NUREG-0560

STAFF REPORT ON THE GENERIC ASSESSMENT OF FEEDWATER TRANSIENTS IN PRESSURIZED WATER REACTORS DESIGNED BY THE BABCOCK & WILCOX COMPANY

Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission

Available from
National Technical Information Service
Springfield, Virginia 22161
Price: Printed Copy $13.25; Microfiche $3.00

The price of this document for requesters outside of the North American Continent can be obtained from the National Technical Information Service.

NUREG-0560

STAFF REPORT ON THE GENERIC ASSESSMENT OF FEEDWATER TRANSIENTS IN PRESSURIZED WATER REACTORS DESIGNED BY THE BABCOCK & WILCOX COMPANY

Manuscript Completed: May 1979
Date Published: May 1979

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

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

List of Tables

List of Figures

TABLE OF CONTENTS (Continued)

EXECUTIVE SUMMARY

On March 28, 1979, the Three Mile Island Unit 2 (TMI-2) nuclear power plant experienced a feedwater transient that, through an unusual sequence of failures, led to a small break loss-of-coolant accident and resulted in significant core damage. The failures that were experienced occurred in the general areas of design, equipment malfunction, and human error. In response to this event, a task group was formed to provide an early assessment of the generic aspects of the feedwater transient and the related ensuing events at TMI-2 to determine bases for continued safe operation of other reactor plants similar to TMI-2 that were designed by the Babcock & Wilcox Company (B&W). Consideration was given by the task group to initiating events other than loss of feedwater where it was determined that such events could lead to a similar transient. In addition, consideration was given to possible impact on other PWR plants designed by Westinghouse and Combustion Engineering.

A recent review by the staff on the frequency of feedwater transients occurring in B&W plants indicates that 27 transients have occurred in nine plants during the past year. This corresponds to a frequency of three per year per plant. The corresponding rate for the other PWR plants is about two per year per plant.

The results of this assessment are presented in this report by the task group in the form of a set of findings and recommendations in each of the principal review areas. Additional review of the accident is continuing and further information is being obtained and evaluated. Any new information will be reviewed and modifications to the results of the initial review will be made as appropriate.

Many actions have been taken since the TMI-2 event by the staff and industry to minimize the likelihood of recurrence, including the shutdown of the four operating B&W facilities for short-term corrective actions which will also be taken on the other B&W plants before they restart. As this response is being published, there are other ongoing activities, including discussions with Westinghouse, Combustion Engineering, and various utilities, to further improve the safety margins in these plants. Thus, this is a status report and is not considered to be a complete and final set of recommended actions. It is not a general critique of licensee and NRC response to the accident. Such review will follow while other ideas are being formulated, but that is beyond the scope of this report. It is likely that other actions, including long-term actions, will be required as the overall review of the TMI-2 accident progresses.

Prior to the TMI-2 accident, the general approach used for accident analyses was to ensure conservatism in the analysis models and results. Consideration has been given to the development of best-estimate codes, but licensing calculations were done on a conservative basis. It is recognized that shortcomings resulted from this approach. For example, the analysis of the September 24, 1977 transient at Davis-Besse did not include the phenomenon of voiding in the core and long-term natural circulation cooling. Other areas that need to be reevaluated include the use of safety and non-safety grade equipment for the termination of transients and mitigation of accidents.

On the basis of the results of this interim review, the task group concludes that certain design improvements and other actions already being implemented on B&W plants in accordance with Commission orders are necessary before plant operation can be resumed. These actions are being specified in the shutdown orders that resulted from this generic review; e.g., reactor trip on upsets in the secondary cooling system of the plant, additional operator training, improvements in auxiliary feedwater reliability, and further analyses of small break loss-of-coolant accidents. Other recommendations for longer term improvements are specified in the report.

The staff believes implementation of the recommendations stated in this report would further increase the safety margins in the B&W pressurized water reactor (PWR) plants. Certain of these recommendations also apply to the other PWR vendors (Westinghouse and Combustion Engineering) as well as to boiling water reactor (BWR) plants designed by the General Electric Company (GE).

The principal recommendations resulting from the initial review are given in Section 8.0 and are summarized below. In general these recommendations include the short-term actions taken in connection with IE Bulletins and the recent shutdown of the B&W plants and extend certain actions to longer term improvements.

- Plant design features unique to the B&W plants (e.g., OTSG and ICS) should be evaluated with regard to interactions in coping with transients. The mitigating systems (e.g., HPI) should also be included in the study.

- Plant instrumentation should be provided to give improved information on reactor coolant level and margin to bulk coolant saturation.

- A study should be made to see whether there are design deficiencies that may be corrected to reduce the frequency of feedwater transients. The reliability of auxiliary feedwater systems should be improved.

- Improved means for detecting a stuck-open power-operated relief valve (PORV) should be provided. In addition, consideration should be given to upgrading the PORV classification to safety grade and the associated controls and instruments to new standards for control systems; or, as an alternate, consideration should be given to closing the relief valve and block valve during power operation if resetting of the set point is not effective in reducing actuation of the PORV.

- Provisions should be made to assure that essential containment isolation will occur automatically when the safety injection system is actuated or a high containment radiation level is reached.

- A study should be made by NRC, the licensees, and designers of the design basis for the residual heat removal (RHR) system with regard to its availability and operability as a low-pressure heat removal system when the reactor coolant system is contaminated.

- An improved system, including reporting and data assembly, should be developed by the NRC to more effectively evaluate actual data from operating experience to assess whether the trend of data from the occurrence of equipment malfunctions or other events indicates excessive challenges to the plant safety systems.

- Increased use of simulator training (and retraining) is needed, particularly in connection with emergency actions involving single failures, equipment malfunction, and operator actions, including extension to natural circulation cooling.

- A study should be undertaken by NRC of actions that could make the operator a more effective recovery agent or incident/accident mitigator. Such actions would extend the defense-in-depth concept through the use of on-line diagnostic computer systems to seek ways to prevent (inhibit) inappropriate actions and promote productive intervention.

- Operator training should be restructured to give more emphasis to protecting the reactor core under potentially degraded plant conditions.

- Emergency procedures should be written in real time as an aid for operators to study and memorize those aspects that deal with the initial short-term response. The procedures should be written in conjunction with results available from analyses to promote proper understanding and proper identification of critical decision points.

- Operators must have a better understanding of any limitations and must have a proper understanding of the plants. Each senior operator must direct activities and must not act simply as another operator.

- More emphasis is needed on human engineering in control room design to improve operator comprehension and response.

- All classes of operating plants should be reanalyzed using failure mode and effects analysis to identify realistic plant interactions resulting from failures in non-safety systems, safety systems and operator actions during transients and accidents. Associated analyses should be performed for a sufficient time duration to establish that a stable plant condition had been reached including natural circulation. Explicit consideration should be given to the effects of a loss of onsite or offsite power.

- For all classes of operating plants, additional analyses should be performed of reactor coolant system breaks in the range of very small breaks (e.g., representative of a stuck PORV or small line rupture) and carried out until a stable, long-term cooling condition is established.

- NRC should develop (and utilize for audit calculations) quick engineering types of analyses methods capable of both realistic and conservative application to operating transients and small break LOCAs from initiation through stable long-term cooling and of other events such as a small break in a main steam line or a steam generator tube rupture.

- Standard Review Plans should be updated to ensure that the TMI-2 accident is taken into account during the normal course of licensing review for all future plants (OL and CP).

- Regulatory guidance should be developed to give explicit interpretation of those General Design Criteria where variable interpretation in the past has led to inadequacies in instruments and associated requirements for control of anticipated transients and accident sequences.

- Technical Specifications should be reviewed to ensure that (a) plant alignment and system operability requirements are clearly stated, (b) unplanned events are required to be reported to NRC whether or not technical specifications are violated, and (c) restrictive provisions do not inhibit operator improvisation under abnormal conditions.

1.0 INTRODUCTION

On March 28, 1979, the Three Mile Island Unit 2 (TMI-2) nuclear power plant experienced a loss of normal feedwater supply that led to a turbine trip and later to a reactor trip. Subsequently, a series of events took place that resulted in significant damage to portions of the reactor core. It is believed that the sequence of events that led to core damage involved equipment malfunctions, design related problems and human errors that contributed to varying degrees to the consequences of the accident. Because plant conditions were substantially degraded, improvised operating modes for post-accident recovery were required.

On April 2, 1979, while post-accident recovery operations were taking place at TMI-2, a task group was appointed to perform a generic assessment of feedwater transients in Babcock and Wilcox (B&W) plants in light of operating experiences, including the TMI-2 accident, to determine bases for continued safe operation of these plants in both the short term and the long term. The Task Group was directed by Robert L. Tedesco of the Division of Systems Safety in the Office of Nuclear Reactor Regulation. The principal members of the task group were Paul Check, James Watt, Stephen Hanauer, Rodney Satterfield, Zoltan Rosztoczy, Richard Ireland, Gus Lainas, Paul Collins, and Newton Anderson.

The charter for the group is as follows:

> Given the operating experience with feedwater transients in operating B&W designed reactors, assess whether reactor and plant systems at these plants provide adequate protection from design basis feedwater transients. This assessment should re-confirm whether these plant designs meet the requirements of NRC regulations, using appropriate staff guidelines for acceptable means of meeting these regulations. This should include an evaluation of the safety margins of these plant designs to assure that specified acceptable fuel design limits are not exceeded as a result of feedwater transients.

With regard to feedwater transients in general, a recent review by the staff of feedwater transients occurring in PWR plants during the period from March 1978 through March 1999 shows the following results:

1. There were 9 B&W plants that had 27 feedwater transients or 3.00 per year, per plant;

2. There were 24 Westinghouse plants that had 44 feedwater transients or 1.83 per year, per plant; and,

3. There were 7 Combustion Engineering plants that had 13 feedwater transients or 1.85 per year, per plant.

The frequency of feedwater transients is not appreciably higher (about 60%) for B&W. The difference may be at least partially due to the initial operational life of the B&W plants as compared to Westinghouse and Combustion Engineering.

1.1 Study Objectives

The initial focus of the study was on the following B&W designed plants for which utilities hold operating licenses:

Three Mile Island, Units 1 and 2 (Metropolitan Edison Co.)
Davis-Besse, Unit 1 (Toledo Edison Co.)
Crystal River, Unit 1 (Florida Power Corp.)
Oconee, Units 1, 2, and 3 (Duke Power Co.)
Rancho Seco, Unit 1 (Sacramento Municipal Utility District)
Arkansas Nuclear One, Unit 1 (Arkansas Power & Light Co.)

The first objective was to make an early assessment concerning those measures that might be necessary to prevent a recurrence of the TMI-2 event at these facilities. In particular, consideration was given to the directives transmitted in Inspection and Enforcement Bulletins to utilities holding operating licenses for B&W plants to assure that implementation of the immediate measures required by the staff in those bulletins provide adequate protection pending completion of more intensive reviews.

A second objective was to make an assessment concerning additional remedial measures of a short- and long-term nature that might be necessary to correct design and operational deficiencies in B&W plants, including those not yet licensed to operate. A third objective was to identify weaknesses in the regulatory review process that contributed to the failure to anticipate the sequence of events that led to degradation of core cooling in the early phases of the TMI-2 accident.

1.2 Scope of Study

The assessment herein deals mainly with the generic implications of the initiating event at TMI-2; that is, the feedwater types of transients that could lead to an overpressure condition that opens a power-operated relief valve and could potentially result in a loss-of-coolant accident. Other aspects of the accident will be considered by other NRC task groups that will deal with such matters as post-accident monitoring, hydrogen control, operator actions, and emergency plans. The ACRS has met on several occasions to discuss and review the TMI-2 accident. It is continuing its review in conjunction with ongoing staff activities. Current reports from the ACRS dated April 7, 18, and 20, 1979, are enclosed as Appendices A, B and C.

Because of the need to complete this assessment in a short time, the scope of design and operational data used was limited to data essential to reaching the objectives stated above. The sequence of events that took place during the early part of the TMI-2 accident is sufficiently well understood that further refinements in the sequence (e.g., precise times when equipment started, stopped, or failed and when operators took specific actions) should not affect this study.

The results of this assessment are presented in seven major sections following this introduction.

Section 2 is a comparison of the general design features including configurations, sizes, and safety and control systems of B&W operating plants to determine areas of uniformity and difference. These are in turn related to plant characteristics that govern systems behavior under transient conditions.

Section 3 deals with B&W operational event reports that have been reviewed in which certain events of some similarity to those involved on the TMI-2 accident are discussed in the interest of determining whether we could or should have anticipated the TMI-2 event.

Section 4 deals with operating procedures and operator training in light of the TMI-2 event.

Section 5 treats the analyses presented in the Safety Analysis Reports and in response to specific licensing review questions. The Standard Review Plan is discussed in terms of whether current licensing requirements would have required analysis of a TMI-2 type event. The General Design Criteria and Technical Specifications are also considered relative to the event.

Section 6 summarizes briefly the considerations given to plant design features for feedwater transients in other pressurized water reactor (PWR) designs. This action provides some insight into the generic applicability of the preliminary findings made on B&W plants, as a result of the TMI-2 incident, to PWR plants designed by Westinghouse (W) and Combustion Engineering (C-E).

Section 7 relates to the IE Bulletin 79-05A. This bulletin provides a chronology of the event and identifies areas for immediate action by licensees to avoid a recurrence of this incident. Near-term action is focused in this area.

The evaluation by the task group is presented as a set of findings and recommendations for further action in each of the principal areas investigated. These findings and recommendations are given in Section 8.0 and will form the basis for more specific review by the staff, the reactor designers, and licensed utilities.

The operating B&W plants have been shut down to perform plant modifications that will increase the overall safety margins to accommodate feedwater types of overpressurization transients. Plant shutdowns are expected to last about a month to perform the following:

1. Improve the reliability of the auxiliary feedwater system (AFW).
2. Install a reactor trip on the secondary system.
3. Complete analyses of transients and small breaks.
4. Complete training based on the TMI-2 accident.
5. Analyze the integrated control system regarding its reliability.

These actions are necessary to ensure adequate safety margins for continued plant operation pending further long-term actions to restore the plant design and operational aspects to originally intended margins. The specific actions that are to be taken by each utility, except for the Metropolitan Edison Company, are stated in letters enclosed as Appendices D, E, F, G and H.

The conclusion is reached by the task group in the report that, although further studies and evaluations are in progress to understand all aspects of the TMI-2 accident, certain design improvements and other actions already being implemented due to the recent shutdown actions are necessary before plant operation can be resumed. These actions are being specified in the shutdown orders that resulted from this generic review; e.g., reactor trip on the secondary side of the plant, operator training, auxiliary feedwater reliability, and the need for further analyses of small breaks. These actions are already being taken in conjunction with the IE bulletins and the recent B&W plant shutdown orders. Copies of the currently available shutdown orders are enclosed as Appendix Y in this report. Longer term improvements are required as specified in this report.

1.3 Background Summary of the Three Mile Island Unit 2 Accident

At approximately 4 a.m. on March 28, 1979, the Three Mile Island Nuclear Plant Unit 2 (TMI-2), while operating at approximately 97 percent of full power, experienced a loss of feedwater that led to a turbine trip and then a reactor trip on high pressure. Subsequently, a series of events took place that resulted in significant damage to portions of the reactor core. Since the primary purpose of the current study is find ways to prevent a recurrence of the accident at TMI-2, an understanding of the course and consequences of the accident is necessary. The entire sequence of events is summarized below to place the study in perspective and to emphasize the importance of controlling "anticipated" operational occurrences before plant conditions degrade to a point where core-cooling capability is jeopardized. It is believed that equipment malfunctions, design failures, and human errors all contributed, to varying degrees, to the accident consequences.

The responses of the system parameters in the first several minutes of the accident are shown in Figure 1. In the time period up to about 30 seconds, the sequence at TMI-2 was generally normal for an anticipated feedwater transient and plant response was as expected. The power-operated relief valve (PORV) opened at approximately 3 seconds after turbine trip and the reactor tripped at approximately 8 seconds. The auxiliary feedwater system started up and should have delivered secondary coolant to the plant's two steam generators to remove heat; however, the flow paths were blocked by closed valves. Operator action to open the valves to

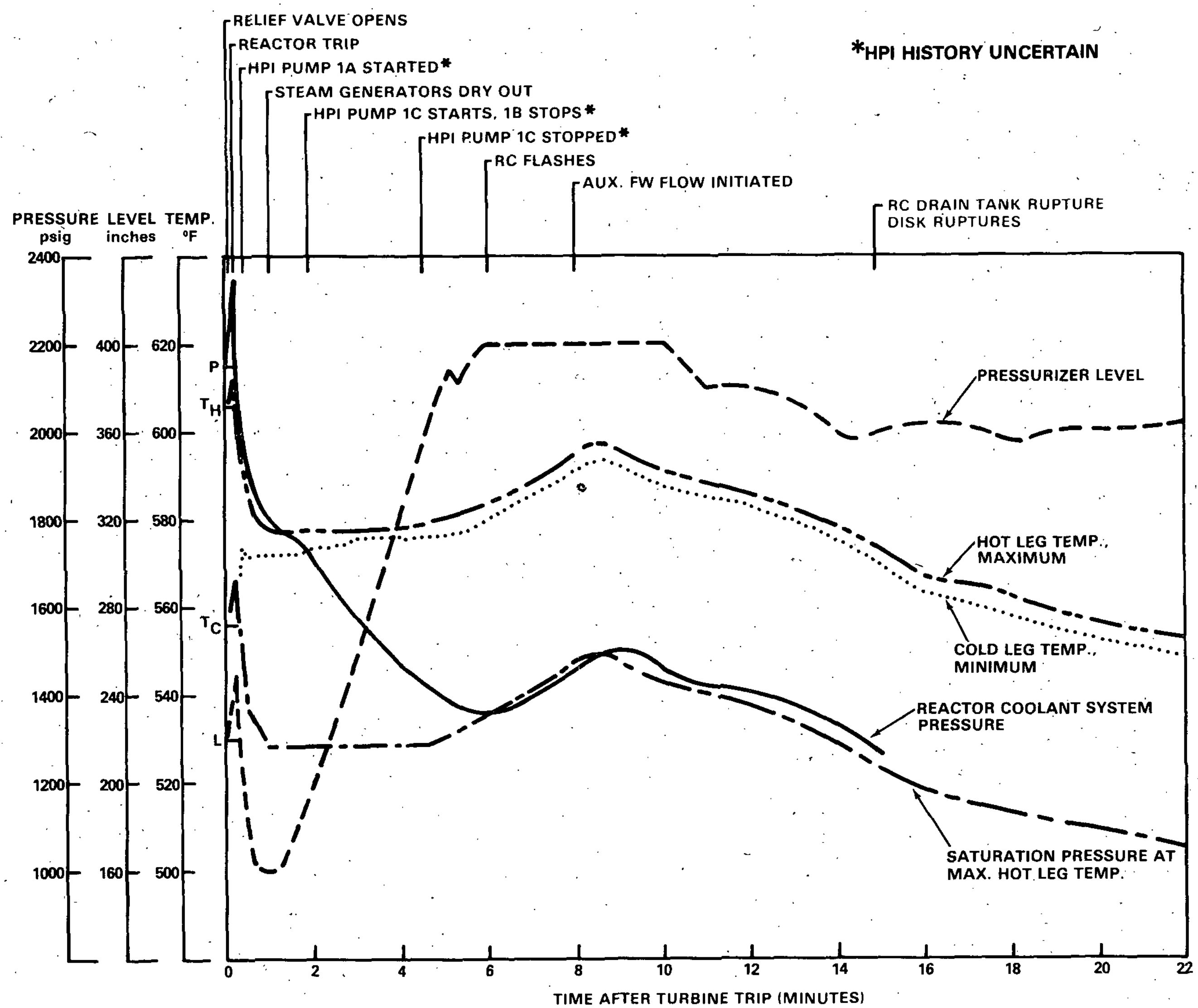


Figure 1. Reactor Coolant System Parameters in Minutes After Turbine Trip at Three Mile Island, Unit 2, March 28, 1979.

start auxiliary feedwater flow occurred approximately 8 minutes later. In addition, the PORV should have closed as reactor pressure decreased; however, it failed to close.

As the reactor pressure decreased to a preset value (1600 psi), the high-pressure injection (HPI) system started as designed and began to inject cold water into the reactor. At this time, an indication of rapidly rising pressurizer level apparently led the plant operators to take manual control of HPI, initially terminating flow, and subsequently throttling back to as-yet undefined flow rates. At this point, the Three Mile Island accident sequence had been under way for approximately 12 minutes.

The relief valve apparently remained open and the system temperature and pressure continued to fall while the pressurizer level remained high. After approximately 15 minutes, the reactor coolant drain tank, which receives the discharge from the relief and safety valves, became overpressurized and relieved through its rupture disk. The pressure within the containment then rose to about 2 psig. The containment was not isolated since automatic isolation is initiated at 4 psig, which did not occur until after nearly 4 hours. The reactor building sump pumps started automatically in response to the rising water level in the containment and discharged into tanks in the auxiliary building. These tanks became full and overflowed into the reactor building. The reactor building sump pumps were stopped after approximately 30 minutes.

Small LOCA

The sequence of events and system response for the next 15 hours are shown in Figure 2. Two of the three auxiliary feedwater pumps were shut off after 30 minutes. Except for short periods, one auxiliary feedwater pump or normal feedwater and one or two HPI pumps remained turned on from this time on. However, the flow from the HPI pumps was apparently throttled. The pair of reactor coolant pumps in one loop was turned off after approximately 70 minutes, apparently to prevent damage to the pumps. The secondary side of the steam generator in this loop was isolated, and the water level in the other steam generator was raised from 36 inches to approximately 250 inches or about 50 percent of the operating range.

The pair of pumps in the other loop was also shut off after approximately 100 minutes. Within 15 minutes, the reactor coolant system hot leg temperature began to increase rapidly and went off the scale at approximately 620°F. The cold leg temperatures continued to decrease. This large temperature difference continued for over 8 hours and is believed to be the period during which the severe damage to the core occurred.

The system pressure continued to decrease until nearly 2 1/2 hours after the turbine tripped; at that time the relief valve was isolated by closing a block valve. System pressure then increased to over 2100 psig. This block valve was intermittently opened and closed over the next 5 1/2 hours period. Pressurizer level and system pressure varied, but in general they remained high. After 7 1/2 hours, this block valve was opened and the system was depressurized over the next 4½ hours in an apparent attempt to start the decay heat removal system, which required the pressure to be below 400 psig. For reasons not known at this time, the RHR system was not placed into operation. However, the sequence of events shown in Figure 2 indicate that the pressure was never low enough to go on residual heat removal (RHR). The reactor building isolation and containment spray were actuated at about 9 hours, apparently because of the combustion of hydrogen in the containment.

The pressure remained between 400 and 600 psig from about 9 to 13 hours into the accident and the hot and cold leg temperatures began to converge near the end of this period. The block valve was closed after nearly 13 1/2 hours and the system repressurized to over 2300 psig. Nearly 15 1/2 hours after the onset of the feedwater transient, one reactor coolant pump was again started, the core inlet and exit coolant temperature nearly converged at approximately 280°F, and the reactor pressure was stabilized at approximately 1000 psig. Heat was transferred through one steam generator to the main condenser.

The reactor has remained in this condition with some small changes in pressure and with decreasing temperature during the past month. On Friday, April 27, 1979, the plant was placed in a natural circulation cooling mode with heat removal through the steam generator.

A detailed chronology of the accident was recently submitted by the licensee and is provided in Appendix I. NRC investigation of the accident, including verification of the sequence of events, is continuing.

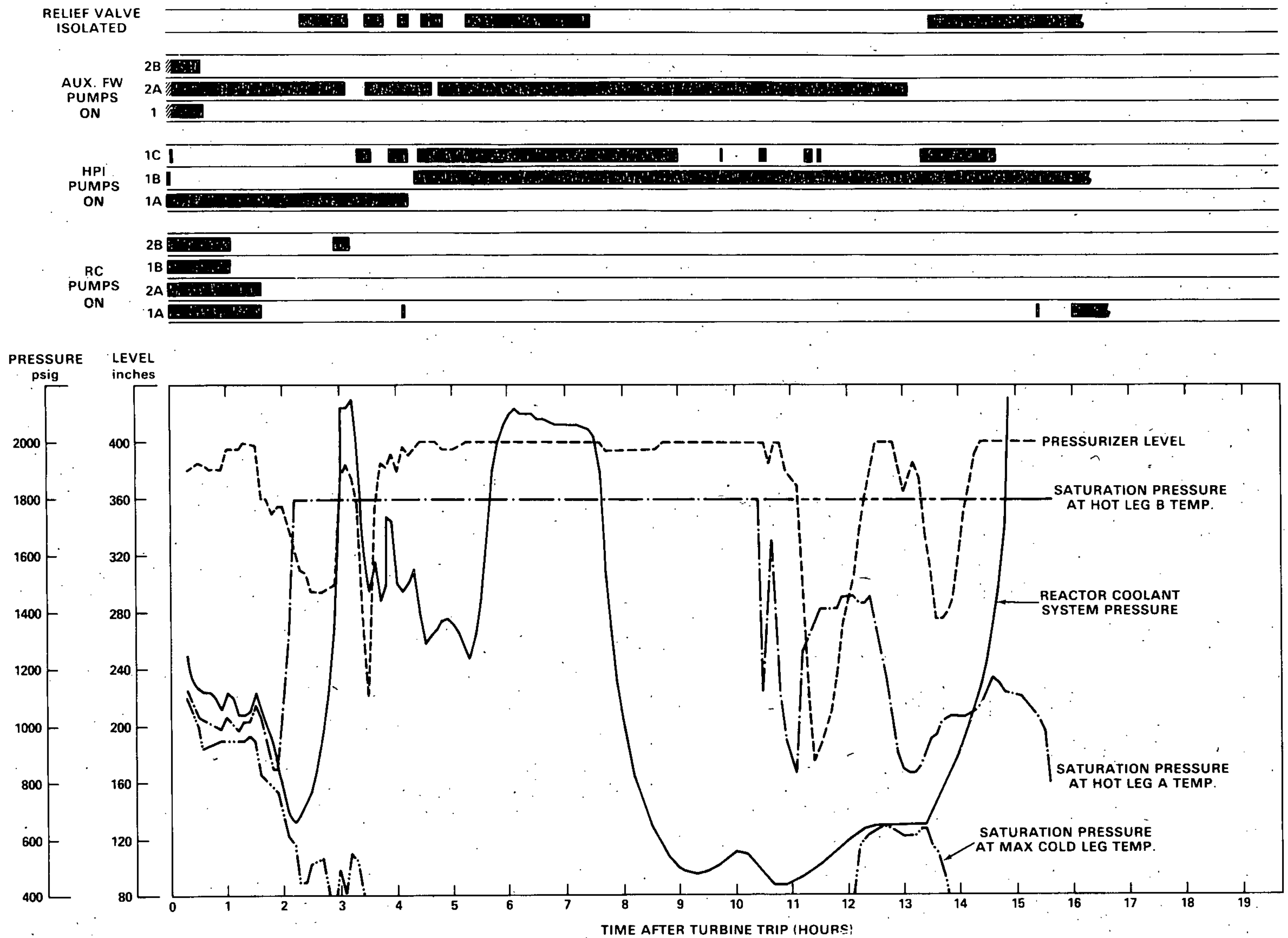


Figure 2. Reactor Coolant System Parameters in Hours After Turbine Trip at Three Mile Island, Unit 2, March 28, 1979.

