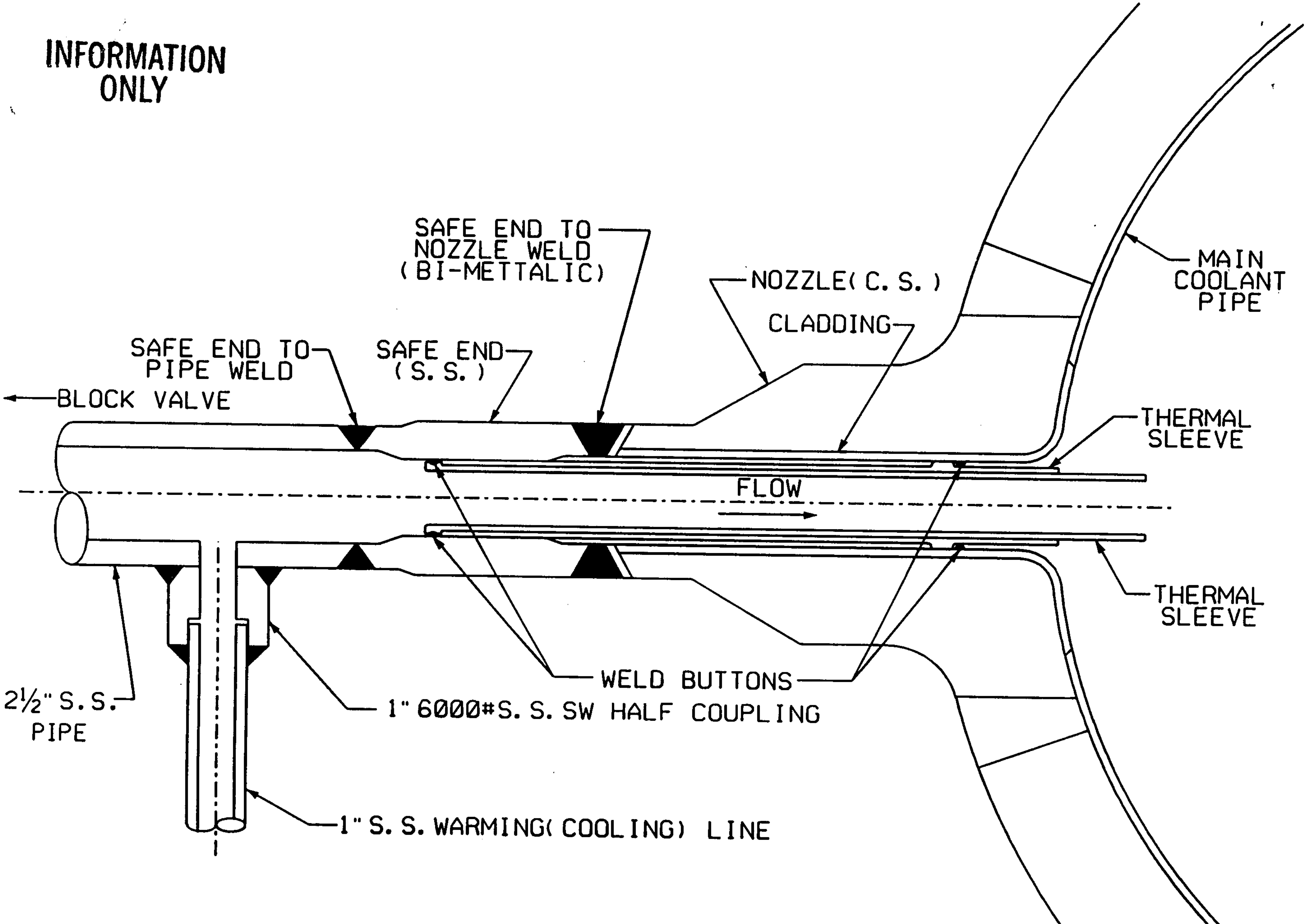
4) Steam one steam generator within 55 minutes for full power initial conditions or one SG within 25 minutes for the one HPI pump 75% power initial condition.

The first two operator actions have been in place for many years and are not new to the licensing basis. The third and fourth items have been in the emergency operating procedures for many years, although the times associated with these actions are new to the SBLOCA reanalyses and the licensing basis. As stated in the response to Question #1 above, the steam generator feeding and steaming actions are assumed in both steam generators for the full power cases, but have been shown by sensitivity study to only be required in one steam generator. Therefore, the licensing basis requirement is to steam one generator to meet the acceptance criteria of 10 CFR 50.46. The Oconee design has good redundancy in both feedwater sources and steaming capabilities for SBLOCA mitigation. Based on these design features, emergency operating procedures and training, and the analysis results, successful mitigation of SBLOCAs has been demonstrated. Successful and timely operator action is a key element in this mitigation strategy and in the analyses. The margin between the PCT results and the acceptance limit, and the significant overall conservatisms in the Evaluation Model and the analyses provide some margin to offset some delays in operator actions. However, the operator actions are a required element of the mitigation strategy and licensing basis.

INFORMATION ONLY



THERMAL SLEEVE
2A1, 2B1, 3A1, 3B1, 3B2



UNIT 1 THERMAL SLEEVE