2.0 B&W PLANT COMPARISON

2.1 General Features

This section provides a brief comparison of currently operating B&W plants. The information was obtained in part from Final Safety Analysis Report (FSAR) data and from licensees. Some of the information is provided here in tables and serves as useful reference material. The interactions of balance-of-plant (BOP) interface has not been completely evaluated in this report.

Reactor coolant systems (RCS) designed by Babcock & Wilcox typically consist of the reactor vessel, two vertical once-through steam generators, four reactor coolant pumps with three-stage mechanical seals, and one electrically heated pressurizer. The system is arranged in two heat transfer loops, each with two reactor coolant pumps and one steam generator. Figures 3 and 4 provide plan and elevation views of the primary reactor coolant system arrangement. These are typical for all but one of the currently operating B&W plants. Davis-Besse 1 is the first of a series of "raised loop" configurations. This type of configuration is shown in Figures 5 and 6. The raised loop configuration was initially introduced to improve performance characteristics subsequent to a loss-of-coolant accident and to permit exclusion of the vent valves in the reactor core barrel. The vent valves have been retained in the design, although the number was reduced from eight to four valves. In addition to providing improvement in natural circulation characteristics, the raised loop configuration provides mechanical design and support configuration improvements. In September 1977, Davis-Besse 1 experienced an event similar to the TMI-2 event but from a lower power level. As discussed in Section 3, the plant response was similar to that at TMI-2, but saturation conditions were terminated by the operator using the block valve before core damage occurred.

VRCS : Vnom in DB different

The significant characteristics of the B&W plant design relative to the severity of the heatup pressurization phase of the transients is the relatively small water inventory in the steam generators during power operation. Rapid boiloff of this inventory following loss of main feedwater supply results in a rapid loss of normal RCS heat sink. This causes a relatively rapid pressurization of the RCS in the first few seconds of the transient. Automatic actuation and delivery of auxiliary feedwater supply to the steam generator does not substantially lessen this RCS heatup/pressurization due to its limited capacity and time delays.

With regard to code safety valve actuation for a B&W plant, although the FSAR would predict that the valves would lift (since calculated RCS transient pressure exceeds the set point), this may not occur in every case.

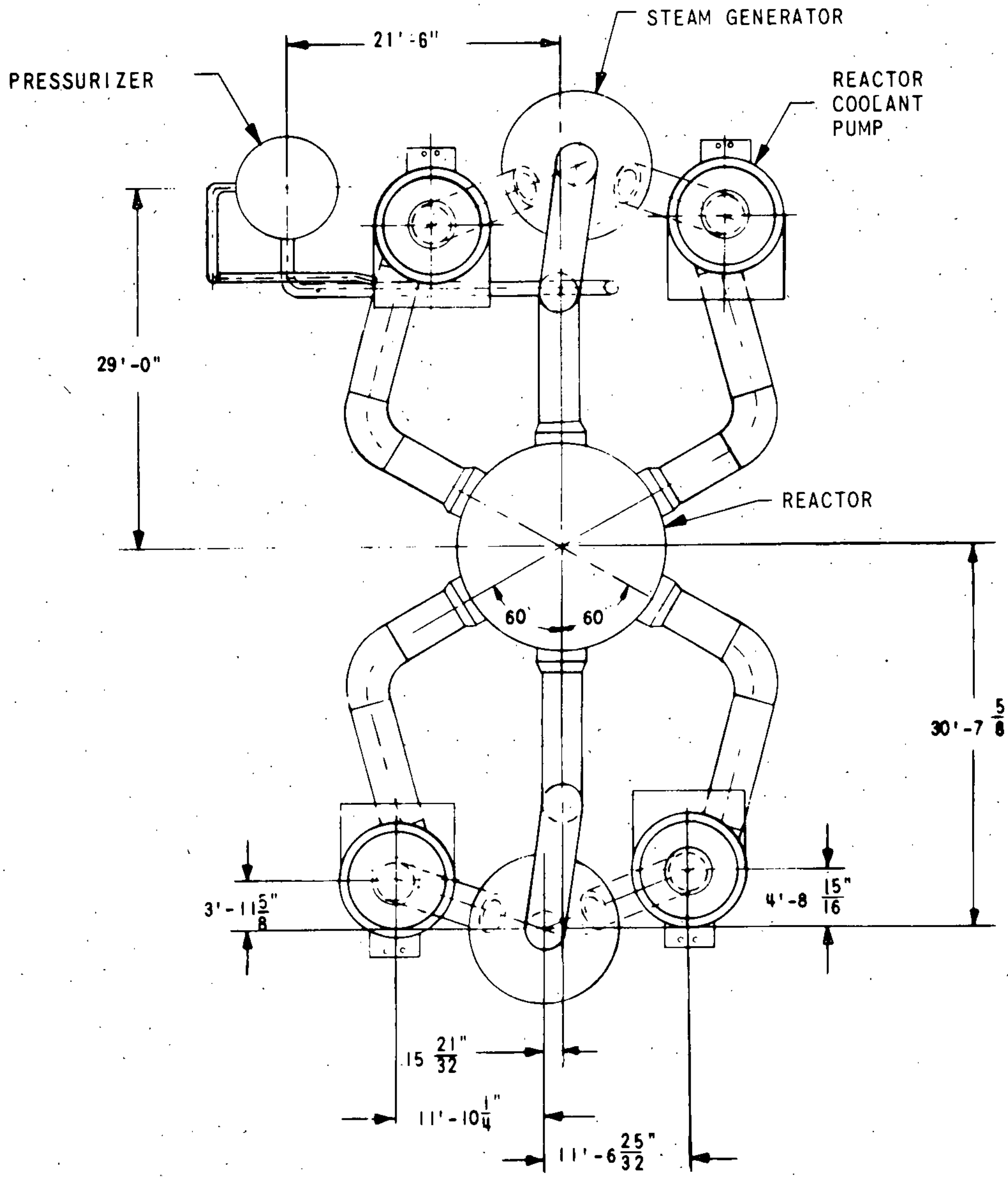


Figure 3. Reactor Coolant System Arrangement - Plan, from Three Mile Island, Unit 2, FSAR.

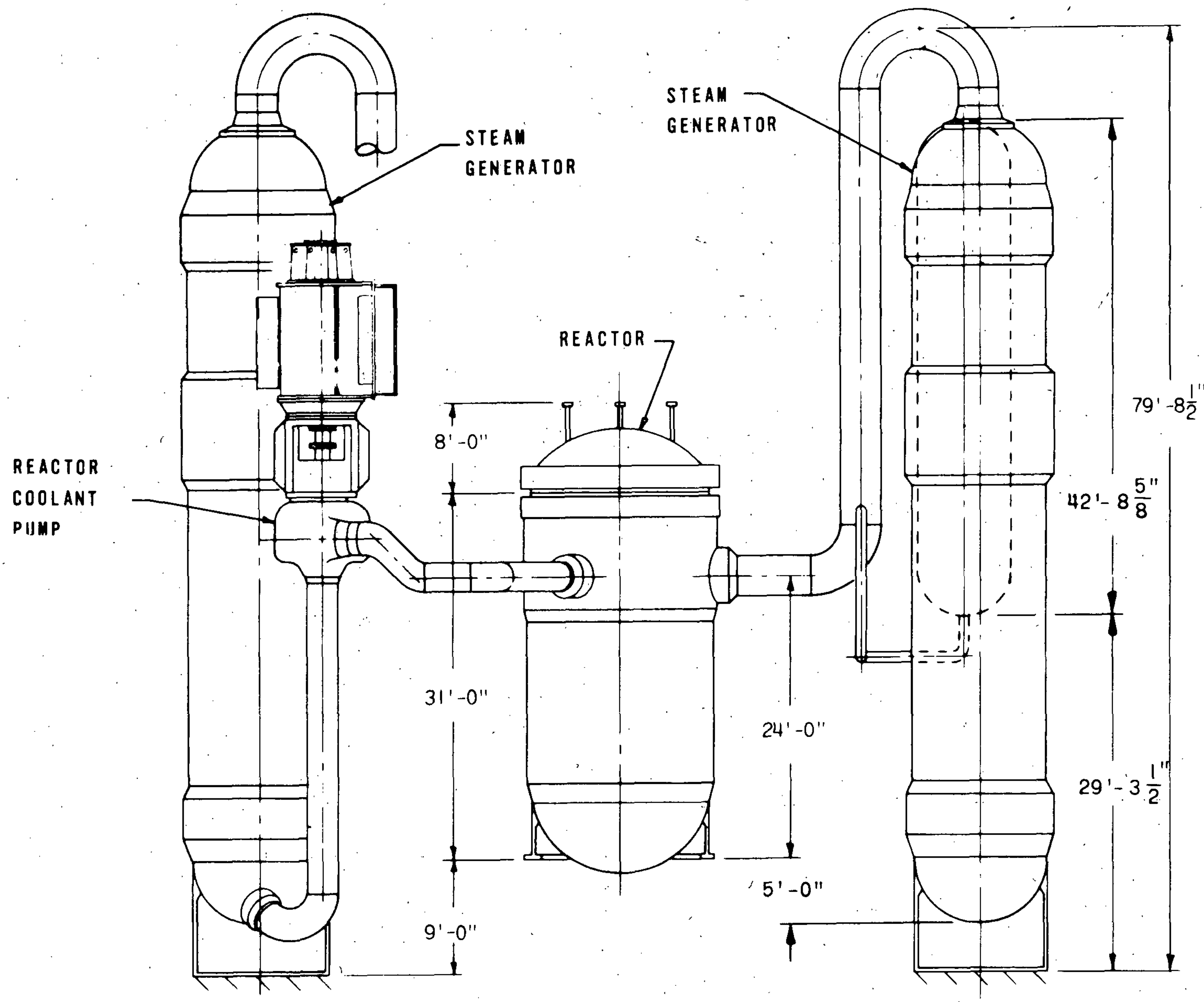


Figure 4. Reactor Coolant System Arrangement - Elevation, from Three Mile Island, Unit 2, FSAR.

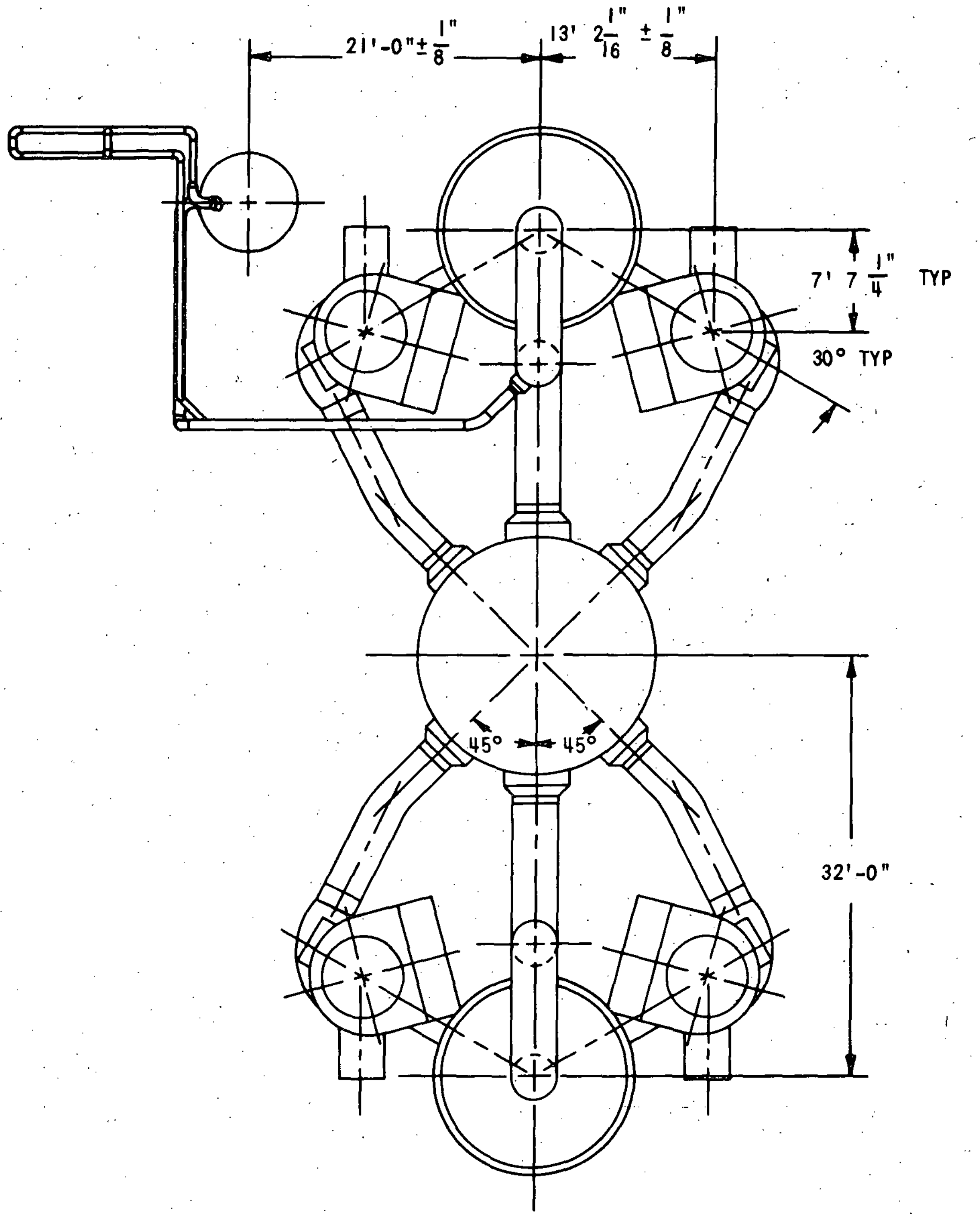


Figure 5. Reactor Coolant System Arrangement - Plan, from Davis-Besse, Unit 1, FSAR.

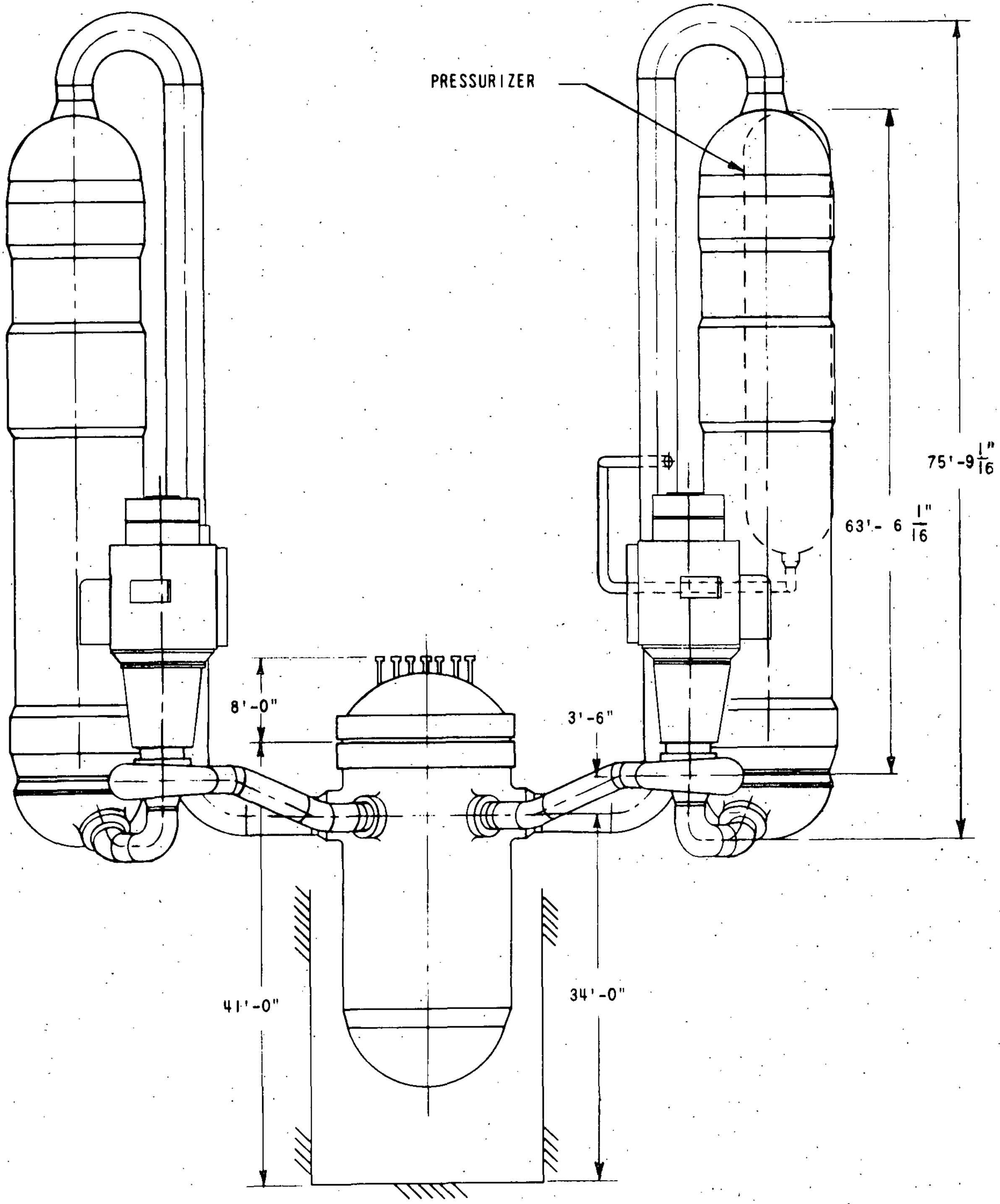


Figure 6. Reactor Coolant System Arrangement - Elevation, from Davis-Besse, Unit 1, FSAR.

Considering the combination of the relatively small steam generator water inventory, lack of a direct reactor trip on secondary side conditions and relatively small margin between normal operating pressure and PORV set point, it must be anticipated that PORV actuation could occur everytime a loss of feedwater event occurred. Some plant operating procedures (e.g., Oconee Units 1, 2 and 3) require a "soft-wired" operator action to trip the reactor immediately in a loss of feedwater. This action, if fast enough, could prevent PORV actuation. The recent actions taken by the staff to require changes in the B&W operating plants here substantially reduced the likelihood of actuating the PORV in such transients. B&W plants are now required pursuant to the shutdown orders to have a reactor trip originated by steam plant parameters (e.g., low steam generator level, loss of feedwater pumps, turbine trip). Such a trip would delay PORV opening a few seconds and further increase the margin against steam generator boil-off. In addition, the RCS high-pressure reactor trip set point will be lowered. Thus, the complications that arose at TMI-2 from a stuck-open PORV are reduced in the B&W plants.

2.2 Design Characteristics of B&W Operating Plants

2.2.1 Principal Design Characteristics

Key characteristics of the B&W plants are listed in Table 1. The core thermal power ratings vary from 2452 MW to 2772 MW although the core sizes and configurations are essentially the same. The primary coolant system volumes are also essentially the same. The pressurizer represents about 13 percent of the total system volume. The role and sizing of the pressurizer for normal and off-normal operating conditions should be better understood, especially with regard to its interactions with the once-through steam generator (OTSG) and integrated control system (ICS) of the B&W plants.

In all B&W plants, power-operated relief valves on the pressurizer are set to relieve at 2255 psig. The valve for Davis-Besse 1 was manufactured by Crosby whereas those for the other plants were Dresser valves. Two code safety valves are installed on the pressurizer in each plant. In various plants, the set points for those valves range from 2435 to 2500 psig. In response to IE Bulletin 79-05B, licensees were directed to modify of the high-pressure scram set point and the PORV opening set point such that a reactor scram will preclude opening of the PORV.

The high-pressure injection (HPI) pumps were made by four different manufacturers. Other than Davis-Besse 1, each of two HPI would provide 450 gpm at 1600 psig (emergency core cooling system actuation on low primary system pressure). Only Davis-Besse 1 has the unique features of separate makeup and high-pressure injection pumps. The HPI pumps, while providing only 200 gpm each at 1600 psi, would provide significantly more flow against lower back pressure. The pump shut-off heads (4000 ft) would not lift the power-operated relief valves.

TABLE 1 COMPARISON OF KEY CHARACTERISTICS OF OPERATING B&W PLANTS RELATIVE TO THE LOSS OF FEEDWATER TRANSIENT

B&W Plants	Core Thermal Power, MWt	RCS Volume, ft^3 x 10^{-3} (inc. pressurizer)	Vol. of Pressurizer/Vol. of RCS	PORV Capacity, lb/hr/MWt/Setpoint, psi (to be revised per IE 79-05B)	PORV Manufacturer/Model No.	SV Combined Capacity, lb/hr/MWt/Setpoint, psi	High Pressure Injection Pump Characteristics: Shut Off Head, ft	High Pressure Injection Pump Characteristics: Gpm @ 1000 psig	High Pressure Injection Pump Characteristics: GPM @ 1600 psig	High-Pressure Injection Pump Manufacturer	OTSIG Inventory Minutes to Boiloff @ FP 641 Btu/lbm	RCP Vapor Trap Geometry (Ω)	Candy Cane Elevation from Hot Leg, ft	Internals Vent Valves	Hi Press. Trip Setpoint, psi (to be revised per IE 79-05B)	Direct Trip from Secondary Side (to be revised per IE 79-05B)
TMI-2	2772	11.5	0.130	40.4 / 2255	Dresser 315 33VX	249 / 2450	6500	@ 500 ea	@ 450 ea	Bingham	0.45	Yes	45	Yes 8	2355	No
Crystal River	2452	11.5	0.130	40.8 / 2255	Dresser 315 33VX	254 / 2500	6500	@ 500 ea	@ 450 ea	Bingham	0.50	Yes	47	Yes 8	2355	No
Oconee 1,2,3	2568	11.5	0.130	41.7 / 2255	Dresser	254 / 2500	7000	@ 500 ea	@ 450 ea	Ingersall-Rand	0.48	Yes	47	Yes 8	2355	No
Rancho Seco	2772	11.5	0.130	40.4 / 2255	Dresser	249 / 2500	7000	@ 500 ea	@ 450 ea	B-J	0.45	Yes	47	Yes	2355	No
Davis-Besse	2772	11.5	0.130	40.4 / 2255	Crosby HPN-SN	242 / 2435	4000 MU 6500	@ 700 ea	@ 200 ea	B&W Canada	0.45	Yes	71	Yes 4	2355	No
ANO-1	2568	11.5	0.130	38.9 / 2255	Dresser	234 / 2500	7000	@ 500 ea	@ 450 ea	B-J	0.48	Yes	47	Yes	2355	No
TMI-1	2535	11.5	0.130	38.9 / 2255	Dresser	243 / 2435	6500	@ 300 ea	@ 450 ea	Bingham	0.48	Yes	47	Yes	2355	No

The once-through steam generators are all essentially the same. The secondary-side feedwater inventory is a function of power level, but all generally operate within the same range. Table 1 indicates that the time to boil-off from high water level is approximately 0.5 minutes at full power.

In general, the emergency feedwater systems (auxiliary feedwater) consist of combinations of steam turbine-driven and motor-driven pumps capable of 100% capacity with at least one pump out of service. Table 2 provides a summary for each plant and indicates design differences.

During normal power operation, the water level in the once-through steam generator (OTSG) varies with load. With auxiliary feedwater, the level is controlled at about 30 inches unless all reactor coolant pumps are lost. With loss of reactor coolant pumps, steam generator level is automatically raised and controlled at a higher level to promote natural circulation. As may be noted, this higher level ranges from 120 to 318 inches among the plants. This should be an area of further study and should include the interactions with sizing of the pressurizer and the ICS.

In all B&W plants, the reactor coolant pumps are located above the centerline of the cold leg piping as it enters the reactor vessel. This is referred to as vapor trap geometry (Ω) in Table 1.

The surge line to the pressurizer is "manometer" shaped due to its looped configuration; this configuration can contribute to false indication of water level in the RCS since the only level instrument measures level in the pressurizer. "Candy cane" elevation refers to the rise of the hot leg from the elevation leaving the reactor vessel to where it loops back down to the steam generator. As noted in the tabulation in Table 1, all the B&W plants have this feature. Possible means and the need to vent these high elevations are being considered by B&W and the staff.

The internals vent valves are check valves inside the reactor vessel that open to equalize pressure should the hot leg pressure exceed the cold leg pressure under post-LOCA conditions.

The overall configuration of the B&W RCS has a propensity toward void collection in high elevations that may affect the ability for natural circulation cooling; However, tests and recent experience at TMI-2 show that natural circulation cooling can be effectively achieved.

Prior to changes required by the IE Bulletins, the power-operated relief valve would open at 2255 psig, the reactor would trip at 2355 psig, and the code safety valves would open in the range from 2435 to 2500 psig.

TABLE 2 AUXILIARY FEEDWATER COMPARISON

Auxiliary Feedwater System	Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1	TMI-2
Auto FW Isolation Signal	None	Steam line failure matrix. Closes FW block valve at P<600 psig. (Includes faulted steam generator only.)	MSL failure-logic: Isolated main FW from faulted SG at P<435 psig	Steam & FW rupture system (IE) 1. Steam P-FE P≤170 psi 2. Steam generator low level 3. Loss of all RCPs (power monitor) 4. Low steam generator pressure (600 psig) 1. or 2. or 4. isolates main FW to both SG's, closes MSIV's 4. also aligns both AFW PPs to the good SG. 1. or 2. or 3. or 4. starts both AFW PPs	steam line break inst. & control (SLBIC) isolates both steam generators main FW & MSIVs at <600 psig in either S.G. Do not isolate emergency EFW. (SLBIC is IE)	Loss of four RCP, both MFWP, discharge pressure of MFWP
Auxiliary Feedwater					System is seismically designed. Valves are Class IE; most instr. is not IE.	
Pumps: Type/no./strainers	(Emergency FW pumps) Located turbine bldg. 2 floors under grade. centrifugal/1 per unit/No	Located near grade level in intermediate bldg. (Seismic category I). Centrifugal/2/No	Located at CST in enclosure centrifugal/2/No	Does not start on SFAS. centrifugal/2/suction strainers	"EMERGENCY" FW on this plant centrifugal/2/none	Centrifugal
Drive: Type	Steam driven	1-motor driven 1-steam driven	1-motor driven 1-motor & turbine tandem	(800 hp) turbines (Terry/Woodward)	1-turbine (Terry) 1-motor (Normal suppl supply not Class IE. Can be put on Class IE-15 mins.)	2-motor driven 1-steam driven

TABLE 2 AUXILIARY FEEDWATER COMPARISON (Continued)

Auxiliary Feedwater System	Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1	TMI-2
Supply/exhaust	Main steam/atmosphere (≥10 min.)	Motor: Class 1E; Main steam either SG upsteam MSIV/Atmosphere	Motors-Class 1E; steam from MSL/atmosphere	Main steam/atmosphere	Main steam/atmosphere	Main/atm.
Orientation of pumps (self venting)	Horizontal; yes (low point in system)	Horizontal; possibly not self-venting. Elevation same as bottom of condenser	Yes-thru mini-flow recirc. line	Horizontal (yes)	Horizontal/yes (low point in system)	Horiz.
Capacity	1080 gpm at 1065 psia	740 gpm each @ 3000 ft	motor 840 gpm @ 2700 ft turbine 840 gpm @ 2650 ft	1050 gpm @ 2500 ft (250 gpm of this is recirc)	780 gpm @ 2600 ft	1. 470 gpm @ 2560 ft 2. 940 gpm @ 2600 ft
Shutoff head	1465 psia	Motor: 3400 ft Steam: 3500 ft	Steam: 3050 ft @ 3560 rpm Motor: 3100 ft @ 3560 rpm	~3150 ft @ 3600 rpm	--	--
Suction sources/ seismic category	1. Upper surge tank/no; ASME VIII 2. Hotwell/no; aux. SW pumps (3000 gpm @ 75 psig) (from emergency power, 1 per site) suction from CW intake located in aux. bldg. 1 floor below grade	1. CST/No. ASME Class 3, B31.1 2. Hotwell/no-These suction valves interlocked with vac. brkr. valve position 3. Makeup from fossil units demin./no (1 min)	Condensate storage tank - Seismic Cat. 1 canal-non-seismic (5 min.) reservoir-non-seismic	1. CST/no (auto XFER to SW on low suction P-Class 1E, redundant instr.) 2. Deaerator/no 3. Fire water system/ no last: SW pump discharges/yes	1. CST/no 2. SW pp disch./ Yes; suction press. switch (common-non-class 1E) remote manual MOVs (requires only seconds to switch-Class 1E valves)	Condensate storage tank
Turbine-driven pumps operable at what range of steam press.	≥300 psig	≥200 psig	>213 psig (tested 1124 gpm at 213 psig)	>50 psia (Psat for 280°F)	≥270 psig	200/435 psig
Trips	1. Overspeed 2. Low hydraulic pressure (shaft-driven pump)	Overspeed/motor trips on closed suction valve. Overcurrent	Manual (local or remote) Bus unloading Overcurrent: Inst 2000A OST; 4450 rpm, 960 for 5.15 sec, 640 for 6.43 320 for 11.39	OST; low suction P; low steam inlet P at >25 sec.; manual	Turbine-OST; motor-none	Turbine OST; overcurrent

TABLE 2 AUXILIARY FEEDWATER COMPARISON (Continued)

Auxiliary Feedwater System	Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1	TMI-2
Instrumentation	EFW pp disch. press. & flow; SG level; SG pressure	Driven turbine SV position; motor on-off lights; flow in SU FW line; ammeter	On-off lights for motor drive; ammeters; steam supply valve position	Each pump: discharge press; speed indication	Discharge press. each pump	SG Level; on-off lights; low suction on pumps
Normal lineup	Suction valves from tank; open disch. valves N.O. (check valves prevent backflow)	All injection valves N.O. (check valve prevent backflow)	FCVs & bypasses N.C./ Cross-tie N.O; suction from CST:N.O.	Suction valves N.O. from CST; two series MOV's closed in each pump's discharge. One pump feeds one S.G.	Discharge valves (MOVs-Class 1E) Closed. Cross-tie valves open.	--
Auto initiation	Loss of both main FW pumps (detected by discharge header press. <750 psig or FW pump turbine stop valve position). EFW does not start on ECCS.	Loss of both main FW pumps (as indicated by low control oil pressure). AFW does not start from ECCS initiation. Motor-driven pump, no auto start	Loss of both main FW pumps <850 psig on each pump disch.) These switches reset but pumps cont. to run. (Single fail. proof) All RCPs off (Power monitor-current volts, phase-same as RPS). Turbine only starts on ECCS initiation	Steam & FW rupture control system (see description under auto FW isolation) Does not start on SFAS.	Turbine: 1. SLBIC (see Auto FW Isol.) 2. Loss of FW sensed by governor latch on main pumps and "auxiliary" FW pump low disch. press (thru ICS) 3. loss of all RCPs (breaker position) Motor: No auto start (No starts on ECCS)	--
Failure mode on loss of air/power	Loss of air switches 14 in. main header. Valves & solenoids to batteries (non-class IE)	FCVs lock in position reservoir for 3 cycles/ emergency buses	Class 1E MOV bypasses FCV on SFAS. FCV fail open/FCV fails to 50%	No air-op. valves/MOVs fails as is, but all are powered by Class 1E instr.	No air. op. valves/ as-is ... (all valves are MOVs)	AC supply to solenoid back up by battery thru inverter
ICS control level: RCP/no RCP	25 in./260 in. sensed from breaker position	30 in./250 in.	30 in./~318 in.	Not ICS. Auto essential level control system 120" from redundant, Class 1E instrumentation (pump speed)	20 in. & 24 in./~300 in. (50% op. range)	625 in./ 590 in./ 382 in.

TABLE 2 AUXILIARY FEEDWATER COMPARISON (Continued)

Auxiliary Feedwater System	Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1	TMI-2
Surveillance test method	Close manual AFW supply block valve. Recirc from/to upper surge tank. Valves do not realign automatically on SFAS	Close discharge MOVs and recirc from/to CST thru mini-flow line. Valves do not realign automatically on SFAS	Close FCV & x-tie from C.R. pump from CST to cond. through test line. Valves do not realign automatically on SFAS	From CST to drain thru normal recirc line (250 gpm). No valve realignment necessary	Recirc. to condenser or CST. Injection valves already closed. Operator opens the manual valve	--
Steam generator: distance between tube sheets/AFW inlet/main feedring	625 in./590 in./ 362 in.	625 in./590 in./ 382 in.	625 in./603 in./ 338 in.	625 in./608 in./ 388 in.	625 in./590 in./ 382 in.	--
Method to protect good SG	Operator action from control room	Steam line failure matrix isolates all FW from SG if P<600 psig	Main steam line failure logic (<435 psig isolates SG). Does not isolate AFW	Steam & FW rupture control system (see description under auto FW isol.	SLBIC (see auto FW isolation). Does not isolate EFW	--

Prior to the TMI-2 accident, there were no reactor trip signals generated by turbine trip or low steam generator water level in any of the B&W plants. However, the licensees of the B&W plants are installing a reactor trip that would be actuated by a turbine trip or loss of feedwater.

2.2.2 Thermal Hydraulic Design Subcooling Margin

The steady-state thermal hydraulic designs of several B&W, Westinghouse, and Combustion Engineering reactors have been compared to assess the relative margin to coolant saturation during depressurization events. Because a reactor is normally tripped early in such an event, the average coolant subcooling provides a reasonable measure of the margin.

Table 3 lists the average coolant temperature relative to saturation at the initiation pressure of the high-pressure injection system of several plants. Although the plants with low subcooling have the least margin to flashing, flashing is not expected prior to actuation of any of the HPI systems. For a stuck-open relief valve or for a system with heat removal capability within the steam generator, the core average coolant temperature will drop early in the transient and remain below saturation prior to high-pressure injection.

For B&W plants, the high point of the hot let piping is considerably higher than the core outlet elevation. This elevation difference results in a difference in saturation temperature of about 2°F between the core outlet saturation temperature and the minimum saturation temperature in the hot leg for lowered loop plants such as TMI-1, TMI-2, and Rancho Seco. For the raised loop design of Davis-Besse 1 or BSAR-205, the difference in saturation temperature is about 3°F. For TMI-2, flashing should have occurred approximately 30 seconds earlier at the top of the "candy cane" than at the core outlet. Thus, flashing should not have occurred even at the top of the "candy cane" until well after the initial pressurizer surge and well after initiation of high-pressure injection.

For Westinghouse and Combustion Engineering plants, the high point of the flow loop is inside the steam generator and the primary water is cooled sufficiently to prevent flashing in the steam generator prior to flashing at the core outlet. Thus, flashing will not affect the actuation of the high-pressure injection system for these plants either.

2.2.3 Main Feedwater Systems

The main feedwater systems among the nine licensed B&W plants are functionally very similar. The plants used both GE and W turbine generators and the nine plants were designed by four engineering firms. Table 4 provides an indication of the similarities and differences. The loss of feedwater at TMI-2 has been attributed to difficulty with the condensate demineralizer. The following discussion of condensate

TABLE 3 COMPARISON OF PRIMARY THERMAL-HYDRAULIC PARAMETERS

Vendor	B&W					W		C-E
Reactor	TMI-2	TMI-1	Rancho Seco	Davis-Besse	Oconee 1	H.B. Robinson	Trojan	Calvert Cliffs 1 & 2
Design power, MWt	2772	2568	2772	2772	2568	2192	3411	2560
T_{In}, °F	557	554	557	555.4	554	546.2	552.5	543.4
$T_{Out.}$ core, °F	610.6	606.2	610.6	611.7	606.2	604.5	619.4	597.4
$T_{Out.}$ vessel, °F	607.7	603.8	607.7	608.6	603.9	602.1	616.7	595.4
Core pressure, psia	2200	2200	2200	2200	2200	2250	2250	2250
Core flow 10^6 lb/hr	137.8	131.32	137.8	131.32	131.32	101.5	126.7	117.5
Core flow area, ft^2	49.17	49.17	49.17	49.17	49.17	43.75	51.1	53.5
HPI injection pressure, psia	1615	1515	1615	1615	1500	1715	1765	1578
Coolant sub-cooling at injection pressure, °F	24.0	18.8	24.0	24.3	17.4	40.4	34	33.8
Subcooling at core outlet normal, °F	39.0	43.4	39.0	37.9	43.4	48.4	33.5	55.5

TABLE 4 MAIN FEEDWATER SYSTEMS

Main Feedwater Systems		Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1[a]	TMI-2
Pumps:	Type	Centrifugal (2)	Centrifugal (2)	Centrifugal (2)	Delaval pumps with GE turbine drives centrifugal (2)	Also aux. FW PP, centrifugal (2) Bingham pumps with turbines	Centrifugal
	Capacity	~75% full power (normal total flow at 375°F 25,000 gpm at 1060#)	13,300 gpm each at 2280 ft	~6 x 10^6 lbs/hr (at full power)	15,000 gpm @ 2150 ft (5150 rpm)	14,750 gpm @ 1901 ft	15,500 gpm at 2240 ft
	Shutoff head	1253 psia	2550 ft	3200 ft	2560 ft	1090 psig	
Drives:	Type	Steam	Steam	Steam	Steam	Steam	Steam
	Supply/exhaust	1. Extraction steam (auto transfer) 2. Main steam header 3. Aux. steam (any unit)/main condenser	Two normal sources (reheat & main) into governor. Backup from aux. steam header (manual)	(Reheat steam, aux. steam) main steam/ main condenser	1. Reheat steam 2. Main steam 3. Aux. steam/main condenser	Reheat steam, main steam/main condenser	Bleed-Main Main/ condenser
	Trips	1. Low suction press. (~300 psig) 2. Hi. disch. press. (1275 psig) 3. Low oil press. (control or lube) 4. Low oil sump level (common sump) 5. O.S.T 6. Thrust brg. wear 7. Oil fire trip (temp) 8. Low exhaust hood pressure 9. Loss of all booster pumps (electrical) 10. Manual trips	1. All booster pumps tripped (disch. press.) 2. Suction or disch. valves 40% closed 3. Low bearing oil press. 4. Loss of tripping power 5. High exhaust hood P 6. High exhaust hood T 7. Manual trips	1. Hi disch. press: 1650 psig inst. or 1575 for 5 sec. 2. O.S.T. 5850 rpm 3. Low oil press: control or lube 4. Thrust brg. displacement 5. Manual trips	1. High disch. press. 2. Overspeed 3. Low oil press: lube or control 4. Thrust brg. displ. 5. Manual	1. High disch. 2. Overspeed 3. Low oil press. (common) 4. Thrust brg. displ. 5. Low suction pressure 6. Vibration 7. Manual	1. Low suction pressure 2. OST 3. Low brg. oil press. 4. High dischg. press. 5. Manual trip Note: List not verified.

[a] ANO-1 has an unusual source of normal FW in addition to their two steam driven main FW pumps. They have a motor-driven (non-safety grade) pump designated auxiliary FW pump. Its capacity is 1150 gpm @1100 ft. It is used for startup operations up to ~5% power.

TABLE 4 MAIN FEEDWATER SYSTEMS (Continued)

Main Feedwater Systems	Oconee	Crystal River	Rancho Seco	Davis-Besse 1	Arkansas 1[(a)]	TMI-2
Condensate Pumps: No./Strainers	3/yes (suction) (hotwell pumps)	2/none	3/None	3/suction strainers	3/suction strainers	3 pumps 3 suction strainers
Demineralizers: No./No. for Full Power/Mfg.	5/4/Graver	6/5/Graver	9/8/Cochrane	4/3/Delaval	6/5/L.A. water conditioning	-
Bypass/Operation/ Fail Position	Yes/(air op. valve) auto on hi ΔP (40 psid)/open	Yes/auto on hi ΔP (65 psid)/anywhere (air to both sides)	MOV/local only/ as-is (ΔP alarm)	Yes/(air op. valve) auto on high ΔP/open	Yes/manual/N.A.	Yes/MOV/as-is
FW Heaters: Bypass/ Operation/Fail Position	Yes/manual/NA	Yes on HPs; No on LPs /remote manual/ as is	Yes/manual/NA	Yes/remote manual MOV/as-is	Yes/manual/N.A	Yes/MOV-remote/as-is
Booster Pumps: No.	3 (shutoff head ~700 psia)	2	-	Same shaft as main FW PPs but 2 geared down to 1780 rpm (500 ft. hd.)	None	3
MSIV: No./operator type/Fail Position	None	4/air/close on loss of air	None	2/air (each valve has reservoir) closed	2/air/closed (each valve has reservoir	4
Auto Isolation	NA	Steam line failure matrix	NA	Yes	Yes	Yes

demineralizers is indicative of the diversity of design of various feedwater subsystems; however, it must be realized that there are other initiations, both human and equipment failure, that would lead to a loss of feedwater transient.

Normally, all condensate is processed through the demineralizer (full flow). Periodically, the pressure losses through the demineralizers become excessive. The flow is then bypassed around the demineralizer while it is being serviced. Some minor differences in the demineralizer bypass valve control are discussed below:

Oconee 1, 2, and 3
The condensate demineralizers are automatically bypassed by an air-operated valve (fail open) on high differential pressure across the demineralizers (40 psig).

Crystal River 3
The condensate demineralizers are automatically bypassed by an air-operated valve on high differential pressure across the demineralizers. This valve could fail in any position on loss of air because it uses air as a motive force in both directions.

Rancho Seco
There are no automatic bypasses for the condensate demineralizers. There is a locally actuated motor-operated valve that would fail "as-is" on loss of power.

Davis-Besse 1
The demineralizers would be bypassed automatically by an air operated valve on high demineralizer differential pressure. It would fail open on loss of air.

Arkansas 1
A manual bypass valve is provided for the demineralizer.

TMI-2
A motor-operated valve is provided to bypass the demineralizer. The pressure drop is indicated in the control room. The switch for the bypass valve is located behind the control panel. The valve would remain "as-is" on loss of power.

Only one aspect of the main feedwater system has been addressed above. This would indicate that there is variation among B&W plants in the control of a variable that can lead to loss of feedwater events. It is recommended that study of the main feedwater system design, operating procedures, and service procedures could lead to means to a reduce the frequency of loss of feedwater events.

2.2.4 Auxiliary (Emergency) Feedwater Systems

The auxiliary feedwater systems vary in design, apparently due to the individual approaches of the several different architectural engineers used by B&W reactor owners (see comparison Table 2). The comparison in Table 2 was made prior to the recent action taken on B&W plant shutdowns. Included in these actions will be an upgrading of the reliability of the feedwater systems. The principal elements of the various auxiliary feedwater designs, except for TMI-1 and TMI-2, are briefly summarized below (detailed discussions for each plant, except for TMI-1 and TMI-2, are provided in Appendices J, K, L, M and N).

Oconee

This plant has one steam-driven centrifugal pump per unit, with suction from sources that are not designed to seismic Category I (no seismically qualified source of water during a seismic event). Auto start occurs on loss of both main FW pumps (detected by discharge pressure below 750 psig or feedwater turbine stop valve position). The equipment for these two auto start signals does not meet single failure criteria. There is an auxiliary service water pump (3000 gpm at 75 psig) from Class 1E bus, with one pump for all three units. Because of its low discharge head, it is not a suitable backup to the auxiliary feedwater system. On loss of air, it switches to a 14-inch main feed ring. On loss of power, the valves and solenoids powered by batteries (non-1E) are not safety grade. There is no auto feedwater isolation. The three auxiliary feedwater pumps are interconnected but must be manually aligned. Duke Power Company has indicated that it would add two electrically driven pumps to each unit within a period of 3 to 4 months.

Crystal River

This plant has two centrifugal pumps, one motor-driven and safety grade and the other steam turbine-driven, with suction from these sources not designed to seismic Category I (not qualified sources during a seismic event). Auto start occurs on loss of both main feedwater pumps as detected by low control oil pressure and will start turbine-driven pump if the motor-driven AFW pump is not running. The equipment for this auto start signal does not meet single failure criteria. In failure mode on loss of air, valves fail as is (air accumulators at valves are good for three cycles). Steam line failure matrix isolates all feedwater to steam generator. (Auxiliary feedwater is also isolated; the operator must establish feedwater flow.)

Rancho Seco

This plant has two centrifugal pumps, one motor-driven Class 1E and one motor and turbine tandem (motor Class 1E), with suction from three sources, with only one seismic Category I. Auto start occurs on loss of both feedwater pumps below 850 psig or loss of all reactor coolant pumps (RCPs) as detected by power monitor (voltage, current, and phase). These auto start signals are safety grade and meet single failure criteria. Turbine-drive pump starts on SFAS signal. In failure mode on loss of air, feedwater control valve (FCV) fails open. In failure mode on loss of power, FCV fails to 50% position. There is a Class 1E MOV bypass around the FCV on safety features actuation signal (SFAS). Steam line failure matrix does not isolate auxiliary feedwater (feedwater is available to the steam generator at all times).

Davis-Besse 1

This plant has two steam driven centrifugal pumps, suction from three sources, one of which is designed to seismic Category I. Auto start signal is from safety grade steam and feedwater rupture control system.

Arkansas 1

This plant has two centrifugal pumps; one is motor-driven (not Class 1E) nonsafety grade and the other is steam turbine driven. Auto start signal occurs from loss of both feedwater pumps or low pressure from auxiliary pump or loss of all RCPs as sensed by the RCP breakers, the equivalent for these signals is not safety grade. In failure mode on loss of power, valves fail as is. Steam line failure does not isolate emergency feedwater to the steam generator.

2.2.5 Integrated Control Systems

The B&W integrated control system (ICS) is designed to provide the proper coordination of the reactor, steam generator, feedwater control, and turbine under normal operating conditions. The automatic reactor coolant pressure control and the automatic pressurizer level control are separate and are not integrated with the ICS. A short functional description of the ICS is presented as background for further discussion of the system.

The ICS includes four subsystems consisting of (a) the unit load demand control, (b) the integrated master control, (c) the steam generator control, and (d) the reactor control. The unit load control is designed to constrain the load demand signal to the maximum load capabilities and rate of load response capabilities of the plant. The unit load control also initiates runback functions to restrict operation of the plant within prescribed limits. For example, upon loss of one feedwater pump, there is an automatic power runback at 50 percent per minute to a power consistent with the capability of the remaining sump.

The integrated master control is designed to receive the megawatt demand signal from the unit load demand subsystem and to convert this into a demand signal for each of the feedwater control, turbine control, and reactor control subsystems. The reactor control, the feedwater control, and the turbine control are the major controls for the conversion of nuclear energy into electrical energy.

The reactor control subsystem is designed to maintain a constant average coolant temperature over the load range from 15 to 100 percent of rated power. From zero to 15 percent of rated power, this subsystem controls at a prescheduled average temperature as a function of power.

Feedwater demand for the steam generator is scheduled as a function of demand load from 15 to 100 percent of rated power. This feedwater demand is compensated for deviations from the set point of the steam header pressure. The pressure error increases the steam generator demand feedwater and reactor power demands if the pressure is low, and vice versa if the pressure is high.

For turbine control, the megawatt demand is compared with the electrical generator megawatt output, and the resulting megawatt error signal is used to change the steam pressure set point. The turbine valve then changes position to control steam pressure.

The staff has held discussions and telephone conferences with Babcock & Wilcox regarding the ICS. Babcock & Wilcox has stated that the ICS is a standard item in their design and that all current operating plants have the same ICS. However, some differences do exist in the implementation of the controls.

One difference among the various operating plants is the implementation of the steam generator feedwater control. For some plants, demanded feedwater flow is achieved by throttling the main feedwater valve. In other plants, variation in feedwater flow is achieved by directly varying feedwater pump speed. B&W has stated that there is no difference in the functional response of these controls to supply feedwater to the steam generator.

Another difference among the various operating plants is the interface between the ICS and the turbine controls. This difference was defined by B&W to be minor in nature and to involve the signal format rather than functional differences in the design.

Based on this preliminary information, it is reasonable to expect that, for all operating plants of the B&W design, similar control systems will respond in like manner to the same transient or event. Additional study will be required to substantiate this preliminary assessment. It is recommended that the study be conducted because it will serve to provide a more comprehensive understanding of the control systems, especially with regard to its interactions with the OTSG, the pressurizer, and the auxiliary feedwater.

In addition to the ICS, there are other plant control systems and monitoring systems that could be important to safe operation. Traditionally, the plant control and monitoring systems are not designed to Class 1E standards as the safety systems. These systems are generally designed to assure a high availability of plant operation. However, multiple failures in the control systems or single failures of a control system combined with an operator error could result in violation of safety limits. Although the staff currently reviews control system failures for impact on the safe operation of the plant, the review is not performed in the same scope and depth as the review of safety systems.

The adequacy of monitored plant data and its availability to the operator during transients and periods of degraded operation is another area that requires staff reassessment. Inadequate facility status data may result in operator actions or inactions that aggravate rather than mitigate the transients. This may result in safety challenges beyond the scope of the design basis of the safety system.

As noted in the preceding, the plant control and monitoring systems have not been designed and reviewed to the same standards as plant safety systems nor should they be. Nevertheless, the TMI-2 event has highlighted the importance of these systems and the need for the development of appropriate standards to ensure that these systems are designed, installed, and tested in a way that is consistent with safe plant operation.

2.2.6 Safety Systems

This section discusses the safety and protection systems of the nine licensed B&W reactors. Similarities and differences are described and a general description of function and operation is included.

Reactor Trip Systems

The reactor trip systems of all operating B&W plants are essentially identical, because this portion of the design is almost totally within the scope of supply of B&W. The reactor trip system is designed to protect the fuel and reactor coolant system pressure boundary for all anticipated operational transients. As such, the system is required to meet stringent design, installation, and operational requirements of a nuclear safety grade system that includes single failure criterion, equipment qualification and testing, and quality assurance (as specified in 10 CFR Part 50 and associated industry standards such as IEEE-279).

The reactor trip system includes four redundant and independent channels. Each channel has its own independent input sensors that are physically separated from the sensors of the other protection channels and that monitor the following trip conditions:

1. Nuclear power/flux (high)
2. Nuclear power based on flow (high)
3. Nuclear power based on reactor coolant pump status (high)*
4. Reactor coolant system pressure (high)
5. Reactor coolant system pressure (low)
6. Reactor coolant system pressure based on temperature (low)
7. Reactor coolant temperature (high)
8. Reactor building (containment) pressure (high)

*The trip system in Crystal River 3 does not monitor for this condition.

Each channel contains eight trip bistables (one associated with each of the above conditions). Each input sensor causes a bistable trip, which in turn actuates a trip relay within a reactor trip module.

The reactor trip module combines the four-channel bistable trip signals in a two-out-of-four coincident logic to trip the control rod power supply breakers. Trip of the breakers removes the power supply to the rod drive mechanisms and the control rods enter the core. Table 5 provides a typical listing of reactor protection system trip set points.

2.2.7 Engineered Safety Features Actuation System (ESFAS)

The ESFAS of all operating B&W plants are functionally similar. The systems sense an off-normal change in a plant condition and actuate safety systems to mitigate or minimize core damage and to minimize radioactive releases. The implementation of these functions vary because many are designed and implemented within the balance-of-plant scope. The ESFAS is also required to be designed to the same stringent standards as for the reactor trip system.

The typical ESFAS is comprised of three or four redundant and independent channels. (Only Davis-Besse 1 has four.) Each channel has its own independent input sensors that are physically separated from the sensors of the other protective channels and each channel typically monitors the following plant conditions:

1. Reactor coolant pressure (low)
2. Reactor building/containment pressure (high)

In the Davis-Besse 1 design, containment vessel radiation level and borated water storage tank level are monitored; however, these are for limited special functions. An indication of high containment radiation level isolates the containment purge system, whereas a low borated water storage tank level initiates switchover from safety injection to recirculation. In addition, in Davis-Besse Unit 1, certain other conditions are monitored by the steam and feedwater rupture control system (see above) which is part of the ESFAS.

In certain other plants (Arkansas Unit One and Crystal River 3, for example), instrumentation to detect a steam line break is provided as part of the plant ESFAS.

The typical actions to be accomplished by the ESFAS include:

1. High-pressure coolant injection
2. Low-pressure coolant injection
3. Reactor building/containment isolation
4. Reactor building/containment cooling
5. Reactor building spray
6. Emergency feedwater (Rancho Seco and Davis-Besse 1 only)
   [Note: At Rancho Seco, the turbine-driven emergency feedwater pump is actuated by low reactor coolant pressure or high containment pressure. At Davis-Besse 1,

TABLE 5 TYPICAL REACTOR PROTECTION SYSTEM TRIP SETTING LIMITS

Reactor Protection System Trip Set Points	Four Reactor Coolant Pumps Operating (Nominal Operating Power - 100%)	Three Reactor Coolant Pumps Operation (Nominal Operating Power - 75%)	Operating in Each Loop (Nominal Operating Power - 49%)
1. Nuclear power, max. % of rated power	~105.5	~105.5	~105.5
2. Nuclear power based flow[1] and imbalance, max. % of rated power	1.07 times flow minus reduction due to imbalance(s)	1.07 times flow minus reduction due to imbalances	1.07 times flow minus reduction due to imbalances
3. Nuclear power based on pump monitors,[3] max. % of rated power	NA (see note[2])	NA (see note[2])	77%[3]
4. High reactor coolant system pressure, psig, max. (see note 4)	~2355	~2355	~2355
5. Low reactor coolant system pressure, psig, man.	~1900	~1900	~1900
6. Variable low reactor coolant system pressure, psig, min. (see note 5)	$\sim(16.25T_{out}-7834)$	$(16.25T_{out}-7834)$	$(16.25T_{out}-7834)$
7. Reactor coolant temp., °F, max.	~619	~619	~619
8. High reactor building pressure, psig, max.	~4	~4	~4

[1]Reactor coolant system flow, %
[2]The pump monitors also produce a trip on (a) loss of two reactor coolant pumps in one reactor coolant loop, and (b) loss of one or two reactor coolant pumps during two-pump operation.
[3]Pump monitors indicate the loss of a reactor coolant pump when the measured power to the pump is equal to or less than 25% of the running power.
[4]To be revised per IE Bulletin 79-05B
[5]T_{out} is in degrees Fahrenheit (F)

the emergency feedwater and steam generator isolation is initiated by an ESFAS type of system (steam and feedwater rupture control system SFRCS) designed to detect a steam or feedwater line rupture, loss of feedwater event, or loss of all reactor coolant pumps.]

7. Steam generator isolation
8. Auxiliary support for all of the above (onsite power system, component cooling water system, ultimate heat sink, etc.).

The independent and redundant input channels (three or four, depending on the plant) are typically coupled to two independent and redundant logic channels. Based on the coincidence of two-out-of-three or two-out-of-four input channels, the logic channels actuate the corresponding independent and redundant component trains consisting of pumps, valves, and/or motors (for example, ECCS).

The significant functional difference between the ESFAS designs for the operating plants is the signal or combination of signals needed to actuate a component train to accomplish a particular action.

All of the B&W plants perform the actions indicated on Table 6. In addition, Rancho Seco and Davis-Besse 1 have ESFAS signals initiating reactor building cooling and isolation on low reactor coolant pressure or high reactor building pressure.

2.2.8 Power-Operated Relief Valves

The failure of the power-operated relief valve (PORV) to reclose following the overpressure transient was a key factor during the TMI-2 event. This section discusses this component and previous operating experiences related thereto.

The reactor coolant system is required by the ASME Boiler and Pressure Vessel Code to be protected from transient overpressure conditions. This protection is accomplished by several means, including reactor trip, operation of code required safety valves, or operation of relief valves.

Figure 7 shows the typical arrangement of relief and safety valves on the pressurizer. The two code safety valves are each rated to be one-half the required relieving capacity.

The power-operated relief valve is a pilot-operated valve and does not replace a code required safety valve or contribute to the required relieving capacity for the reactor system. The purpose of this valve is to limit the lifting frequency of the code safety valves by relieving at a lower set point. This enhances plant availability. In addition, this valve is used to prevent overpressurization of the reactor system during operation at low temperatures, an operational mode when NDTT (nil ductility transition temperature) becomes a consideration for component structural integrity.

TABLE 6 SAFETY FEATURES ACTUATION CONDITIONS

Action	Trip Condition	Trip Set Point, psig*
Start emergency core injection: a) High press. b) Low press.	Low reactor coolant pressure or High reactor building pressure	1500-1600 ~4
Start reactor building cooling, reactor building isolation, and open reactor building spray valves	High reactor building pressure	~4
Start reactor building spray pumps	High reactor building pressure	~10-30

*The set points may vary plant to plant.

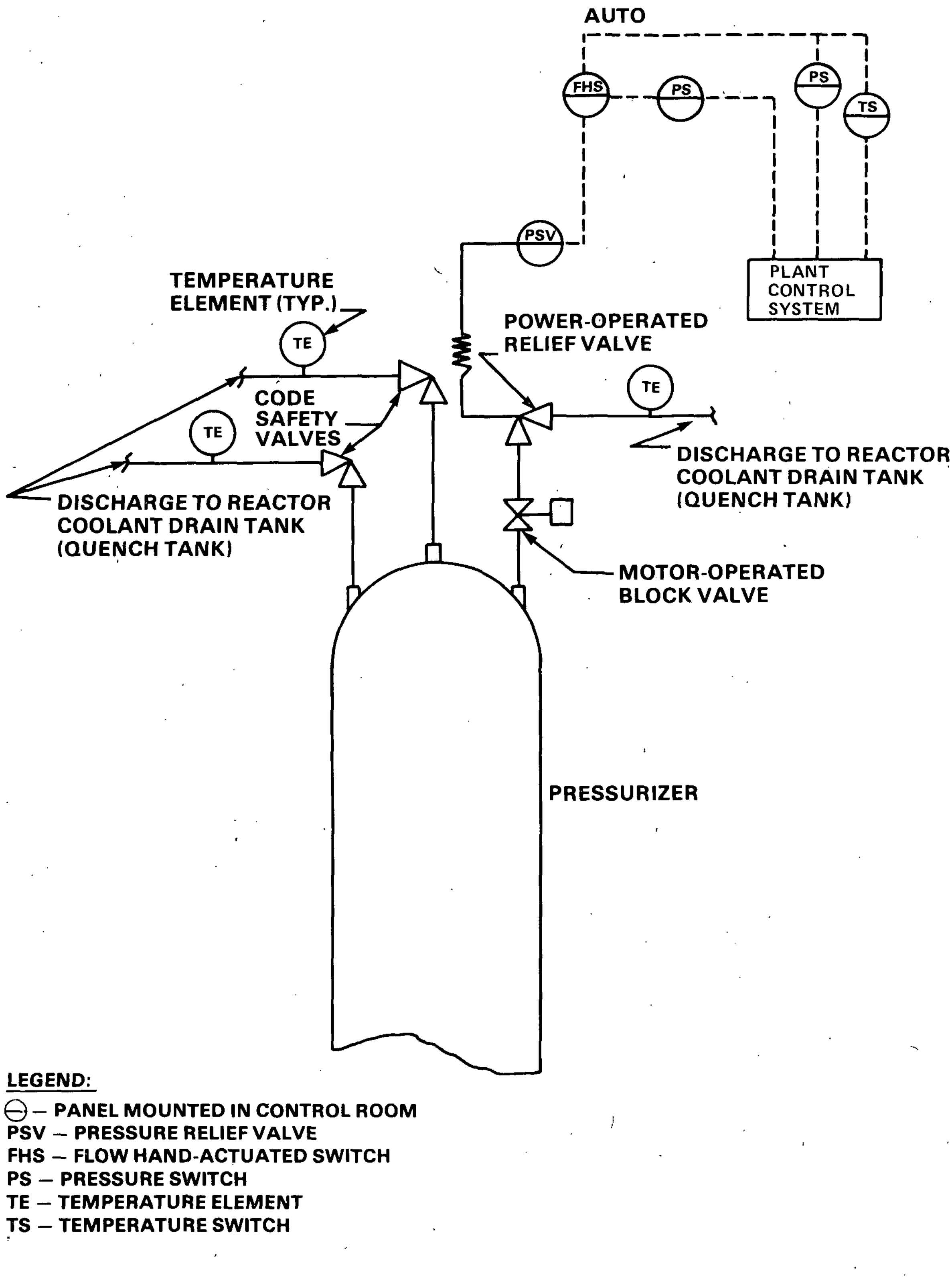


Figure 7. Typical Arrangement of Relief and Safety Valves on Pressurizer (B&W).

The valve can be operated either manually or automatically by a mode selection switch located on a panel in the control room. Manual operation can be accomplished from the control room regardless of the reactor system temperature or pressure. Automatic operation of the valve can be selected in which case the valve opens at a preselected pressure sensed in the reactor coolant system and remains open until the pressure decays to the reseat pressure of the valve. This is the mode the valve is in during normal operation. Set and reseat pressure for the Babcock & Wilcox designed plants along with other valve data are in Table 7. The NDTT protection mode can also be selected in which case the valve will open in the event of a preselected low-pressure set point is reached or reactor temperatures are above the NDTT limit.

Failures of the PORVs in the reactor coolant systems are indicated by their dates of occurrence in Table 7. In the severest case, the valve remained open and caused rapid depressurization of the reactor coolant system. In the case of Oconee 3, the malfunction of the valve was caused by boron crystal buildup on the valve lever, heat expansion, rubbing of the lever against the solenoid brackets and bending of the solenoids spring brackets. The open-closed indicating lights in the control room gave no indication that the valve was open during the transient. The failure at Three Mile Island 2, on March 29, 1978, was caused by de-energization of a vital bus that consequently energized the PORV valve solenoid and thus opened the relief valve until power was restored to the bus. A design change was incorporated to eliminate the valve operation upon the event of loss of power to the vital bus. The valve malfunction at Davis-Besse 1 was caused in part by foreign material binding the stem in the guide area of the pilot valve nozzle; however, a seal-in relay was missing from the system.

The control circuits for the valve are currently not single failure proof. That is, a single failure in the control circuits can result in a small break LOCA. Current operating history is unfavorable and indicates a possibility of such a LOCA in the order of 0.1 per reactor year of operation.

Currently, a block valve is provided upstream of the relief valve to isolate such failures; however, it requires the operator to monitor other system parameters to detect valve failure. These parameters include temperature detection on the discharge pipe, position indication of the PORV and quench tank level and pressure. The response of the temperature detector does not always indicate valve failure promptly because of the time lag in cooling-off after PORV closure. Position indication is not direct since it only indicates whether the solenoid is energized and does not account for mechanical failures. Quench tank level and temperature is the best indication but it is slow and apparently not effective as demonstrated at TMI-2.

TABLE 7 CODE SAFETY-RELIEF VALVES AND POWER-OPERATED RELIEF VALVES ON PRESSURIZER FOR B&W PLANTS

Valves for B&W Plants	Arkansas 1	Crystal River 3	Davis-Besse 1	Oconee 1	Oconee 2	Oconee 3	Rancho Seco	Three Mile Island 1	Three Mile Island 2
<u>Code Safety-Relief Valves</u>									
Mfg	Dresser	Dresser	Crosby	Dresser	Same	Dresser	Dresser	Dresser	Same
Number	2		2	2		2	2	2	
Type	Spring-loaded	Spring-loaded	Spring-loaded	Spring-loaded		Spring-loaded	same	Spring-loaded	
Model no.	3-31759A	2½ - 31739A	3XM1X6, Type HB86-	2½ -31739A		2½-31739A		2½-31739A	
Size	3" x 6"	2½" x 6"	4" x 6"	2½" x 6"		2½" x 6"		2½" x 6"	
Relief cap.	311,733 #/hr	311,733 #hr		311,973 #/hr		317,973 #/hr		280,000 #/hr	
Set press.	2500 psig	2500 psig		2500 psig		2500 psig		2500 psig	
Reseat press. (approx.)	2375	2375		2375		2375		2450	2475
Known malf. (significant)	None	None	None	None		None		None	None
<u>Power-Operated Relief Valves</u>									
Mfg	Dresser	Dresser	Crosby	Dresser	Same	Dresser	Dresser	Dresser	Same
Number	1	1	1	1		1	1	1	
Type	Electromatic	Electromatic	Electromatic	Electromatic		Electromatic		Electromatic	
Model no.	31533VX-30	Same	HPV-ST	31533 VX-30		31533VX-30		31533VX-30	
Size	2½" x 4"		2½" x 4"	2½" x 4"		2½" x 4"		2½" x 4"	
Relief cap.	106,450 #/hr	100,000 #/hr	112,000 #/hr	100,000 #/hr		100,000 #/hr	112,000 #/hr	106,450 #/hr	
Set press.*	2300 psig		2235 psig	2300 psig		2300 psig		2300 psig	
Reseat press.						2220 psig		2250 psig	
Malf. date (significant)	9/1/74	None	9/24/77	None	None	June 1975	June 1978	None	3/29/78
cause	Improper venting		Steam pilot valve system			Boric acid crystal buildup, bent lever on pilot valve	Valve leakage		De-energized vital bus

*To be revised per I&E Bulletin 79-05B

TABLE 7 CODE SAFETY-RELIEF VALVES AND POWER-OPERATED RELIEF VALVES ON PRESSURIZER FOR B&W PLANTS (Continued)

Valves for B&W Plants	Arkansas 1	Crystal River 3	Davis-Besse 1	Oconee 1	Oconee 2	Oconee 3	Rancho Seco	Three Mile Island 1	Three Mile Island 2
PORV (Cont.)									
Fail position	Closed (Class 1E)	Closed (1E)	Closed (non-1E)	Closed (non-1E)			Closed (non-1E)	-	
Position Ind.	Yes (Pilot-red/green)	Yes (open-closed)	Yes (on pilot-red/green lights)	Yes (open-closed)			No	Pilot-red green	
Thermocouple ind. and alarm	Yes (computer)	Yes (computer)	Yes (computer)	Yes (computer)			Yes (computer)	Yes	
Thermocouple type and location	Strap-on	Well/~90 ft from valve	Strap-on/ ~1 ft	Strap-on/6 7 ft downstream			Strap-on/40 ft from valve		
Block Valve									
Mfg.	Velan	Dresser	Velan	Westinghouse	Same	Same	Velan		
Type	Motor-operated	Motor-operated	Motor-operated	Motor-operated			Motor-operated	Motor-operated	Same
Fail position	As-is (non-1E)	As-is (1E)	As-is (non-1E)	As-is (non-1E)			As-is (non-1E)	-	
Pos. indication	Yes	Yes	Yes	Yes			Yes	Yes	

Consideration should be given to the merits of upgrading the PORV and associated controls and power equipment to safety grade, or, as an alternate, consideration should be given to closing the PORV and block valve during power operation.

2.2.9 Pressurizer Level Indication

During the reviews of the recent events at TMI-2, the accuracy and significance of the pressurizer water level indication was questioned. This section describes the instrumentation and provides an assessment of the potential for false indications during the event. The interpretation in terms of primary system inventory is addressed and discussed.

The general layout of a typical pressurizer level instrumentation system is given in Figure 8. Three systems are installed. For each system, two impulse lines connect to the pressurizer; one near the top and one near the bottom. The lines are routed to a differential-pressure transmitter, located near the bottom of contaiment in the annular region between the shield wall and the containment wall. Level indication generally follows the changes in system pressure and fluid inventory for normal operating situations.

There are a number of factors that could affect the accuracy of the level instrumentation. If the liquid density changes due to a temperature change, the calibration could vary. At TMI-2, this is corrected automatically and continuously by a temperature instrument applying a correction in the level readout instrument.

There are several other factors that were earlier thought to affect instrument accuracy in a depressurization event as follows:

1. A rapid reduction in pressurizer pressure could cause liquid to flash in the reference leg (the line connecting the transmitter to the pressurizer near the top of the vessel, see Figure 8.) Such flashing, should it be significant, could cause the instrument to indicate a falsely high pressurizer water level.

2. Degassing of liquid in the reference leg could also cause an error. Dissolved gases could rapidly be driven out of the reference leg by this mechanism, and the level instrument would again indicate a falsely high level.

3. Should the pressurizer depressurization occur rapidly, a venturi effect could in principle be created at the point where the reference leg joins the pressurizer vessel. If this occurred, liquid could be drawn out of the reference leg causing the same inaccuracies in level indication noted above.

The importance of each of these effects has been assessed assuming conditions that existed at TMI-2 prior to and during the event. Calculations were performed to estimate the effects of both flashing and degassing. Even though the calculations indicated that some flashing could occur, the reduction in water level in the

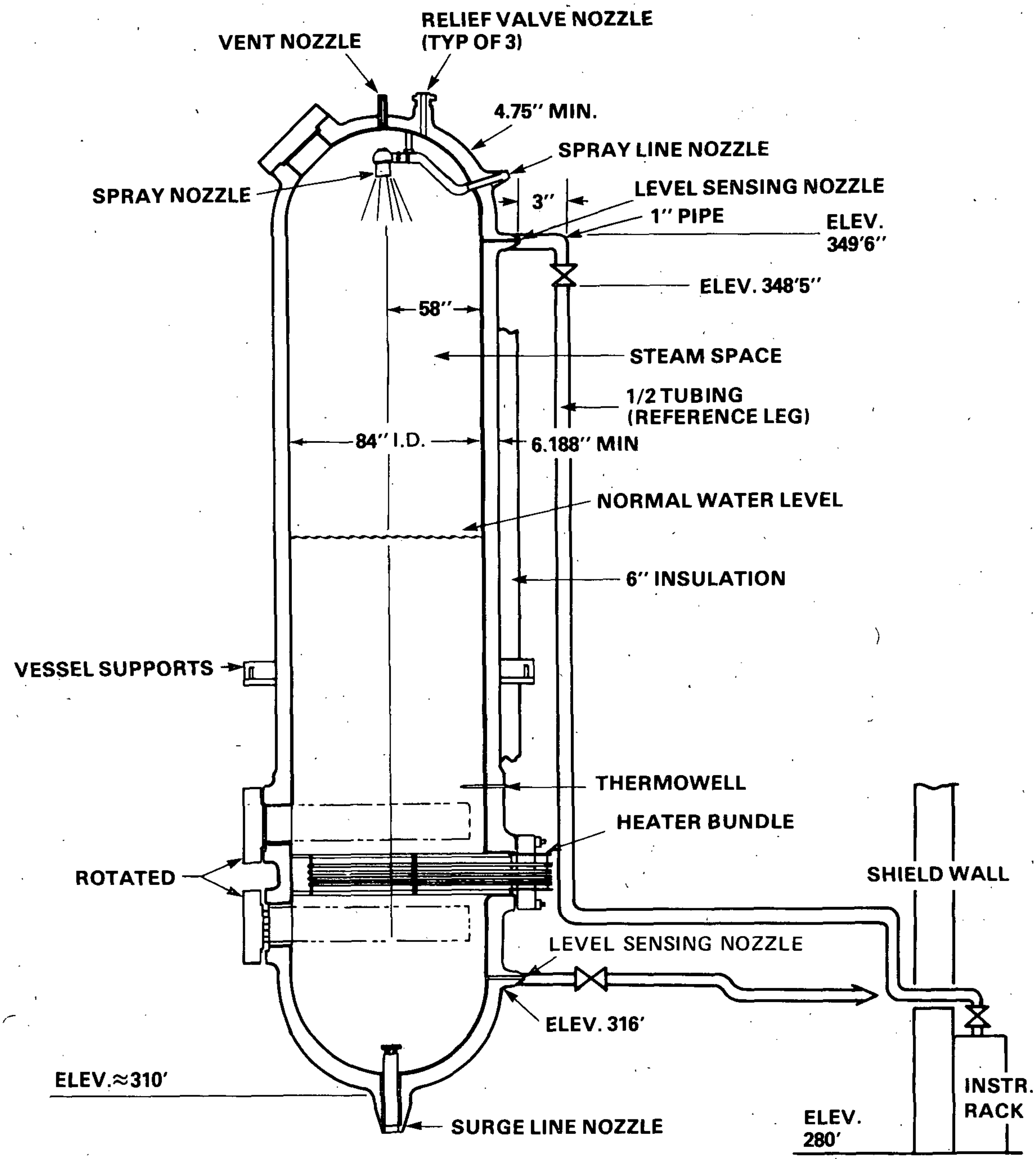


Figure 8. TMI-2 Pressurizer Level Instrument System (typical of all B&W plants).

reference leg due to flashing is estimated to be less than 1 foot. Because the distance between the taps is about 33 feet, the effect of this reduction would be small. Calculations also indicate that the effect of degassing of liquid in the reference leg is negligible. With regard to the venturi effect, it is estimated that gas velocities at the upper level sensing nozzle are too low to produce any significant effect.

We conclude from these assessments that the errors in level instrument indications during the event at TMI-2 were not large. In particular, potential effects including the surge line configuration that could cause falsely high indicated levels were assessed not to be significant. Therefore, the increasing level indicated by the instrumentation beginning about 1 minute into the event at TMI-2 is believed to have resulted from an increasing level of water in the pressurizer.

Interpretation of Indication

It cannot be assumed that the presence of water in the pressurizer is indicative of an adequate water level in the reactor vessel. The B&W design includes no instrumentation that provides a direct indication of primary coolant inventory. Because the TMI-2 event has suggested the need for an instrumentation system that directly provides coolant inventory data, the B&W design should be reassessed to ensure that it conforms to GDC-13. This would also apply to the other reactor vendors.

Even though there is no direct indication of coolant inventory available to the operator, an assessment of the data taken during the TMI-2 event shows that there were instrument readings that showed indications of cooling problems early in that event. The pressurizer level sensing system indicated a rapidly increasing level after about 1 minute into the event. At about 6 minutes into the event, the level indication signified that the pressurizer was full. However, the reactor coolant system pressure was still quite low at this time, 1300 to 1500 psi, indicating that part of the coolant system was boiling and therefore could not be assumed to be solid. The level increase in the pressurizer between 1 and 6 minutes into the event could have been caused by expansion of the coolant in the primary system due to the lack of feedwater in the steam generators and by the generation of steam in the core resulting from the initiation of boiling. With steam in the core, liquid would be displaced from the primary coolant system and forced into the pressurizer.

Discussion

Assurance that an adequate water level exists in the reactor vessel requires monitoring of parameters other than pressurizer water level (e.g., coolant pressure, coolant temperature, etc.). The licensees and the staff should review the instrumentation and the plant operating procedures with the objective of establishing that (a) the operator has adequate information available, and (b) he is required to assess all pertinent information available to him (instrument readings), and (c) he is instructed to take appropriate corrective action based on that assessment.

On a longer term basis, more direct and more easily interpreted indicators of water inventory in the primary system would make operator inference and actions more reliable. Specifically, one approach can be characterized as instrumentation to measure and directly display to the operator such derived quantities as the subcooling in the reactor outlet, or the quantity of and energy content of cooling water in the core. Also, an assessment of the balance between additional automation versus improved operator response to maintain adequate plant conditions should be made.

2.2.10 Containment Isolation System Design Features

The design objective of the containment isolation system is to allow the normal or emergency passage of fluid through the containment boundary while preserving the ability of the boundary to prevent or limit the releases of fission products that may escape from the reactor core in the event of an accident. Therefore, following an accident, it is necessary that the containment be isolated yet permit operation of these systems necessary to mitigate the accident consequences to accomplish their safety functions.

The containment isolation system of a nuclear power plant is designed to automatically isolate the non-essential systems penetrating the containment. The isolation of essential systems such as the engineered safety features, if the need arises, is accomplished by the remote manual manipulation of the system isolation valves by operators in the control room.

It has been reported that during the recent incident at the Three Mile Island Nuclear Plant, Unit 2 (TMI-2), the containment was not immediately isolated, and contaminated water was pumped out of the containment by the automatic initiation of a sump pump. Contaminated water was transferred to the liquid radioactive waste treatment system in the auxiliary building where some water spilled to the floor. Outgassing from this water and the subsequent discharge of the radioactive gases through the auxiliary building ventilation system was the principal source of the offsite release of radioactive noble gases. This situation occurred because containment isolation actuation at TMI-2 only occurs upon receipt of a high containment pressure (4 psig) signal. For the TMI-2 incident, fission products were released to the containment without an accompanying rise in the containment pressure to the high-pressure set point for containment isolation.

For reasons not known at this time, the reactor pressure was never low enough (about 300 psig) to to into the low-pressure heat removal system (RHR) located outside of the containment. This matter should be evaluated and the RHR design basis reassessed.

A study of the containment isolation actuation systems at other operating plants having a Babcock & Wilcox (B&W) nuclear steam supply system was undertaken to determine the extent of the TMI-2 practice for only isolating the containment on receipt of a containment high pressure signal. The eight operating B&W plants are listed in Table 8 along with the parameters sensed for containment isolation actuation. The parameters sensed include containment pressure (high), reactor coolant pressure (low), and containment radiation level (high). It is apparent from the table that the containment isolation actuation system designs are basically the same. Only two plants, Rancho Seco 1 and Davis-Besse 1, use another parameter for containment isolation, namely, reactor coolant low pressure. Furthermore, Davis-Besse 1 includes a containment high radiation signal to isolate lines that, when open, provide a direct connection to the environs outside containment. For the plants that include more than one parameter in the containment isolation actuation signal, a coincidence of signals is not required to initiate containment isolation; i.e., each parameter, upon reaching its set point, can initiate containment isolation.

The containment isolation actuation system designs for these plants also indicate differences in the isolation provisions for essential lines; i.e., lines that do not have a post-accident safety function yet are important to plant safety. These lines typically provide cooling and seal injection water to the control rod drives and reactor coolant pumps.

Table 9 shows how the isolation of these lines is typically treated for three of the plants; namely, Three Mile Island 2, Rancho Seco 1, and Davis-Besse 1. The TMI-2 Safety Analysis Report states that the reactor coolant pumps must be secured immediately upon loss of both seal water injection and cooling water. Although all three plants show the reactor coolant pump seal water injection lines to be automatically isolated, Rancho Seco 1 and Davis-Besse 1 provide for the continuation of cooling water to the reactor coolant pumps. This is done to protect the reactor coolant pump seals in the event of spurious isolation signals or to keep the pumps operating for as long as possible in the event of an accident. Since there is no uniform approach to the identification or treatment of essential lines, it appears appropriate to reevaluate the requirements of isolating essential lines in nuclear power plant safety, and develop guidelines to assure consistency in identifying these lines and establishing containment isolation actuation provisions for them.

The normal operating modes and containment isolation provisions for the reactor building sump (RBS) and reactor coolant drain tank (RCDT) discharge lines were also reviewed at to determine how operating plants handle the transfer of potentially radioactive fluids out of the containment.

For TMI-2, there is an automatic mode for the RBS discharge line, and fluid transfer will occur if the sump level reaches a prescribed set point. Provisions for automatic isolation of the discharge line was believed to be adequate because

TABLE 8 PARAMETERS SENSED FOR CONTAINMENT ISOLATION ACTUATION AT OPERATING PLANTS HAVING BABCOCK & WILCOX NUCLEAR STEAM SUPPLY SYSTEMS

Plant (A/E)	Date of Commercial Operation	Parameters Sensed CHP*	CHR*	RCLP*	
Oconee 1, 2, 3 (Bechtel/Duke)	1973-74	X			
Arkansas 1 (Bechtel)	1974	X			
TMI-1 (Gilbert Assoc.)	1974	X			
Rancho Seco 1 (Bechtel)	1975	X		X	'OR' logic
Crystal River 3 (Gilbert Assoc.)	1977	X			
Davis-Besse 1 (Bechtel)	1977	X	X**	X	'OR' logic
TMI-2 (Burns & Roe)	1978	X			

*CHP = containment high pressure
CHR = containment high radiation
RCLP = reactor coolant low pressure

**Containment purge system and containment air sample lines only

TABLE 9 CONTAINMENT ISOLATION ACTUATION OF ESSENTIAL LINES

Line Service	TMI-2	Rancho Seco 1	Davis-Besse 1
	Plant Name		
Cooling water to RCP oil and motor coolers	Automatic isolation on HI containment pressure	Remote manual isolation	Automatic isolation on HI-HI containment pressure
RCP seal water injection	Automatic isolation on HI containment pressure	Automatic isolation on receipt of safety injection signal	Automatic isolation on receipt of safety injection signal
Cooling water to CRD coolers	Automatic isolation on HI containment pressure	Remote manual isolation	Automatic isolation on HI-HI containment pressure

a release of coolant from the reactor would cause a pressure increase in the containment; however, the coolant released was not sufficient to pressurize the containment to the set point in TMI-2 during the first few hours of the accident.

The system isolation valves close upon receipt of a containment high-pressure signal (4 psig). For subsequent fluid transfer to occur, the engineered safety features actuation signal must be reset manually in the control room and the isolation valves must be reopened by operator action, even if the transfer pump is in an automatic operating mode. These is no such automatic operating mode for the RCDT discharge line.

Operator action is required to initiate fluid transfer during normal plant operation, and would also be required following an accident after the operator resets the engineered safety features actuation signal.

For the Arkansas 1 and Oconee 1, 2, and 3 plants, the reactor building sump and reactor coolant drain tank discharge lines are normally closed and require operator action for the transfer of fluids out of the containment.

Licensing Requirements

It now appears that review and possibly some upgrading of the containment isolation actuation system designs of the operating plants is warranted. Standard Review Plan 6.2.4, Containment Isolation System, added a requirement, compared to previous practice, for diversity in the parameters sensed for the initiation of containment isolation. At the time the Standard Review Plan was developed, it was felt that the lack of diverse parameters for actuation of the isolation system did not represent a safety problem warranting a backfit to previously licensed plants.

Other Operating Pressurized Water Reactor Plants

The containment isolation actuation systems of several operating nuclear power plants using the Combustion Engineering (C-E) and Westinghouse (W) nuclear steam supply systems were also reviewed to determine the extent of diversity in the parameters sensed for automatically initiating containment isolation.

The Palisades Nuclear Power Station, which began commercial operations in 1971 (the first CE plant to do so), and the St. Lucie Plant, Unit 1, which began commercial operation in 1976, were the C-E plants selected for review. It was felt these plants would reveal any design changes in the engineered safety features actuation systems that may have occurred during the period from 1971 to 1976. However, there were no changes. For both plants, either containment high pressure or containment high radiation will initiate containment isolation and automatically isolate nonessential lines penetrating the containment. Although diverse parameters are sensed for the initiation of containment isolation, the safety injection signal (which initiates emergency core cooling) is not used to initiate containment isolation.

The Westinghouse plants that were examined included the Turkey Point Station, Unit 3, which began commercial operation in 1972; the Zion Nuclear Plant, Unit 2, which began commercial operation in 1974; the Indian Point Station, Unit 3, which began commercial operation in 1976; and the D. C. Cook Plant, Unit 2, which began commercial operation in 1978. For all these plants, the safety injection signal is used to initiate the automatic isolation of all nonessential lines in the event of an accident. The parameters sensed to generate this signal include reactor coolant low pressure coincident with pressurizer low level, or containment high pressure, or steam line differential pressure, or steam line high flow coincident with reactor coolant low temperature or steam line low pressure. (It should be noted that the acceptability of relying on reactor coolant low pressure coincident with pressurizer low level to generate a safety injection signal is now under review as a result of the TMI-2 incident.)

2.3 Plant Response to Loss of Feedwater Events (LOFW)

2.3.1 Steady State Operation

The PWR reactor coolant system (RCS) behavior during steady-state operation principally involves a balance of coolant flow and heat transfer mechanisms to maintain equilibrium. The heat output of the core is essentially balanced by the heat removed by the steam generators. The reactor coolant liquid volume (inventory) is maintained relatively constant by a small (compared to total system volume) letdown/makeup flow rate. Thus, core heat production and heat removal via the steam generators are essentially equal, maintaining the reactor in thermal equilibrium, i.e., reactor coolant pressure, temperature and pressurizer water level (which reflects the average temperature in the reactor coolant system) remain essentially constant. (See Figure 9.)

2.3.2 Loss of Feedwater Event (General)

In order to maintain the reactor coolant pressure and temperatures within acceptable limits during a loss of normal heat sink (e.g., loss of feedwater transient), systems are incorporated to limit the rate of core heat energy deposited in the system (reactor protection system) and to provide for alternate paths for energy removal (power-operated relief valves, code safety valves and emergency feedwater). Both energy and mass are removed through the valves while the feedwater supply provides only energy removal. Since the emergency valves remove coolant, a makeup system (high pressure injection system) is provided to restore coolant lost through the valves. In addition, the HPI water accommodates shrinkage of RCS volume during the cooldown phase.

2.3.3 Interactions During Complete Loss of Feedwater Event

The behavior of the RCS during a loss of feedwater event may be divided into two phases. It is important to distinguish between these two phases since the first

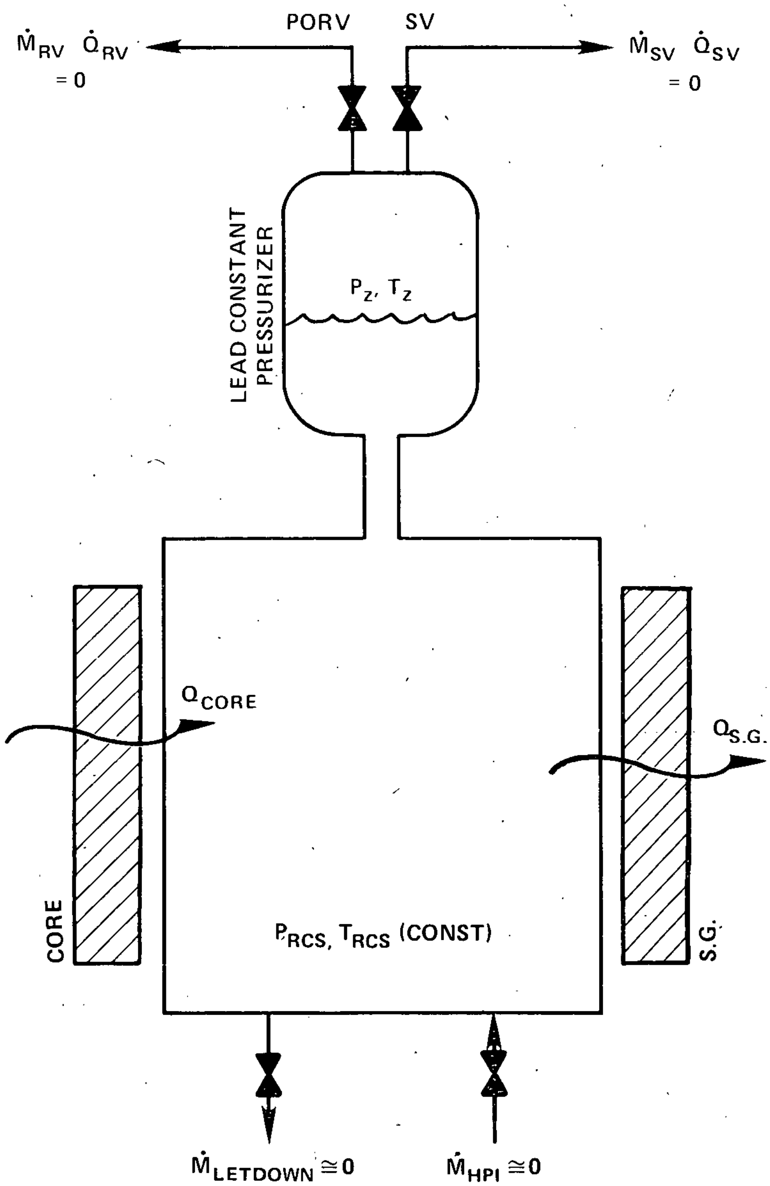


Figure 9. Initial Steady State: Core Heat Generated = Steam Generated (S.G.) Heat Removed → Temperature, Pressure Constant.

phase is handled in a predominately automatic manner, while the latter phase involves automatic systems, inherent plant characteristics and operator actions.

In the first phase, which occurs during the early (15 seconds) part of the transient, more energy is being deposited in the system than is being removed (see Figure 10). That is, the core continues to put energy into the system at a constant rate during this phase while the steam generator energy removal capability diminishes. This growing imbalance results in an increase in energy stored in the RCS. This increases both pressure and temperature of the reactor coolant. The rising temperature of the primary coolant in turn results in its thermal expansion observed as a level swell in the pressurizer. This rapid energy increase in the RCS builds until the energy input of the core is sharply reduced (by reactor trip), and the relief and safety valves open and/or auxiliary feedwater system comes on. Thus, in essence, there is an initial period up to reactor trip where more energy is being added to the primary system than is being removed, immediately followed by a period in which more energy is removed from the primary system than is being generated (see Figure 11). The first phase is characterized by a pressure and temperature increase in the RCS resulting in a rapid pressurizer level swell. The second phase is characterized by a depressurization and cooldown of the RC water involving a rapid pressurizer level drop. Depending on the ability of the inherent/automatic aspects of the systems to handle the first phase and parts of the second phase of the event, greater or lesser burden is put on the reactor operator to handle the recovery-cooldown phase. The ability to ultimately safely recover from this event depends on (a) the inherent/automatic aspects of the systems to present the operator with a relatively controllable system still in a dynamic-state, and (b) the ability of the operator to correctly interpret and act upon conditions as they exist in the system.

2.4 Operational Aspects of Loss of Feedwater Transients

The following discussion covers various operational aspects of a loss of feedwater transient.

2.4.1 Loss of Feedwater (Normal Case)

Once the reactor trips on high RCS pressure, primary system pressure will rapidly drop because the combined system energy removal paths of the still open PORV and the still partially filled steam generator exceeds the energy put into the system by the reactor core. If the PORV recloses when its set point is reached, the continued depressurization or subsequent repressurization will depend on the availability of auxiliary feedwater. With auxiliary feedwater available, the rate of depressurization will depend on the imbalance between the stored and decay heat output of the core together with the steam generator heat removal capabilities dictated by the secondary-side steam generator water level and pressure. The B&W auxiliary feedwater capacity and steam generator level control is such that with the PORV reclosed the primary system will neither be overcooled (thereby draining

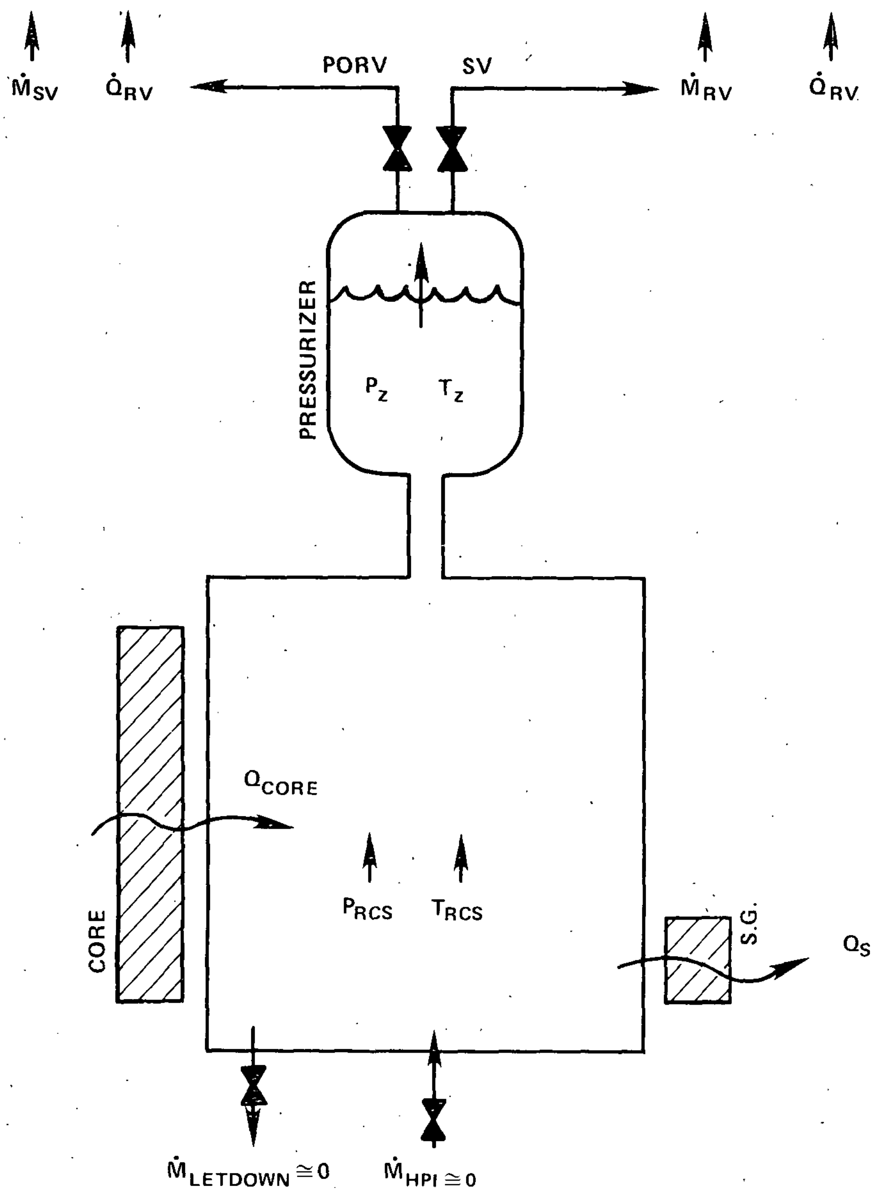


Figure 10. Transient Phase 1: Reactor at Full Power, S.G. Level Drops → Heatup and Pressurization (more heat generated than removed).

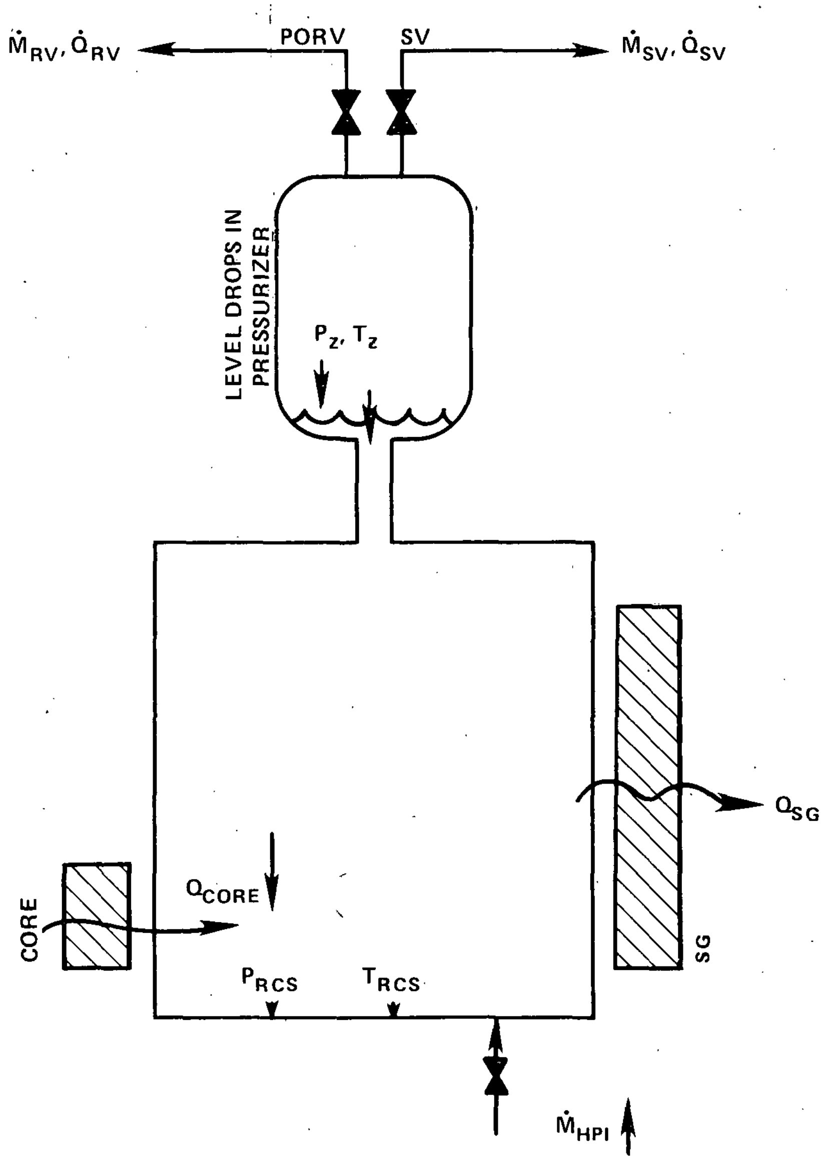


Figure 11. Transient Phase 2: Reactor Trips, S.G. Recovery Level → Cooldown and Depressurization (more heat removed than generated).

the pressurizer and inducing voids into the system) nor will it be undercooled (thereby allowing pressures and temperatures to increase sufficiently to relift the PORV). HPI will not come on because its set point would not be reached. Thus, the steam generator level setting will allow the transient decay heat energy to be removed while keeping the RCS adequately but not overly subcooled, thereby keeping system temperatures and pressures within acceptable bounds without high-pressure injection. There are no special actions required of the operator for this case. The reactor coolant system is automatically and adequately recovered and kept within an acceptable thermal-hydraulic condition (properly subcooled) by the auxiliary feedwater system without significant operator actions. The pressurizer pressure and level control systems automatically maintain primary system conditions.

2.4.2 Loss of Feedwater With No Emergency Feedwater

If the PORV closes and auxiliary feedwater is not available, the initial few seconds after the reactor trip will be similar to the preceding case. Reactor coolant system pressure and temperature will drop after the valve closes because, for a limited period of time, there will be more energy removed by the steam generators than is being put into the system by the stored and decay heat of the core. However, as the steam generators boil-off the secondary-side inventory, this imbalance will shift so that more heat is being added to the system than is being removed through the steam generators. Thus, pressure and temperature in the primary system would rise again to the set point of the PORV and/or the safety valves. Manual initiation of the HPI would be necessary.

If the operator is successful in establishing feedwater supply to the steam generators before the PORV can lift, HPI may not be necessary to make up for inventory lost through the PORV. If auxiliary feedwater supply cannot be established, then RCS pressure and temperature will rise until the PORV lift pressure is achieved. At this point, the reactor coolant inventory will begin to be lost from the primary system as the PORV lifts continuously or intermittently to release energy (and mass) from the primary system. Pressure will stay at the PORV set point without auxiliary feedwater. The operator must manually initiate HPI to promote subcooling and to make up for inventory lost through the relief valve. In summary, therefore, for the sequence necessary to promote subcooling, the operator should first try to reestablish feedwater supply, should then possibly trip two of the four reactor coolant pumps to reduce heat input and finally initiate HPI. If auxiliary feedwater is not established, subcooling in the primary system can be enhanced through the HPI pumps.

Small break analyses submitted for Oconee indicates that no core damage would occur in the first 20 minutes without emergency feedwater. The conditions are considered sufficiently similar to TMI-2 to provide a rough indication of time.

2.4.3 Loss of Feedwater with PORV Stuck Open

The combination of a PORV that is stuck open and auxiliary feedwater available represents the most severe case of depressurization. Energy is removed from the system via both the steam generators and the PORV. To terminate the excessive cooldown, depressurization and inventory loss, appropriate action would be to close to block valve to isolate the stuck-open PORV. If the open PORV is not isolated by the operator within the first few minutes, pressure will continue to drop until high-pressure injection is automatically initiated upon reaching the actuation pressure set point. High-pressure injection can more than make up for the inventory lost through the stuck-open PORV. Pressure and temperature will continue to fall approaching saturation conditions in the system before the primary system pressure slowly begins to rise. If saturation conditions are achieved, void formation in the system will cause the pressurizer level to swell.

With HPI left on continuously and auxiliary feedwater available, subcooling can be reestablished as pressures rise toward the safety valve set point and as temperatures fall due to the cooling effects of HPI and auxiliary feedwater. In summary, therefore, to promote subcooling the operator should first try to isolate the PORV and then possibly trip two of the four reactor coolant pumps. HPI will come on automatically and should be left on. HPI can be turned off only after adequate subcooling is achieved and the PORV is isolated.

2.4.4 Loss of Feedwater with PORV Stuck Open - No Auxiliary Feedwater

The combination of a stuck-open PORV and no auxiliary feedwater will cause the most severe case relative to achieving voiding and saturation conditions in the system. The rapid drop in RCS pressure and subsequent heatup of the primary system causes this most severe under subcooling scenario. The loss of feedwater event from high power at Three Mile Island on March 28, 1979, is an example of this case. The feedwater should be reestablished to the steam generators to enhance (sub)cooling of the primary system, since the inventory being lost through the PORV will be compensated automatically by automatic HPI actuation. Blocking the stuck-open PORV without auxiliary feedwater will result in a pressure and temperature increase to the pressurizer code safety valves. Inventory lost through the safety valves would have to be compensated for by manual operator initiation of HPI if the manually isolated PORV occurs soon enough to prevent RCS pressure from dropping to the initiation set point. If auxiliary feedwater is established with the PORV not isolated, this becomes the previously discussed case of a PORV that is stuck open with auxiliary feedwater available.

If the PORV is not isolated without auxiliary feedwater established, HPI will start automatically as system pressure will drop to the low-pressure actuation set point. The combination of a continued stuck-open PORV, no auxiliary feedwater, and HPI will not prevent saturation conditions from being reached and voids from forming in the system. Thus, the operator cannot prevent boiling in the core and the scenario becomes a small break loss-of-coolant accident with HPI making up for inventory loss. HPI must be left on by the operator to maintain inventory. In this regard, the operator would need to evaluate all pertinent plant parameters in determining the proper actions to be taken.

3.0 B&W PLANT OPERATIONS

3.1 Survey of Feedwater-Related Incidents

A review was made of reportable occurrences involving feedwater malfunctions at each of the operating B&W plants. An incident is reported in Licensee Event Reports (LERs) only if it violates plant technical specifications. Events that do not result in exceeding a technical specification limit are not considered to be reportable. Where relevant information is available on unreported incidents of significance to this study, it has been included. With regard to feedwater transients in general, a recent review by the staff of feedwater transients in PWR plants during the period from March 1978 through March 1979 shows the following results:

1. There were 9 B&W plants that had 27 feedwater transients or 3.00 per year, per plant;

2. There were 24 Westinghouse plants that had 44 feedwater transients or 1.83 per year, per plant; and,

3. There were 7 Combustion Engineering plants that had 13 feedwater transients or 1.85 per year, per plant.

The frequency of feedwater transients is not appreciably higher (about 60%) for B&W. The difference may be at least partially due to the initial operational life of the B&W plants as compared to Westinghouse and Combustion Engineering.

3.1.1 Crystal River

The following is a chronology of significant feedwater-related incidents at Crystal River Unit 3.

Date	Event Description	Significance
03/02/77	Loss of "B" AC inverter caused loss of "B" vital bus. Power was lost to ICS which caused reactor trip, turbine trip, and atmospheric steam dump. Main feedwater pumps tripped on loss of vacuum. (LER 77-20)	Moderate--Summarized below
03/07/77	Attempted startup of steam-driven emergency feed pump during testing. Pump tripped on overspeed. (LER 77-24)	Moderate--Summarized below

Date	Event Description	Significance
03/09/77	During startup testing, reactor was tripped manually from 40% power causing automatic turbine trip and transfer of station load to startup transformer. During transfer, momentary power loss caused zero speed indication on feedwater tachometer which tripped feed pump.	Moderate--Summarized below
04/16/77	During shutdown from hot standby condition outside control room, turbine-driven emergency feedwater pump (EFWP) tripped on overspeed during start using main steam. Pump manually started on auxiliary steam.	Moderate--Summarized below
06/02/77	During surveillance testing steam-driven EFWP experienced overspeed trip on initial start.	Low--Summarized below
07/17/77	Following unit trip, main feedwater pumps lost on transfer of buses. Steam-driven EFWP tripped on over-speed.	Moderate--Summarized below
01/06/79	Reactor runback following turbine trip. Main feedwater valve did not close.	Moderate--Summarized below

Four incidents were reported between March and July 1977 where automatic start of the steam-driven auxiliary feed pump was defeated due to an overspeed indication. This was at first attributed to the steam supply valve opening and supplying steam faster than the governor could respond resulting in an overspeed trip. Later incidents, however, were attributed to condensation in the steam supply line that prevented the throttle valve from responding fast enough. The problem has apparently been corrected because no similar incidents have occurred since July 1977. These incidents did not result in primary system transients.

One other incident of feedwater pump failure occurred during a startup test when the reactor was manually tripped from 40% power. A momentary loss of control power caused zero speed indication on the feedwater tachometer which tripped the main feedwater pump. The operator took over control and maintained secondary flow.

Two feedwater malfunctions occurred during reactor trips from power operation. Both involved equipment failures, the loss of a vital bus due to inverter failure and a stuck-open feedwater block valve.

None of the Crystal River feedwater malfunctions resulted in primary system over-pressurization, excessive cooldown or safety injection. In all reported cases, feedwater anomalies were corrected before primary pressure and temperature exceeded limits.

In addition to the more serious events listed above, Florida Power Corporation reported five other incidents in response to item 2 of IE Bulletin 79-05A. The licensee's discussion of the seven events is included as Appendix O.

3.1.2 Three Mile Island, Unit 2 (Excluding the March 28, 1979, Accident)

There have been four transients at TMI-2 that caused initiation of safety injection. During two transients, primary safety valves opened and on one occasion (April 23, 1978) the primary relief valve failed open.

The following chronology of events at TMI-2 includes events prior to commercial operation. Initial criticality occurred on March 28, 1978, and commercial operation commenced on December 30, 1978.

Date	Event Description	Significance
04/22/77	Preoperational test stopped due to loss of level (low) in steam generators. Steam-driven emergency feedwater pump failed to start. (LER 77-37)	Moderate--Not discussed
07/17/77	Following unit trip and loss of feedwater pumps, steam-driven emergency feedwater pump tripped on overspeed. (LER 77-92)	Moderate--Not discussed
11/13/77	Loss of feedwater control while in manual operation. Reactor tripped on RC temp./pressure. (Gray Book)	Moderate--Not discussed
02/24/78	Actuation of steam line rupture matrix causing single failure feedwater pump trip. (LER 78-12)	Low--Not discussed
03/29/78	Reactor trip from low power with safety injection (S.I.) due to vital bus trip. (LER 78-21)	High--Summarized below
04/23/78	Reactor trip with feedwater anomalies. Main steam safeties failed open. (LERs 78-033, 78-044)	High--Summarized below
11/07/78	Reactor trip with S.I. due to feedwater pump trip. (LER 78-65)	High--Summarized below
12/02/78	Reactor trip with S.I. due to pinned open main feed. reg. valve. (LER 78-69)	High--Summarized below
01/06/79	During reactor runback following a turbine trip one feedwater block valve did not close--main feedwater line manually isolated and reactor manually tripped--feed reestablished using emergency feedwater pump. (LER 79-03)	Moderate--Not discussed

Date	Event Description	Significance
01/15/79	Routine turbine trip at 15% power. Condenser vacuum degraded (cause unknown) closing turbine bypass valves, lifting steam generator (S.G.) reliefs. Both relief discharge bellows ruptured. Operations resumed 01/31/79. (Gray Book)	Low--Not discussed
01/30/79	Main feed pump FWP-2B tripped. (January 1979 Monthly Report)	Low--Not discussed

Additional feedwater system anomalies occurred that did not result in LERs but were reported in monthly operating reports.

Date	Event
11/03/78	Condensate polisher operator error caused loss of feedwater and reactor trip.
11/07/78	Loss of feedwater due to heater drain pump trip caused reactor trip.
01/15/79	Steam system failure caused reactor trip. Atmospheric dump valve bellows and pressurizer instrumentation isolation valves repaired/replaced.
02/06/79	Feedwater pump 1B tripped twice at 90% power. No explanation.

March 29, 1978 - The following summary is extracted from a special report concerning the ECCS actuation of March 29, 1978, reported in LER 78-21. On March 29, 1978, TMI-2 experienced an automatic actuation of safety injection due to rapid depressurization of the reactor coolant system. Immediately prior to the incident, the unit was operating at low power for zero power physics testing.

The rapid depressurization of the reactor coolant system (RCS) was initiated by the pressurizer power-operated relief valve opening upon de-energization of vital bus 2-1V. At the time of the trip, the unit was being operated with three reactor coolant pumps running. The loss of vital bus 2-1V caused the reactor protection system to sense a 0/2 reactor coolant pump combination, in the loop in which one reactor coolant pump was actively operating and a reactor trip resulted.

The operators took immediate action by closing the RCS letdown isolation valve and verified that required safety injection components started. Followup action was hampered by the loss of temperature-compensated pressurizer level indication and reactor coolant system pressure indication powered from vital bus 2-1V. Without position indication for the PORV on the control console, the cause of the depressurization was not obvious to the operators.

The depressurization was terminated after approximately 4 minutes by re-energizing vital bus 2-1V through its alternate source. With vital bus 2-1V energized, the PORV automatically closed, and all instrumentation was returned to service. The minimum reactor coolant system pressure reached was 1173 psig.

The event of March 29, 1978, shows that loss of a vital bus can lead to loss of some of the instrumentation that would be useful during recovery from a transient condition, which was also complicated in this case by the opening of the PORV (unrecognized by the operators) on loss of the same bus.

April 23, 1978 - The following description of the TMI-2 incident of April 23, 1978, is extracted from LERs 78-33 and 78-44. On April 23, 1978, TMI-2 experienced a reactor trip while at 30% rated thermal power with three reactor coolant pumps in operation due to a noise spike on a power range detector. The reactor tripped because one RPS channel was already in the tripped state as required by Technical Specification 3.3.1.1 due to the inoperability of another RPS channel.

When the reactor tripped, the turbine tripped causing a very rapid pressure increase in the "B" steam generator and a slightly slower pressure increase in the "A" generator. Four of the six main steam relief valves lifted on the "B" steam generator and very rapidly blew steam pressure down. One main steam relief valve on the "A" steam generator lifted and also caused a rapid pressure blowdown but it was delayed about 40 seconds from the "B" steam generator. The "B" turbine bypass valve received a signal to go full open but almost immediately received a signal to go full closed due to the rapid depressurization in the "B" steam generator. The "A" turbine bypass valve received a signal to open at the proper pressure but the signal to open the bypass valve was lower in magnitude than it should have been.

The four "B" main steam safety valves and the one "A" valve failed to properly reseat. The safety valves on the "B" steam generator started to reseat just prior to 2 minutes into the event with the remainder of the "B" safety valves and the "A" safety valve reseating almost 4 minutes into the event. The steam generator pressures were between 550 and 600 psig when all safety valves reseated.

The operator took the proper immediate action in manually cutting back feedwater demand, shutting the RCS letdown isolation valve, starting a second RCS makeup pump, and opening the high-pressure injection valves on the side of the operating makeup pumps. The operator failed to recognize initially that the feed pump was in manual and did not run the feed pump back until approximately 1 minute and 20 seconds had elapsed.

The integrated control of the feedwater valves had not yet been initially tuned at the time of the event, and the valves responded much slower than expected.

Thus, with the feedwater valves slowly shutting, rapidly decreasing steam generator pressure, and a constant feed pump speed, too much water was fed into the steam generators.

The safety valves failing to reseat at the proper pressure coupled with over-feeding the steam generators caused a rapid depressurization and cooldown of the reactor coolant system. The reactor coolant temperature dropped from 583°F to 464°F in 3 minutes. The RCS shrinkage from the cooldown caused the pressurizer volume to drop below the minimum indicated level range approximately 1 minute after the reactor trip. Due to the rapid depressurization of the RCS, safety injection occurred approximately 1 minute after the trip. Pressurizer level was restored 2 minutes into the event as a result of safety injection, the turbine bypass valve shutting, and some of the "B" side main steam relief valves shutting. Feedwater latch occurred 2 1/2 minutes into the event and terminated feedwater flow to the steam generators. Feedwater latch was the key event in terminating the transient. Calculations performed immediately after the event showed that the core remained covered at all times throughout the transient.

<u>November 7, 1978</u> - On November 7, 1978, TMI-2 experienced a reactor trip during a power runback from 92% rated thermal power. Prior to the reactor trip, testing according to Test Procedure 800/05 (Reactivity Coefficients at Power) was in progress. All operating parameters were normal except for RC average temperature (T_{ave}) which had been elevated to 588°F (6°F above normal) for temperature coefficient measurement. A heater drain tank low level alarm was received. This automatically tripped the operating heater drain pumps that normally supply approximately 30% of the total feedwater flow to the suction of the feedwater pumps. The feedwater pumps tried to meet the increased feedwater demand causing a condensate booster pump to trip on low suction pressure. This automatically tripped the feedwater pump. The integrated control system (ICS) began a power runback to 55% rated thermal power based on the loss of one feedwater pump. However, due to the elevated reactor coolant system (RCS) temperature required by the testing in progress, the reactor tripped at 64% power. This trip occurred prior to completion of the power runback, as all four reactor protection system (RPS) channels received a variable temperature-pressure trip signal. At this point, the operator secured the letdown flow. A second reactor coolant makeup pump was then started prior to the safety injection. RCS pressure continued to decrease and safety injection was automatically initiated at 1640 psig, thus limiting the pressure decrease to 1550 psig at 25 seconds after the reactor trip. The decreased RCS volume caused pressurizer level to decrease below zero indicated level for approximately 30 seconds. However, calculations show that the pressurizer was not emptied during the transient. Approximately 2 1/2 minutes after the reactor trip, RCS pressure increased above 1600 psig (LER 78-65).

<u>December 2, 1978</u> - The following incident is reported in LER 78-69. On December 2, 1978, TMI-2 experienced a reactor trip from 22% rated thermal power

while switching from the startup to the main feedwater regulating valves. Prior to the reactor trip, all operating parameters were normal except for RC average temperature (T_{ave}) of 584°F. T_{ave} was higher than normal due to feedwater heaters being placed in service. Due to the changing feedwater flow, the startup feedwater valves opened, the feedwater valve differential pressure decreased to zero, prompting the operator to increase feedwater pump speed. It was later determined that the main feedwater regulating valves had been fully opened by manual hand wheel with instrument air isolated. The increased feedwater flow led to rapid RCS cooldown resulting in the reactor trip on low RCS pressure. The pressure recovered to above the safety injection set point within 17 seconds.

3.1.3 Three Mile Island, Unit 1

Two reactor trips have occurred at TMI-1 as a result of feedwater system malfunctions or that were complicated by feedwater system failures. We have no information to indicate that feedwater systems malfunctioned during other reactor trips.

Date	Event Description	Significance
05/24/78	Main feedwater pump trip due to loss of vacuum.	Moderate--Summarized below
11/18/78	Main feed pump trip due to thrust bearing problem.	Moderate--Summarized below

May 24, 1978 - On May 24, 1978, TMI-1 experienced an automatic ICS runback to approximately 60% power due to a main feedwater pump trip. While isolating one half of the "A" feed pump condenser to investigate a tube leak, an auxiliary vacuum pump tripped on thermal overload and the feed pump subsequently tripped on loss of vacuum. The unit was returned to full power the same day. No LER was issued.

November 18, 1978 - On November 18, 1978, the "B" main feedwater pump tripped as a result of performing a routine thrust bearing wear trip test. The unit ran back to 75% as a result of the feed pump trip and remained at 75% power until November 20, at which time, with both the 8B feedwater heater and the "B" feed pump repaired, the unit resumed full power operation. The cause of the trip was determined to be improper installation of the thrust bearing wear detector. No LER was issued.

There is no indication that these incidents resulted in severe or unusual primary system transients.

3.1.4 Rancho Seco

We have information on two transients at Rancho Seco that involved loss of feedwater and another transient due to a loss of a channel of the RPS that led to pressurization of the reactor coolant system. One was reported in IE Report 50-132/78-03 and the other in LER 79-01. Each is summarized below. Neither event resulted in damage to the plant.

Date	Event Description	Significance
03/20/78	Loss of non-nuclear instruments caused termination of feedwater flow. Primary pressure decreased and HPI initiated.	High--Summarized below
01/05/79	Electrical short in ICS caused feedwater valves to close to 50% position. Reactor trip on high pressure. HPI and AFW initiated.	High--Summarized below
04/22/79	Loss of Channel A of the RPS caused reduction in feedwater flow. primary pressure increased, but the PORV was not actuated because the set point had been increased per IE Bulletin 79-05B.	Moderate--Summarized below

On March 20, 1978, an excessive cooldown transient was experienced while operating at 70% power (IE Report 50-132). Non-nuclear instruments were lost including steam generator and pressurizer levels and all RCS temperatures. Loss of RCS hot leg temperature input to the ICS caused termination of feedwater flow. Reduced heat removal in the steam generators caused RCS temperature and pressure to increase. The reactor tripped on high RCS pressure followed by a turbine trip. The secondary sides of both steam generators emptied due to operation of condenser bypass valves, atmospheric dump valves and auxiliary steam loads. Although normal control room indications were lost, the computer typewriter will print alarms when set points are reached. In addition, selected plant parameters can be monitored on the ICS computer printout. With the aid of computer indication, pressurizer level was maintained by manual operation of a high-pressure injection pump. "A" steam generator level control initiated emergency feedwater injection (level control was actually lost at time zero, but the channel drifted slowly downward while "B" channel drifted slowly upward). The turbine-driven auxiliary feedwater pump had started on loss of feedwater flow.

RCS cooldown started as a result of emergency feedwater flow to "A" steam generator and possibly main feedwater pump flow (manually operated). Decreasing RCS pressure (1600 psig) actuated HPI pumps and the motor-driven auxiliary feedwater pump. Full auxiliary feedwater was initiated to both steam generators. The RCS reached a minimum of 1475 psig and was then increased and maintained at 2000 psig by manual control of an HPI pump.

Restoration of the non-nuclear instrumentation restored all lost indications and controls. Operating personnel secured the auxiliary feedwater pumps and started RCS pressure reduction using the pressurizer spray.

On January 5, 1979, an electrical short occurred in the integrated control system (ICS) resulting in loss of logic power which ran the feedwater valves back to the 50% position and caused RCS pressure to increase resulting in a high-pressure trip. Rapid RCS depressurization to 1600 psig actuated HPI and auxiliary feedwater. ICS was restored after 5 minutes, and feedwater flow increased. The operator then terminated most of the feedwater flow. Two minutes later the main feedwater pumps were tripped thereby allowing auxiliary feedwater to supply the steam generators.

During the transient, the "B" steam generator was filled to the top of the operating range, and it stayed at that level for 10 to 15 minutes. The licensee believes that the excessive feedwater to the "B" steam generator from the auxiliary feedwater system was "the most significant cause of the resulting excessive cooldown rate." This transient was reported in LER 79-01.

The licensee discussed the incident of March 20, 1978, in his reply to Item 2 of IE Bulletin 79-05A, which is included in Appendix P.

On April 22, 1979, an electrical component failed in one of the RPS channels. Inverter failure caused loss of power to RPS Channel "A". Loss of power to reactor coolant flow instrument causes the signal to the ICS to indicate "no reactor coolant flow." ICS can receive signal from "A" or "B" RPS channel. The ICS was using "A" at the time of the transient. The ICS therefore reduced main feedwater flow to both steam generators and automatically ran the steam generator levels down to low level (30 inches) as designed.

Because of loss of heat removal in the steam generators, the primary coolant system pressure increased until it reached the high-pressure reactor trip at 2300 psig at 16 seconds. The reactor coolant high-pressure trip channels were being reset (three of four were already done) at the time from 2355 psig to 2300 psig as a result of IE Bulletin 79-05B of March 21, 1979.

The maximum reactor pressure reached was 2330 psig, which is below the new IE Bulletin 79-05B PORV set point of 2450 psig (old set point was 2255 psig). The PORV backup valve was closed during the transient because of previous seat leakage. Upon the occurrence of the event, the backup valve was immediately unblocked. After the transient, the block valve was again closed.

Auxiliary feedwater did not start and was not required to start. Auxiliary feedwater automatically starts on (a) loss of both main feedwater pumps (P<850 psig), (b) all RCPs tripped, or (c) ECCS SFAS signal. Low reactor pressure reached during the transient was about 1855 psig at approximately 4 minutes. The operator manually initiated one HPI system to maintain system pressure. HPI was set to be manually initiated at about 1600 psig. The plant was returned to service on April 23, 1979.

3.1.5 Oconee, Units 1, 2, and 3

Information received from Duke Power Company indicates that 42 feedwater transients that caused reactor trips have occurred at the three Oconee Units. Duke experience represents 17 reactor years for about 2.5 transients per reactor year. three of them were significant events for which we have information and are discussed below.

Date	Event Description	Significance
06/13/75	Unit 3 PORV opened following system transient, stuck open and rupture disc blew in quench tank (Unit 3).	High--Summarized below
07/12/76	Unit 2 experienced ICS problem during shutdown. Reactor tripped on high pressure and PORV lifted. Quench tank rupture disc blew.	High--Summarized below
12/14/78	Unit 1 feedwater pumps tripped, steam generators went dry, HPI actuated and PORVs lifted.	High--Summarized below

On June 13, 1975, Unit 3 reactor power was being reduced from 100% to 15% when a system transient resulted in opening the PORV. The relief valve opened when RCS pressure reached 2255 psi and failed to close when pressure fell below 2205 psi. Control room indicator lights did not show that the valve was still open. Consequently, RCS pressure dropped, and the reactor tripped on low pressure and the HPI system actuated. The operator closed the relief block valve immediately after the reactor trip but reopened it because of rapidly rising pressurizer level. The block valve was finally closed when RCS pressure level reduced to 800 psi, and the transient was terminated.

The transient and associated events also caused the quench tank rupture disc to rupture, and approximately 1500 gallons of reactor coolant were released to the containment sump. It was subsequently determined that the relief valve was stuck in the open position because of heat expansion, boric acid crystal buildup on the valve lever, rubbing of the lever against the solenoid brackets, and bending of the solenoid spring bracket.

On July 12, 1976, Unit 2 was shutting down when an ICS problem caused feedwater oscillations. The reactor tripped on high pressure, the primary relief valve opened and apparently ruptured the quench tank disc. The ruptured disc was unnoticed at the time, and the unit was restarted and ran for about a week before the ruptured disc was discovered.

On December 4, 1978, Oconee 1 was at 98% power. An electrical short caused an ICS T_{ave} recorder error which caused ICS to withdraw control rods. The reactor tripped on high T_{ave}. Both normal feedwater pumps tripped on high discharge pressure. The emergency feedwater pumps were reset and started. Two hours later both steam generator levels dropped to 6 and 0 inches, respectively (30 inches is normal). "A" steam generator level was restored within three hours. "B" steam generator level took 8 hours to fill through the emergency feedwater header. Apparently, malfunctioning of valves in the normal and emergency feedwater paths caused the long fill time for steam generator "B". The HPI was actuated on low reactor coolant system pressure during the event, but from the information available it is not clear when this occurred. The PORV lifted but operated normally.

The two incidents discussed above, which resulted in rupturing quench tank discs, were not initiated by feedwater system failure but were included because of the similarity of the reactor system transients. In other words, these events illustrate that primary transients involving relief valve operation and HPI actuation can be initiated by causes other than feedwater system malfunctions.

Duke Power Company reported the above incidents plus two additional incidents in their reply to IE Bulletin 79-05A. Their discussion is included in Appendix Q.

3.1.6 Davis-Besse Unit 1

Two feedwater type events were reported to have occurred in 1977 at the Davis-Besse 1 facility and are discussed below:

Date	Event	Significance
9/24/77	Followng feedwater system trip, PORV opened and failed to close. HPI initiated and quench tank rupture disc blew out. Operator terminated transient by closing PORV block valve.	High--discussed below
11/29/77	Following loss of offsite power resulted in primary coolant shrinkage and loss of pressurizer level indication.	Moderate--discussed below

On November 29, 1977, a reactor trip and subsequent turbine trip occurred. Immediately following the trip, plant operators opened the generator main breakers station load to startup transformers "01" and "02". This de-energized the 13.8 kv "A" and "B" buses.

About 1 minute after the turbine trip, both diesel generators started but diesel generator A tripped on overspeed. In less than a minute, the "A" and "B" buses were manually transferred to the startup transformers "01" and "02", which provided the required redundant power sources.

This occurrence was determined to be a procedure error in emergency procedure 1202.03, "Turbine Trip Emergency Procedure." The procedure incorrectly called for tripping the turbine generator output breaker after a turbine trip; this does not allow the automatic transfer to occur on 13.8 kv "A" and "B" buses.

Offsite power was restored in about 11 seconds on "B" bus and in about 25 seconds on "A" bus. Decay heat was removed by natural circulation following the incident.

Of special significance during this event is the reduction of pressurizer level due to primary coolant volume shrinkage. Inspection and Enforcement Report 50-34/78-06 documented that pressurizer level had gone off the scale. Also noted during the event was the fact that T_{cold} went off the scale (less than 520°F) and that makeup flow monitoring was limited to makeup flows less than 160 gpm; however, makeup flow may be substantially greater than this value.

On September 14, 1977, an event occurred that is similar in many respects to the TMI-2 incident. The reactor was operating at 9% power. A spurious signal resulted in a half-trip of the steam feedwater rupture control system (SFRCS). This caused the startup feedwater valve on the No. 2 steam generator to close. (This is the normal feed path at low power level.) Closure of this valve resulted in a low level in No. 2 steam generator which then resulted in a normal full trip of the SFRCS for this condition and initiation of the SFRCS. SFRCS initiation closes both main steam isolation valves and initiates feedwater flow to both steam generators from their individual steam-driven auxiliary feedpumps.

The half-trip and resulting full trip of the SFRCS caused a reduction in heat removal from the primary system and a corresponding temperature/pressure rise in the primary system. The pressure rise in the primary system caused the pressurizer power-operated relief valve to lift. This valve then rapidly oscillated closed-open approximately nine times and remained in the full-open position.

The temperature rise in the primary system caused an increase in the pressurizer level, and the operator manually tripped the reactor because of high pressurizer level approximately 2 minutes after the half-trip on the SFRCS occurred.

The pressurizer power-operated relief valve, in the full-open position, rapidly reduced the primary system pressure, and a safety features actuation system (SFAS) trip occurred at the 1600 psi set point of the primary system. The PORV discharge goes to the pressurizer quench tank, which became overloaded and overpressurized, and at approximately 4-1/2 minutes after reactor trip the rupture disc in this tank relieved due to overpressure, thereby venting into the containment. Approximately 20 minutes after reactor trip, the operators diagnosed the reason for the primary system depressurization as being the PORV and, from the control room, closed the motorized block valve ahead of the PORV, terminating the blowdown of primary coolant to the containment.

Subsequent operator action using makeup pumps and high-pressure injection pumps stabilized the primary system pressure and pressurizer level and a controlled shutdown to cold shutdown conditions followed.

Concurrently, No. 2 steam generator went dry. This resulted from the failure of the No. 2 auxiliary feedpump to come up to full speed following the SFRCS trip. This feed pump came up to approximately 2600 rpm and stayed at this level with no flow to the steam generator until approximately 12 minutes after reactor trip when the operators placed the control in manual and brought it up to full speed (commencing feedwater flow to the steam generator).

The depressurization of the primary system resulted in saturated conditions in the primary system, but evaluation has shown there was no appreciable boiling in the core. The pressure/temperature transients in the primary system components including the steam generator, reactor coolant pumps and fuel were severe, but analysis and subsequent pump testing indicated that the transients experienced on the primary system did not damage pumps or fuel.

Failure of the PORV to close following actuation can be attributed at least in part to human error because the seal-in relay had been removed from the system. This relay holds the PORV open until reset pressure (2205 psig) is reached, at which time the PORV closes. Without the relay on the system, the PORV reseated below the set pressure of 2255 psig and thereafter oscillated open and closed approximately nine times and finally jammed in the open position.

The Davis-Besse 1 event is similar to the accident at TMI-2 of March 28, 1979, with several notable differences: initial power level (9% vs 98%), operating history (one effective full power day versus infinite irradiation), and decay heat removal (auxiliary feed to one steam generator versus none).

Analyses were performed by the licensee and B&W concerning this event in late 1977 and 1978. These analyses were generally based upon existing models used for feedwater types of transients using bounding assumptions. They did not consider the sort of additional failures later experienced in the TMI-2 accident which led to voiding in the RCS. In addition, long-term cooling by natural circulation was not included in the analysis.

In addition to the event summarized above, Toledo Edison reported four additional incidents in their reply to IE Bulletin 79-05A. Their discussion is included in Appendix R.

3.1.7 Arkansas Nuclear One, Unit 1 (ANO-1)

Review of feedwater-related incidents at ANO-1 described in LERs did not result in any significant transients. Arkansas Power and Light Company (APLC) in their reply to IE Bulletin 79-05A cited two incidents that involved momentary loss of pressurizer level following a reactor trip from 100% power. Subsequent tuning of the integrated control system apparently solved the problem.

APLC also reported that a PORV failed to close after actuation during plant start-up testing in 1974. This was attributed to improper venting. The venting was corrected and, on the several later occasions when the PORV lifted, it closed properly. They are discussed in Appendix S.

3.2 Summary of B&W Experience with Power-Operated Relief Valves

A review was made of operating experience with B&W pressurizer power-operated relief valves (PORVs). Other reactor plants also use PORVs. A survey of licensee event reports (LERs) indicates that B&W plants have experienced six actuations of PORVs that resulted in, or were a result of, a violation of plant Technical Specifications. Recent statements by B&W indicate that on about 150 occasions PORVs have actuated at B&W facilities. Information on PORV actuations would not be routinely reported to NRC unless a Technical Specification violation occurs. The need to consider more effective reporting requirements as well as the use of the information should be evaluated further.

On several reported occasions, the PORV failed to close when system pressure was reduced: (a) one was due to improper venting (ANO-1 during startup testing in 1974); (b) one was due to equipment failure (Oconee 3, June 13, 1975); (c) one resulted from an overpressure transient with a human error (Davis-Besse 1, September 24, 1977); (d) one was due to deenergization of a vital bus (TMI-2, March 29, 1978); and (e) one is of unknown cause at this time (TMI-2, March 28, 1979). Considering the TMI-2 accident scenario, items (b) and (c) can be said to be precursor type events; thus, there are three failures of PORVs that lead to conditions requiring HPI actuation such as at TMI-2.

Based on this experience, the estimated failure rate from all causes is 2×10^{-2} per demand (one expected failure for every 50 actuations). Preliminary failure rate estimates made by the NRC Probabilistic Analysis Staff (PAS) are consistent with this number. Consideration should be given to the merits of upgrading the valves and associated control and power equipment per GDC-14; or, as an alternate, consideration should be given to closing the relief valve and block valve during power operations.

PORVs used at B&W plants are 2-1/2" x 4" Dresser valves except at Davis-Besse 1, which uses a 2-1/2" x 4" Crosby valve. These valves used by B&W for pressurizer relief cannot be tested without removing them from the pressurizer and placing them in a special test facility. There is currently no requirement to test the valves.

NRC has required flow testing of PORVs on some Westinghouse plants as a result of overpressure protection reviews, but to date has not required testing at any B&W plants. It is our understanding that none of the B&W PORVs have been tested since initial installation. However, the actuating solenoid may have been tested by energizing with the block valve closed in some instances. In general, PORVs are not rated for two-phase or water-solid discharge conditions.

A review of LERs submitted on Westinghouse and C-E plants showed no instances of PORV actuation during transients in which a Technical Specification was exceeded.

3.3 Summary Comments on B&W Feedwater Transients

The events reviewed involved many different types of equipment malfunctions or errors that resulted in some perturbation of the feedwater system. Many of the equipment failures that initiated transients resulted in degraded performance of the main feedwater system or emergency feedwater system.

In some of the transients reviewed, both the main feedwater and emergency feedwater operated as designed (i.e., responded to other plant equipment malfunctions), but the primary system still was subjected to a pressure transient, which in some cases resulted in safety injection or lifting of power-operated relief valves.

Feedwater anomalies that contribute to severe primary system transients in many cases represent expected feedwater system responses to other plant equipment failures.

The instances of PORV lifting and subsequent failure to close are unacceptably high since a small break LOCA is created by such a failure (about one failure for each 50 actuations based on experience to date). Although procedures dealing with stuck-open PORVs exist, it is not clear that such procedures have been used in a timely way because of operator failure to recognize that a valve was stuck open.

The depressurization of the primary system and subsequent HPI initiation, either from overfeeding steam generators or from inventory loss, results in RCS transients that are difficult for the operator to control. In those instances in which the operator was responding to increasing pressurizer levels, his transient response procedure may not have been appropriate.

Although emergency feedwater is necessary to cool down the primary system following a loss of main feedwater, it has a small effect on the initial (primary) transient, i.e., even though AFW system works normally, PORV actuation and/or high-pressure injection can occur. Recent actions by licensees in response to IE Bulletin 79-05B would reduce the potential for PORV actuation due to raising its set point and lowering the reactor trip set point.

The outcome of the incidents that include equipment failure is dependent on timely and proper operator action. For feedwater trips without further equipment failures, no operator action is required. This means that the operator must recognize an abnormal system response.

As noted in the discussion of the September 24, 1977, event at Davis-Besse Unit 1 (Section 3.1.6) and the June 13, 1975, incident at Oconee 3 when the RCS pressure reduced to 800 psi, a feedwater transient (partial or full loss) plus a PORV stuck open can result in void formation in the RCS.

In addition, a study should be made by NRC of the entire reporting and data-assembly processes followed to accumulate and assess the significance of operating plant data. In particular, means should be developed to identify events of such recurring frequency that merit prompt attention by NRC; i.e., those events that frequently challenge the safety systems.

4.0 OPERATOR TRAINING AND ACTIONS

4.1 General Training

Training programs for operator and senior operator licenses vary depending upon whether the applicant will be licensed prior to or after initial criticality of the facility.

4.1.1 Precritical Applicants

The training programs for precritical applicants of B&W-designed power plants follow the same patterns as training programs for all other precritical applicants. The programs described below are for individuals with no previous nuclear experience. Training programs for individuals with nuclear experience are modified as appropriate.

In the first phase of training, the applicants are introduced to (a) the nuclear and chemical processes that occur in an operating reactor, (b) radiation and its effects, and (c) the necessity of operating a reactor in a responsible manner. The programs last for 12 weeks and conclude with each applicant participating in a 1-week laboratory course at a research reactor. This training includes operation of the research reactor.

In the second phase, the applicant attends a design lecture series where he learns the generic product lines and operating characteristics of the type of facility he will operate. This program lasts 6 weeks.

In the third phase, the applicant operates the controls of a nuclear power plant simulator during normal, abnormal, and emergency conditions. As part of this training, the applicant resides at an operating power plant to observe day-to-day plant operations beyond those that can be taught in the simulated control room. This part of the program lasts 4 1/2 months. At the conclusion of the course, the applicant must successfully complete a written examination and an operating test similar to an NRC examination.

In the final phase of training, the applicant returns to his facility to attend classes on the design features of the facility, write operating procedures, perform construction check outs and run preoperational tests of equipment. This phase lasts approximately 1 year. Just prior to taking an NRC examination, the applicant returns to the simulator training center for a 1-week refresher course.

4.1.2 Post-Critical Applicants

Individuals who apply for licenses after the facility has obtained criticality normally receive all of their training at the site. The programs are similar in scope to the programs for the precritical applicants. They include 3 months of control room experience. Individuals who participate in preoperational testing and startup testing do not normally attend a simulator course, although some may attend a 1- or 2-week simulator course. Most of these individuals have been at the plant for 3 or 4 years going through the normal job progression prior to sitting for the NRC examination.

During the training programs, described in Sections 4.1.1 and 4.1.2, the applicants are impressed with the need to use and adhere to written procedures for normal, abnormal, and emergency operations. The training programs, however, are also designed so that the individuals became intimately familiar with their plant and its operation so that they may reason their way through various transient situations and take appropriate action while remaining within the boundaries of the operating procedures and other administrative directives.

4.1.3 Requalification Programs

Licensed personnel are required to participate in requalification programs. These programs consist of annual examinations, continuous and preplanned lecture series, control manipulations, review of emergency procedures and changes to facility design, procedures and the license. An appropriate simulator may be used for control manipulations.

Training programs for plant personnel are already rigorous and comprehensive. The NRC-administered examinations require the applicant to display considerable detailed knowledge of his facility, its operating characteristics, as well as normal, abnormal, and emergency procedures for the facility.

However, there are apparent weak areas in the training programs. A thorough review of the programs conducted at simulator training facilities is necessary.

In the present training programs, when the simulator is initialized for a particular training demonstration, all systems, valves, pumps, etc., are in the correct position for that mode when the student enters the scene. The student is not required to verify or realign the various components.

During exercises that involve abnormal operations, both during training and examining, emergency systems are actuated and perform as expected every time. Instrumentation also responds in the correct manner during the course of an abnormal or emergency operation. However, abnormal operation of emergency equipment during normal and abnormal events is not stressed.

Operator and senior operator applicants receive essentially the same training except that the senior operator is expected to demonstrate a better understanding of operating characteristics, fuel handling, and administrative procedures. Little emphasis is placed on evaluating the senior applicant's ability to manage an abnormal and/or emergency condition.

Requalification programs permit operators and senior operators to execute all of their control manipulations at the facility. The vast majority of these are normal manipulations. Therefore, the majority of the operators walk through abnormal and emergency procedures. Consideration should be given to requiring all operators to receive simulator training as part of the requalification programs.

Although all current PWR training programs and operating procedures are geared toward the prevention of void formation in the RCS, these procedures may be inadequate to (a) alert the operator to the significance of void formation in the RCS, (b) tell the operator what parameters to monitor as indicators of the presence of voids in the system, and (c) instruct the operator in positive actions to suppress or accommodate voids in the system. Until very recently, simulator models did not include RCS responses with void formation.

It is especially the areas of abnormal or emergency procedures that should be addressed during the review of training programs. With this is mind, a reevaluation of existing training programs will be performed for all nuclear power plants.

As part of the actions that will be taken at all the B&W plants recently shut down, each operating crew will complete retraining on the B&W simulator for the TMI-2 accident.

4.2 General Operating Procedures

Operating procedures are prepared in accordance with Regulatory Guide 1.33, Appendix A, Quality Assurance Program Requirements (Operation), and Sections 5.3.2, 5.3.9, and 5.3.9.1 of ANSI N18.1/ANS 3.2 entitled, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." The operating procedures are written by the facility operating staff. The reactor vendor supplies reference material to serve as a basis for the procedures. The procedures are reviewed by the Plant Operations Review Committee or a similar review group comprised of senior supervisory personnel. The procedures are then approved by the plant superintendent. The procedures are forwarded to the NRC regional I&E inspector for review prior to loading the fuel into the reactor. The NRC Operator Licensing Branch (OLB) uses the procedures to develop questions for examinations. If OLB examiners determine any inadequacies in the procedures, they inform the I&E inspector of their concerns.

It is clear from the TMI-2 accident that facility procedures should be reviewed to assure that they realistically assist the operators in coping with an abnormal or emergency condition.

NRC should also explore means for improving the procedure system. Particular emphasis should be placed on indexing, ease of retrieval, clarity of instructions, and updating provision.

The adequacy of safety-related operator action procedures should be determined on an appropriate simulator as part of the review process. Review of procedures should be more closely coupled to the knowledge gained from unanticipated events. *Aids to assist the operator to diagnose instrument response should be part of the* emergency procedures; for example, pump head versus flow curves could be of use at the console.

A new section of emergency procedures should be developed that addresses shutdown operation with degraded equipment and instrumentation. These procedures should be included in Regulatory Guide 1.33.

4.3 Human Factors

WASH-1400, the Reactor Safety Study (RSS), and the critique of the report performed by the Risk Assessment Review Group (NUREG-CR/0687) addressed the role of the operator during the course of an accident.

To quote from the RSS:

> "On the basis of interview, observation, a visit to a training center, and review of training materials, the level of training of nuclear power plant personnel was judged to be outstanding. For example, interviews with control room operators revealed a clear understanding of normal reactor operation. They can readily describe the events occurring in normal on-line operation and have a clear conceptual picture of the processes involved. (In one interview an operator who was considered by his supervisor to be 'below average' for operators at the site demonstrated the above thorough understanding.) Therefore, for routine maintenance, calibration, and control room operations, a high degree of trained-in excellence has been assumed with associated high estimates of human reliability."

However, the RSS indicates something less than complete satisfaction with operator response to emergency situations based on "talk-through" of responses to simulated emergencies. As a consequence, the report assigned relatively high error rates to operator actions required soon after a major emergency such as a large LOCA. Since there were no nuclear power plant human reliability data available at the time of the report, data from other studies were used to assign average operator error rates. The results of two of the studies indicated that assignment of high error rates to operator actions during a stress situation was appropriate.

> "Two studies that merit mention here are both considered classics in the area of human factors. In one study by the American Institutes of Research critical incidents were collected from Strategic Air Command aircrews after they survived in-flight emergencies (such as loss of engine on takeoff, cabin fire, tire blowout on landing, etc.). The critical incident average error rate was 0.16; that is, 16% of the time, the critical actions of the aircrews in such stress situations either made the situation worse or did not provide relief.
>
> "In the second study, conducted by the Human Resources Research Organization, Army recruits were subjected to simulated emergencies such as the increasing proximity of falling mortar shells in their command posts. The recruits were exposed to these simulated emergencies in such a way that they believed the situations to be real. As many as one third of new recruits fled in panic, rather than perform the assigned task that would have resulted in a cessation of the mortar attack. These studies have yielded indications of the devastating effects that very high stress levels can have on the performance of even thoroughly trained, reliable personnel."

The Risk Assessment Review Group recognized the difficulty of incorporating operator error into fault tree analysis. However, the Group believed that the RSS underrated the role of operators and other employees in mitigating or controlling some potential accident sequences, particularly those that required a reasonably lengthy time to degenerate.

In response to the findings and recommendations in these reports, and because of other NRC concerns, several studies examining examining operator response are presently under way.

NRC is sponsoring a safety-related operator action study to determine, with better precision, the times required for operator response. A second study sponsored by NRC addresses human reliability based on a detailed review of Licensee Event Reports (LERs) to develop reliability numbers for risk assessment studies. Finally we are sponsoring a human reliability study regarding maintenance and instrument calibration tasks.

In addition to these NRC studies, the Electric Power Research Institute (EPRI) is sponsoring studies on human engineering in the control room, an assessment of advanced control rooms, and conducting performance measurements.

The applicable results of all these studies will be factored into the regulatory process as they become available.

4.4 Operator Actions During Recovery from Loss of Feedwater Transient

4.4.1 General Procedures

Operator response to a loss of feedwater transient consists of verifying certain automatic actions and performing several immediate manual actions. These are specified in operating procedures. The immediate automatic and manual actions are specified in the emergency procedures and are committed to memory by licensed operators. In the case of a feedwater transient that leads to a reactor trip, the operator would be expected to perform the emergency procedures for a reactor trip and for loss of feedwater. In addition, the operator would examine the written emergency procedures and verify that all immediate actions had been performed. After this verification, the operator would follow the long-term instructions as provided in the station procedures.

If a situation such as the one that developed at TMI-2 were to recur, it is clear that the operators would need to recognize the situation (i.e., a stuck-open PORV) and utilize existing procedures for a stuck PORV and a small break LOCA. From the discussion in Section 3.0 and the TMI-2 accident, it is not clear that this was done in a timely way during previous events.

4.4.2 Operator Actions in Response to the TMI-2 Transient of March 28, 1979

The following discussion is based on preliminary information and is subject to change in the light of information still being developed. Following loss of main feedwater supply to the steam generators, the initial indication to the TMI-2 operators was a turbine-generator trip and 8 seconds later a reactor trip due to high pressure. The turbine trip occurs automatically on loss of both main feedwater pumps. When the turbine trips, pressurizer level and pressure begin to increase. The ICS should begin to run the plant back by driving in control rods and closing the main feedwater regulating valves. Also, the power-operated relief valve on the pressurizer opens at 100 psi above the primary system pressure of 2155 psig. These automatic features are designed to enable the reactor to continue to operate following a turbine trip. In this case, the pressure increase was too rapid and a reactor trip occurred at 2355 psig.

The operators at this point apparently believed it was a typical reactor trip and were following their emergency procedure for this event. In addition to their verifications, the operators were required to close the reactor coolant system (RCS) letdown isolation valve and start a second makeup pump. These actions were apparently performed. Steam generator levels automatically decrease to 30 inches on the startup range.

There are no flow indications for auxiliary feedwater flow in the control room. During the first minute into this transient, the operators apparently believed that there were no problems with the auxiliary feedwater because the steam generator levels were decreasing as designed and the three auxiliary feedwater pumps were running.

After approximately 1 minute, the pressurizer level began to rapidly increase. This was an unusual indication to the operator. Both training and the reactor trip procedure usually alert the operator to maintain pressurizer level because it normally drops considerably following a reactor trip. At this point, two makeup (high-pressure injection) pumps were running and the power-operated relief valve was still open. The only position indication on this relief valve is a light that shows if the solenoid that actuates the valve is energized or de-energized. Once system pressure dropped below 2205 psig (where the valve should have closed), this light apparently went out.

When the pressurizer level was at 385 inches, the operators attempted to control it first by throttling the injection valves and then by tripping one of the HPI pumps. This was done about 5 minutes into the event. Saturation conditions in the RCS were reached and the pressurizer level went off the scale shortly thereafter. The pressurizer level remained off the scale for several minutes and the operator stopped the second HPI pump. This was a significant operational error because system pressure was already 100 to 200 psi <u>below</u> the actuation pressure for safety injection.

A cautionary statement in the followup actions of the Loss of Reactor Coolant System Pressure procedure states:

> "Continued operation (of safety injection) depends upon the capability to maintain pressurizer level and RCS pressure above the 1640 psig Safety Injection Actuation setpoint."

This statement appears in the procedure for the situation in which safety injection was manually initiated. It does not appear later on in the procedure under automatic safety injection (SI) initiation, which occurred during this accident. The operators, however, appeared to be concerned with a water solid pressurizer and paid insufficient attention to RCS pressure.

During this period of time, the operators were also becoming aware that steam generator levels were being indicated significantly below their control set point and pressures were decreasing. Eight minutes into the incident the operators discovered that the emergency feedwater injection block valves EF-V12A and EF-V12B were shut and opened them from the control room panels resulting in auxiliary feedwater flow to the steam generators. When feedwater was initiated to the steam generators, a heat sink was provided for the RCS which further decreased primary system pressure.

There is no evidence at this time that the operators were consulting any procedure other than the reactor trip procedure. The Loss of Steam Generator Feed Emergency Procedure directs operators to verify that emergency feedwater valves EF-V11A and EV-V11B are in automatic and controlling steam generator levels. When the block valves, EF-V12A and EF-V12B, were opened, EF-V11A and EF-V11B should have received a wide-open signal from the ICS.

Based on preliminary evidence, it appears possible that a clear supervisory role had not been established during this period in order to assess the overall plant situation. The personnel involved seemed to have concentrated on a specific system or abnormal parameter. The actual reason for the system pressure decrease was not adequately addressed.

From 4:20 a.m. to 5:00 a.m. the operators allowed the RCS to stabilize at saturated conditions of 1015 psig and 550°F. They were then beginning to experience problems with the reactor coolant pumps, i.e., decreasing flow and high vibration. At 5:14 a.m., both pumps in loop B were tripped. This appears to have been a joint decision by the personnel in the control room. There is evidence that supervisory personnel were present at this time and the decision to stop the pumps was not made solely by the operators. The concern was that the pumps were not meeting the net positive suction head requirements. After observing the flow fluctuate for about 27 minutes, the remaining two RC pumps were stopped.

During this time, the B steam generator was isolated because the operators believed it was leaking steam into containment. The level in A steam generator was increased to promote natural circulation.

Because supervisory personnel were present in the control room at this time, the decision-making process was no longer solely the responsibility of the shift operating crew. Up to this point, the significant human errors appear to include the following:

1. The prior closure of emergency feedwater valves EF-V12A and EF-V12B and the failure of all control room personnel to be aware of and correct this situation;

2. The termination of high-pressure injection flow when system pressure was significantly below the actuation point;

3. The apparent lack of attention to decreasing system pressure and failure to systematically observe plant parameters to determine the reason for this pressure decline (the power-operated relief valve stuck open);

4. The decision to stop the reactor coolant pumps and the failure to verify or ensure natural circulation flow;

5. The apparent lack of use of the appropriate emergency procedures (i.e., loss of steam generator feed and loss of reactor coolant system pressure); and

6. The failure to follow the procedure for a stuck-open PORV.

4.5 General Comments

In addition to those follow-up actions identified in earlier parts of Section 4.0 above, the following recommendations should be considered.

1. If ECCS actuation occurs, operators must allow sufficient time for the system to respond prior to defeating the system. Other guidance for minimum ECCS operating time has been provided through IE Bulletin 79-05.

2. Other potential methods for coping with a loss of the primary heat sink should be investigated. Analyses and procedures should be developed for use of pressurizer relief and safety valves and high-pressure injection as heat sinks.

3. Consideration should be given to using tape recorders that record operator(s) conversations when a trip occurs. It will help the operators to write logs and provide for a real time record.

4. IE Circular 76-07, Inadequate Performance By Reactor Operating and Support Staff Members, should be reviewed and reissued, if necessary. This circular addresses the need for utility management to review and take appropriate action on LERs that involve facilities similar to theirs.

5. There will always be a residuum of possible but not postulated and analyzed situations. To address this, and as an attempt to extend the defense-in-depth concept, we should study ways to make the operator a more effective recovery agent or incident/accident mitigator. Such a study should look for ways to (a) prevent (inhibit) inappropriate actions and (b) promote productive intervention. An element of the study that could serve both purposes would be an investigation of methods that would furnish the operator with correct, current, digestible information regarding principal plant conditions (i.e., processes, systems and equipment). The means by which the operator would best use this information should also be considered, however, such means should not be so rigid as to preclude expedited and improvised actions for the operators for unanticipated phenomena.

5.0 LICENSING BASIS AND REGULATIONS

5.1 Licensing Overview

The NRC makes the determination before a license is granted that there is reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. A body of requirements has been provided for the design and operation of nuclear power plants to ensure safety. The principal elements of these requirements are contained in the Code of Federal Regulations, Title 10 Part 50 especially in Appendix A, General Design Criteria (GDC). License applicants are required to include the results of a safety evaluation covering the significant design features of the reactor plant for review by the NRC prior to construction and operation. These are called the preliminary and final safety analysis reports (PSAR and FSAR). In order to organize the PSAR or FSAR for each plant into a document treating all requirements, a Standard Format and content guide (NUREG-75/094) was developed to specify information requirements for the Safety Analysis Reports. To assure a consistent review of each plant's Safety Analysis Report by NRC, a Standard Review Plan (NUREG-75/087) was developed. In addition, Regulatory Guides have been developed to more specifically provide interpretations of the GDC acceptable to the NRC staff for the design of nuclear power plants.

A defense-in-depth approach to safety is embodied in the regulations. This leads to multiple barriers against the release of radioactive material. Similarly, reactor and plant systems important to safety are constructed and tested to criteria consistent with their importance to safety namely, the fuel cladding, the primary system pressure boundary, and the containment building. Then engineered safety systems are provided to mitigate the consequences of various postulated events. Safety systems are required to be designed to accommodate single active failures in these systems in addition to the effects of the initiating event without loss of their safety function. Some passive failures also have to be considered. Not all safety systems in older plants meet the single failure criterion as it is now applied, e.g., the auxiliary feedwater system at Oconee is not single failure proof.

Preoperational and startup tests are performed on each plant to assure that the plant and its safety systems are operational and can perform as designed. Technical Specifications identifying and limiting conditions for plant operation are added as an appendix to the Operating License. Maintenance, inspection, and operational considerations are subjects of interaction between the NRC and the licensee throughout the life of the plant.

The operators of nuclear power plants are subject to licensing requirements specified by NRC. The licensing process includes initial training in nuclear technology, understanding of generic designs, and simulator training. Subsequently, final training takes place at the home facility where actual experience is obtained, including the use of procedures for normal, abnormal, and emergency operations. The culmination of this training program is the NRC Reactor Operator License Exam which must be passed in order to be licensed to operate the plant (see Section 4.0).

In this section of the study, certain aspects of the NRC licensing process will be evaluated in light of the TMI-2 accident of March 28, 1979. Specifically, the following will be addressed:

1. Loss of feedwater events for B&W reactors including a consideration of initiating events that lead to pressurization of the primary system causing the safety valves to actuate. (In actuality, the relief valves would operate before the safety valves; however, no credit is given for their actuation.)

2. Status of models used in safety analysis, especially with regard to transients and small breaks.

3. Standard Review Plans (SRPs) and their applicability to transients and small breaks.

4. Technical Specifications and their requirements for the operators to cope with transients and/or small break events.

5.2 Final Safety Analysis Reports for Operating B&W Reactors

In general, the loss of feedwater transient analyses that have been performed and reported in the Final Safety Analysis Reports (FSAR) for B&W reactors have focused only on a loss of normal feedwater. Loss of all feedwater (i.e., failure of both main and emergency feedwater systems) is not considered in the course of a usual case review. This is consistent with current and past regulatory practice as it was believed that a loss of all feedwater could only occur after multiple and unlikely equipment failures. Human error to lock-out a system (such as occurred on TMI-2) had been considered to be highly unlikely.

Loss of feedwater transients are not the only anticipated occurrences that result in primary system pressure transients. Some others are a loss of off-site power, a turbine or generator trip, certain small break events, and events that would result in a loss of secondary system heat removal, e.g., a main steam line break or a rupture of a steam generator tube.

Although not specifically required by regulations, some analyses for a total loss of feedwater accident have been performed in part on occasions. These were performed as part of the staff's review of related transients (e.g., see Appendix V for Three Mile Island, Unit 1, Design Review for Consideration of Effects of Piping Systems Breaks Outside Containment, FSAR Supplement 2, Part IX) and in response to specific ACRS questions.

Following is a brief discussion of an example of each of the types of analyses of feedwater events that have been performed.

5.2.1 Loss of Normal Feedwater

As stated above, a loss of normal feedwater is the design basis feedwater transient required to be addressed in the Final Safety Analysis Report. This type of analysis was performed for Three Mile Island, Unit 2, and the results are typical for all B&W plants (a copy of the TMI-2 analysis is provided in Appendix T of this report).

Since this transient is considered to be an overpressure event, assumptions are made in the analysis to accentuate the overpressurization. Specifically, neither power runback nor PORVs are assumed to operate. During the transient, the loss of main feedwater reduces the capability to dissipate heat-flow from the primary to secondary system. The primary system heats up, the safety valve is actuated, and the reactor trips on overpressure in the primary system. The emergency feedwater system refills the steam generators and dissipates the decay heat. The reactor core remains covered, no fuel damage occurs and offsite doses are well within the guidelines of 10 CFR 100. The actual analysis presented spans about a 20-second period. In this time, it indicates that core power and primary system pressure are moving in a safe direction relative to fuel damage and system overpressure.

The analysis that was performed did not assume opening of the power-operated relief valve nor its subsequent failure to close when the pressure decreased. Such an assumption was considered to be conservative because it would result in calculating a maximum pressure in the primary system. On the other hand, the failure of a PORV to operate properly was not evaluated completely. Although the PORV is designed to open on loss of normal feedwater, the staff may not have paid sufficient attention to the possibility it could stick open because of the attention given to assuring that a conservative overpressure would be calculated. The Standard Review Plan indicates that there should be no loss of function of any barrier other than the fuel cladding for such a transient, even when accompanied by a single failure. This aspect will have to be reconsidered in future analyses. In addition, consideration will have to be given to the valve design with regard to its ability to function under dynamic conditions including two-phase flow. The control system associated with the valve actuator is also to be evaluated as to possible upgrading to a safety grade requirement. The dynamic effects of depressurization and the potential for voiding in the reactor coolant system will need to be evaluated in future studies. These matters are discussed in Section 2 of this report.

The TMI-2 accident started with a loss of feedwater transient and, because of the stuck-open power operated relief valve, a small break loss-of-coolant accident resulted. According to the Standard Review Plan, such a sequence should have been analyzed in the licensing process, but it was not. It may have been considered to be bounded by other small break LOCA analyses.

With regard to the small break analyses, B&W generally performs such calculations down to about an area of 5 square inches at locations in the primary loop other than the pressurizer, and for relatively short time periods between 100 and 200 seconds. Further work will be necessary to review smaller breaks of the type that might be postulated based upon the TMI-2 experience. The long-term coolability of the plant will need to be evaluated especially with regard to natural circulation cooling which would be necessary for a loss-of-offsite power event. A natural circulation test was not conducted on TMI-2 during startup testing because of a test performed on the Oconee plant which is of the same general design as TMI-2. It is noted however, that natural circulation cooling was accomplished at TMI-2 on April 27, 1979.

The models that are used for small break analyses conform to Appendix K (10 CFR 50) requirements; e.g., loss-of-offsite power, minimum core cooling, and no short-term operator actions. More realistic studies of the reactor plant dynamic respnse will be needed to ensure proper tracking and understanding of the event being analyzed. These matters are now being discussed with B&W as part of the recent shutdown actions. The B&W Company submitted a letter dated April 30, 1979 describing its actions with regard to the evaluation of transients and small break LOCAs (Appendix U).

5.2.2 Steam Line Break Outside Containment Building Resulting in Complete Loss of Feedwater

This accident was analyzed for Three Mile Island, Unit 1, which is similar to Unit 2. The main difference between a steam line break and a feedwater line break (or loss of feedwater) is that during the initial transient, the steam generator blows down (depressurizes) and over-cools the primary system. The reactor trips on low primary system pressure. The analysis assumes that the primary system does not depressurize to the 1600 psi set point for ECCS actuation but rather repressurizes due to decay heat after the reactor trip. The failed steam line and associated steam generator are assumed isolated. A failure of the emergency feedwater system to supply the remaining steam generator is usually assumed.

The operator is given credit for controlling the makeup system and starting a second HPI pump after 15 minutes. This results in the primary system going solid with water and with mass and energy being released through the pressurizer valve.

The core would remain covered and cooled in this mode until the water would be depleted from the borated water storage tank (BWST). Prior to BWST depletion, the operator would initiate emergency feedwater in the remaining steam generator and initiate cooldown.

Analysis indicated that there would be some voiding in the core, and no significant fuel damage was predicted with the design power distribution. The prolonged release through the code safety valve resulted in high containment pressure and subsequent containment isolation, and actuation of the ECCS 38 minutes after the event. A copy of the TMI-1 Analysis of this event is presented in Appendix V of this report.

see TMI-1 "slurp & burp"

5.2.3 Loss of All Feedwater

During the course of the ACRS review of the Pebble Springs Nuclear Plant (a B&W plant) Construction Permit application, it was requested that the licensee consider certain questions related to a complete loss of feedwater transient. The response of the licensee, Portland General Electric Company, is included in Appendix W of this report. As in the case of the above steam line break analysis, the complete loss of feedwater transient is mitigated by relying on high-pressure injection drawn from the borated water storage tank to maintain primary system inventory and pressure in lieu of the steam generators.

The Pebble Springs Nuclear Plant reactors are larger than the reactors at Three Mile Island. However, the system configuration is similar and therefore would respond in a similar manner to transients analyzed in accordance with license application guidelines. The results of the analysis of loss of feedwater illustrates that voiding is expected to occur in the system in addition to the void in the pressurizer.

5.2.4 Summary of FSAR Analyses

For most PWRs, including B&W plants, the safety analyses are carried out in time only long enough to indicate that pertinent parameters relative to core damage or overpressurization are proceeding in a safe direction. Analyses are seldom pursued out in time to evaluate operator actions, inactions, or error in judgment, or the course of natural circulation cooling in the event of a loss-of-offsite power. A "bounding" analysis is normally presented which covers a number of possible initiating events in combination with potential additional single failures. The TMI-2 accident raises the question of whether the bounding analysis approach results in a loss of accuracy in tracking individual events where possible new insights could be obtained, e.g., not including a PORV in the analysis because it is not safety grade and then allowing system pressure to rise to the safety valve setpoint. Analyses performed in 1977 and 1978 by the Davis-Besse licensee and B&W regarding the September 24, 1977, event were indicated to be conservative analyses; however, the modeling of the event led to a shortcoming of not analyzing the phenomenon of voiding in the core and long-term natural circulation cooling. As discussed previously, such factors as the interrelationship between a transient and a small break need to be given consideration. The question of reliance on safety vs. non-safety grade equipment to terminate transients deserves further study because the design requirements and operational reliability of non-safety grade equipment are not specified by NRC. It has long been recognized that new criteria are necessary to specify requirements for control grade equipment.

5.3 Status of Models Used in B&W Safety Analyses

Presently, B&W uses the TRAP-2 code for secondary side transient analyses. TRAP-2 is similar to the CRAFT code used in LOCA analyses, but has been modified to include a more detailed steam generator model. A recent (August 1978) NRC inspection of vendor quality assurance procedures for computer codes revealed that B&W lists the TRAP-2 code as a conditionally certified code, meaning that the verification of the code has not yet been completed to B&W's satisfaction. The code was submitted for NRC review in 1976. The information provided in support of the code was not sufficient to complete the review. Additional information was requested in January 1979. The outstanding questions are primarily concerned with the adequacy of the pressurizer model to calculate pressures correctly for insurges, and the experimental verification of the model. Even though the TRAP-2 code is not fully reviewed and not verified at the present time, it is still the best tool available to B&W for feedwater transient analysis. Other codes like POWER TRAIN, which was previously used for feedwater transient analysis, are still under review by NRC and are known to give nonconservative results compared with TRAP-2 at least for some events. (See, for example, the TMI-2 steam line break analysis submitted in December 1977.) Thus, all future feedwater transient analyses should use the TRAP-2 code. Reliance should be placed on older codes like POWER TRAIN and CADD only for certain transients which are determined to be within their scope. These codes only model the primary system in a single-phase fluid condition. In addition, the transient analysis provided by B&W has been usually limited to the first few minutes of the event. The staff is presently meeting with B&W (and other PWR vendors) to discuss the models and codes used for transient and small break analyses including natural circulation cooling. This activity has been included as part of the recent shutdown actions taken with the B&W plants. Because of the generic nature of this review, further consideration of models and codes should also include the GE-BWR plants.

A report entitled, "Decay Heat Removal During a Very Small Break LOCA for a B&W 205-Fuel-Assembly PWR," by C. Michelson (January 1978) has recently been provided to the staff. In this report Mr. Michelson described concerns regarding small breaks (0.05 ft^2 range) and the ability of the plant's heat removal systems to remove adequate decay heat to prevent system repressurization in the event of a loss of natural circulation or break isolation by operator action. He has also discussed concerns on slug or two-phase flow through a pressurizer safety valve. This report is presently being reviewed by the staff and will be reported on separately.

5.4 Standard Review Plans

The Standard Review Plan requirements for the loss of feedwater and other anticipated transients have been reviewed to determine how differences in the present requirements would have led to a better anticipation or understanding of the events associated with the TMI-2 accident. There are two areas that would have an impact on the NRC's capability to predict or correct what occurred at TMI-2.

1. Under the "Areas of Review" and also the "Review Procedures" subsections of the Standard Review Plan Section 15.2.7, it is stated that "transients are reviewed to the point where a stabilized condition is achieved."

   As noted during the discussion of the analyses presented in the FSAR, the staff has accepted analyses wherein the critical parameters had entered a stable region and were so continuing. This interpretation of "a point where stabilized conditions have been achieved" should be a subject of reassessment especially with regard to achieving natural circulation cooling.

2. The Standard Review Plan (Section 15.1) states that "An incident of moderate frequency in combination with any single active component failure, or single operator error, should not result in a loss of function of any barrier other than fuel cladding. A limited number of fuel rod cladding perforations is acceptable."

The staff has been aware that Anticipated Operational Occurrences (AOOs) plus a single failure are not rigorously pursued, especially with regard to a stuck-open relief valve during a transient. Such events were considered either to be within the capability of the makeup system or were covered by small break analyses; however, only a limited number of small break analyses for B&W plants were previously provided or required for staff review, and none corresponding to the stuck-open PORV.

A reassessment of moderate frequency and infrequent events and their treatment by the NRC is necessary. In this case, it is apparent that greater awareness of the review areas and assumptions is necessary. In no case, however, would the present

SRP require that multiple failures similar to those apparently associated with the TMI-2 event be considered as a design basis accident. Greater attention will be needed in considering consequential failures and operator actions based upon TMI-2.

5.5 General Design Criteria

Feedwater transients are anticipated operational occurrences (AOOs), since they are expected to occur one or more times during the life of a nuclear plant. The basic requirements for AOO's are given in General Design Criteria (GDC) 10 and 15. GDC-10 requires that specified acceptable fuel design limits not be exceeded during AOOs. GDC-14 and GDC-15 require that the design of the reactor coolant pressure boundary should preclude abnormal leakage and the design conditions of the boundary should not be exceeded during AOO's. Additional requirements specified in GDC-13 are: "Instrumentation shall be provided to monitor variables and systems over their anticipated ranges...for anticipated operational occurrences...as appropriate to assure adequate safety.... Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges." GDC-20 states the general requirements for protection systems, including the following: "The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specific acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences...."

In the light of the TMI-2 experience, it is apparent that applicable criteria were not met. Clearer guidance and implementation of these criteria by NRC are necessary. This action can generally be accomplished through revisions to the Standard Review Plan or the issuance of new Regulatory Guides following the development of the specific actions required; however, the criteria themselves should be reviewed for improvement or clarification. Interim actions at the present are being taken by issuance of the IE Bulletins (79-05, 79-05A, 79-05B, 79-06, 79-06A, and 79-08) to the licensees of light water reactor plants. These deal with placing greater reliance on a variety of plant equipment and operating parameters, rather than emphasis on one parameter only as was apparently the case for pressurizer level in the early minutes of the TMI-2 accident.

5.6 Technical Specifications

A brief study was made of the possible interaction of Technical Specifications and the Three Mile Island Unit 2 accident. Two categories are identified, the first includes those that may be overly prescriptive and that may have contributed to the course and severity of the accident. The second category involves violations that apparently led to or contributed to the severity of the accident at TMI-2.

In the first category, Technical Specification 3.4.4 of the Standard Technical Specifications requires that the pressurizer be operable with a steam bubble and a specified water level when the reactor plant is in Modes 1, 2, and 3 (power operation, startup, and hot standby). This specification may have influenced the operator to emphasize the maintenance of pressurizer level and not sufficiently emphasize primary system inventory and pressure.

There are indications that Technical Specifications were violated at TMI-2. For example, Technical Specification 3.7.1.2 requires that three emergency feedwater pumps be available during normal reactor operation (one may be unavailable for short periods of time associated with surveillance testing or maintenance). When the incident occurred, all three pumps were isolated from providing flow to the steam generator by closed valves. This violation led to complete blowdown (dry-out) of the steam generator and contributed to PORV action in the primary system. The stuck-open relief valve caused system depressurization and ultimate voiding in the reactor core.

The foregoing is an example of the interaction of the Technical Specifications and the TMI-2 accident. A preliminary review of the Technical Specifications in the light of recent TMI-2 experience indicates further consideration should be given to improving these requirements to cover off-normal situations, improved reporting requirements, and improved means to ensure that proper plant system configurations are maintained during power operation.

6.0 OTHER PRESSURIZED WATER REACTORS

6.1 Design

Representative Combustion Engineering (C-E) and Westinghouse (W) PWR designs have been compared with the Babcock & Wilcox PWR design to assess the relative reactor system dynamic behavior that would result from a complete loss of main feedwater. A summary of pertinent design information used in this comparison is given in Table 10.

Further review is being made of the C-E and W reactor plant designs in light of the TMI-2 accident. The staff has met with representatives of the NSSS designers to discuss related analyses, tests, and plant features dealing with small break LOCA, anticipated transients, operator training and procedures, and reliability of the auxiliary feedwater systems including associated controls and natural circulation capability. The results of the staff review will be presented in separate reports.

6.1.1 Combustion Engineering

The Combustion Engineering plants selected were Palisades and Millstone Unit 2. Relevant design data for these plants, which were collected from the plant FSARs and Technical Specifications, are given in Table 10.

As Table 10 shows, there is a relatively small difference in the total reactor coolant system volume between the C-E plants selected and a typical B&W reactor. The volume is about 10 percent larger for a typical B&W plant; thus, correspondingly greater coolant mass is available to store energy whenever a loss of normal heat sink occurs. Thus, all else being equal, the temperature and pressure rise (fall) in the primary system will be faster for a C-E plant than for a B&W plant for a given reduction (increase) in steam generator heat removal capability.

However, as the table shows, there is a substantially larger inventory of water stored on the secondary side of the C-E and W steam generators than in the B&W once-through steam generator (OTSG) design. Boil-off, at hot full power, will not occur for more than 1½ minutes for the Palisades plant and about 2 minutes for the Millstone unit. This heat sink storage is approximately three to four times greater than a typical once-through steam generator B&W plant. The substantially larger heat transfer buffer afforded by this larger inventory results in a relatively gradual pressure and temperature rise in the primary system whenever normal feedwater supply is lost. In addition, as seen from the table, both of

TABLE 10 COMPARISON OF KEY CHARACTERISTICS OF OPERATING B&W PLANTS WITH C-E and W PLANTS FOR THE LOSS OF FEEDWATER TRANSIENT

	B&W	W		C-E	
Characteristic	TMI-2	IP-3	D.C. Cook	Palisades	Millstone 2
Thermal rating, MW+	2772	3025	3250	2530	2560
Trip from secondary	No	Yes	Yes	Yes	Yes
Rx press trip, psig*	2355	2385	2385	2240	2385
RCS volume, $ft^3 \times 10^{-3}$	11.5	11.3	12.6	10.9	10.8
Pressurizer vol./RCS vol.	0.13	0.15	0.14	0.14	0.14
PORV capacity, lb/hr MW	40.4	118.	194	121	119
Set point, psig*	2255	2335	2335	2385	2385
Oper. margin, psi	70	100	100	150	150
SV capacity, lb/hr Mwt	249	416	388	272	231
Low set point, psig	2450	2485	2485	2485	2485
Steam gen., minutes to inventory, boil-off @ FP	0.45	1.22	1.17	1.55	1.94
Aux. FW cap motor	2@ 2.0ea	2.@1.3ea	2@1.6ea	1@1.53	2@1.1
% of design rating turbine	1@3.8	1@2.6	1@3.2	1@1.53	1@2.2
High-press inject/dead head, psi	2820	1463	1560/2590	1214	1192
Charging cap gpm @ des. press.	2@300 ea	0	400/150	300	
gpm @ 1600 psig	2@450 ea	0	0/	0	
RCP vapor trap geom	Yes	No	No	No	No
Hot leg/S.G. vapor trap geom	Yes	No	No	No	
Pressurizer loop seal geom	Yes	No	No	No	
Internals vent valves	Yes	No	No	No	

*To be revised per IE Bulletin 79-05B

the C-E plants incorporate an anticipatory reactor trip on low steam generator water level. This trip causes termination of the pressure and temperature rise in the primary system before an excessive loss of steam generator heat removal capability occurs.

Moreover, the margin between normal primary system operating pressure and the lift set point of the PORV is 150 psi. This pressure margin is about 80 psi more than originally provided in a B&W plant (B&W operating plant margins will be increased during the current shutdown). The additional margin allows for a larger transient pressure and temperature rise in the RCS before PORV actuation. The most recent analyses of the loss of feedwater transient for these plants show that the relatively gradual pressure and temperature rise in the primary system is terminated by the anticipatory reactor trip in time to avoid lifting the PORV.

In summary, the large water inventory in their steam generators makes the loss of feedwater event a slower transient for a C-E PWR than for a B&W PWR. The slow rate of the pressure and temperature rise in the primary system coupled with the anticipatory (faster) reactor trip and relatively high actuation pressure of the PORV makes the lifting of these valves unexpected. Thus, the probability of a stuck-open PORV during the cooldown or depressurization phase of a loss of feedwater event is smaller for a C-E plant than for a B&W OTSG plant.

Analyses by C-E show that when Palisades loses normal feedwater the early reactor trip will cause sufficient water to be left in the steam generators, with no makeup, to remove stored and decay heat for about 16 minutes. Thus, substantial time is available for the operator to manually establish auxiliary or normal feedwater. Also, an analysis provided as part of a power uprating request for the Palisades shows that, if auxiliary feedwater were supplied during the post reactor trip period, primary system pressure would be limited to 2162 psi, thereby avoiding the lifting of the PORV (2400 psi set point).

A similar analysis performed by C-E for Millstone Unit 2 shows that PORV actuation would not occur if auxiliary feedwater was established within 13 minutes. From this it can be seen that these typical C-E plants are much less susceptible than a B&W plant to the failures and subsequent problems that occurred at TMI-2 (see Table 10.)

6.1.2 Westinghouse

The Westinghouse PWRs selected were Indian Point Unit 3 and D.C. Cook Unit 1. Despite some minor differences to the RCS designs, the response of these plants to a loss of feedwater transient is similar. Relevant design data for these plants, which were collected from the plant FSARs and Technical Specifications are given in Table 10.

As was the case for the C-E plants, Table 10 shows that there is a relatively small difference in total reactor coolant system volume between the W plants selected and a typical B&W reactor. Thus, all else being equal, the temperature and pressure rise (fall) in the primary system will be quite similar for a W or B&W plant for a given reduction (increase) in steam generator heat removal capability.

As the table shows, the inventory of water (in terms of minutes to boil-off at full power) on the secondary side of the steam generators is two to three times larger for these W plants than for a B&W plant (although not as large as that for a C-E plant). The substantially larger heat transfer buffer afforded by the larger inventory of water in a Westinghouse steam generator results in a slower pressure and temperature rise in the primary system whenever normal feedwater supply is lost. However, the rate of rise of pressure and temperature would be expected to be somewhat faster than that for a C-E plant that has an even larger steam generator water inventory. As for the C-E plants, the reviewed Westinghouse plants incorporate an anticipatory reactor trip that, on low steam generator water level, will cause termination of the pressure and temperature rise in the primary system before an excessive loss of steam generator heat removal capability can occur.

The margin between normal reactor coolant system operating pressure and the lift setting for the PORV is 100 psi. This is also somewhat higher than the 70 psi margin for a B&W plant although it is not as large as the 150 psi margin for the C-E plants considered.

For these Westinghouse plants, the auxiliary pumps start automatically on several conditions, including low steam generator water level or trip of the main feed pumps. FSARs state that the auxiliary feed pumps will maintain sufficient heat transfer through the steam generators during the transient to prevent actuation of the PORVs. Thus, the susceptibility of Westinghouse plants to lifting the PORV is less than for a B&W plant.

Although the analyses assure automatic actuation of auxiliary feedwater supply, its availability would not be necessary to prevent PORV actuation during the initial heatup phase. Auxiliary feedwater supply is necessary to preclude subsequent lifting of the PORV after reactor trip when decay and stored heat must be removed. The larger steam generator inventory of these W plants would result in a significantly longer period of time before auxiliary feedwater would be required to prevent lifting the PORV after reactor trip. A review of actual loss of feedwater transients that have occurred at operating W plants confirms these transient characteristics for other W reactors.

From the preceding discussion, it can be seen that these typical W plants are also less susceptible than a B&W plant to the failures and subsequent problems that occurred at TMI-2 on March 28, 1979 (see Table 11.)

TABLE 11 SUSCEPTIBILITY TO PORV VALVE LIFT FOR B&W, C-E, AND W PWRs AS A RESULT OF A LOSS OF FEEDWATER EVENT

Susceptibility to PORV Valve Lift*

NSSS	Before Reactor Trip		After Reactor Trip	
Supplier	Aux. Feed	No Aux. Feed	Aux. Feed Immediately	Aux. Feed after 10. min.
B&W	Very high	Very high	Low	Very high
C-E	Very low	Very low	Very low	Low
W	Very low	Very low	Very low	Low

*These findings are subject to reconsideration following licensee actions in response to IE Bulletin 79-05A and shutdown of the B&W plants.

7.0 INSPECTION AND ENFORCEMENT BULLETINS (TMI-2)

7.1 General

The NRC has a formal program within the Office of Inspection and Enforcement (IE) to feed back information to all licensees regarding events of safety significance at operating reactors. When an event at an individual plant is of such safety significance as to require action by other licensees, an IE Bulletin is issued.

As a result of the TMI-2 accident, a number of IE Bulletins were issued. A listing of the bulletins that have been issued to date is provided in Table 12. These bulletins are provided for reference in Appendix X.

The followup actions required of the licensees in response to these bulletins can be separated into two categories: (a) those that required reviews of information provided in the bulletins and assessments by the licensees as to the need for changes at the plants; and (b) those that required implementation of changes to specific design features or operating procedures at the plants. Each of these categories of actions is discussed separately in the following sections. A summary of NRC evaluation to date of the actions taken by the licensees in response to the bulletins is provided in Section 7.3.

7.2 Actions Required by IE Bulletins

7.2.1 Review Actions

IE Bulletin 79-05 was the first bulletin issued in connection with the Three Mile Island accident. The bulletin was issued on April 1, 1979, and provided a description of the initiating events and the subsequent course of the incident.

The primary focus of IE Bulletin 79-05 was to provide information to all licensees and to initiate a review by B&W plant licensees of the need for changes at their plants. The later bulletins (i.e., 79-05A, 79-05B, 79-06, 79-06A, 79-06B, and 79-08) initiated similar reviews by all the licensees and identified more specific corrective measures to be taken. The following is a listing of the general review actions required by the bulletins. Actions required by the bulletins that involve specific changes to the plant design or operating procedures are discussed in Section 7.2.2.

1. Review operating procedures to assure that they acknowledge the possibility of forming voids in the primary coolant system large enough to compromise core cooling, and that they identify (a) the operator actions required to prevent

TABLE 12 LISTING OF IE BULLETINS FOR THREE MILE ISLAND ACCIDENT

Bulletin	Subject	Issue Date	Issued to Licensees
79-05	Nuclear Incident at Three Mile Island	4/1/79	All B&W power reactors with an OL for action and all other power reactors for information
79-05A	Nuclear Incident at Three Mile Island - Supplement	4/5/79	All B&W power reactors with an OL for action and all other power reactors for information
79-06	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident	4/11/79	All PWR power reactors with an OL except B&W for action and all other power reactors for information
79-06A	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident	4/14/79	All Westinghouse power reactors with an OL for action and all other power reactors for information
79-06B	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident	4/14/79	All C-E power reactors with an OL for action and all other power reactors for information
79-08	Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident	4/14/79	All B&W power reactors with an OL for action and all other power reactors for information
79-06A (Rev. 1)	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident	4/18/79	All Westinghouse power reactors with an OL for action and all other power reactors for information
79-05B	Nuclear Incident at Three Mile Island	4/21/79	All B&W power reactors with an OL for action and all other power reactors for information

the formation of such voids, and (b) the operator actions required to ensure continued core cooling in the event voids are formed.

2. Review operating procedures and training instructions to assure that operators do not override automatic actions of engineered safety features without sufficient cause for doing so.

3. Review all safety-related valve positions and procedures for positioning valves following maintenance and testing to assure that they are and will continue to be in the correct position.

4. Review the operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the containment to assure that the transfer will not occur inadvertently.

5. Review reporting procedures for serious events to assure prompt notification of the NRC.

6. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

In addition to the above requests for reviews by all the reactor licensees, B&W plant licensees were specifically requested to review any transients that had occurred in the past that were similar to the Three Mile Island events and report any significant deviations from expected performance along with a safety analysis and a description of any corrective actions taken.

Also in connection with the bulletins, the following two requests for information were submitted to licensees with boiling water power reactors:

1. Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., reactor core isolation cooling) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

2. Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have available to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems.

7.2.2 Changes to Plant Design Features and Operating Procedures

In the days immediately following the issuance of IE Bulletin 79-05, the NRC received additional preliminary information that allowed it to identify six potential human, design, and mechanical failures that had resulted in the core damage and radiation releases at Three Mile Island. To assure that all the licensees were fully informed of these factors, a series of followup bulletins was issued beginning with IE Bulletin 79-05A on April 5, 1979.

In contrast to IE Bulletin 79-05, these later bulletins not only provided information for the licensees to review but also identified specific action to be taken to lessen the likelihood of a repeat of the events at Three Mile Island. The following is a listing of the most significant types of actions to be taken:

1. The specific conditions under which the automatically initiated high-pressure injection (HPI) system should not be overridden by the operators were specified and the licensees were required to modify existing operating procedures and training instructions accordingly.

2. The licensees were required to modify existing operating procedures if necessary to assure that (a) at least a minimum specified number of RCPs would remain operating in the event of an HPI initiation with reactor coolant pumps running, and (b) the operators would not rely solely upon pressurizer level indication alone without considering other plant parameters in evaluating plant conditions such as water inventory in the reactor primary system.

3. Specific actions with regard to containment isolation system design features and procedures to prevent the release of radioactivity from the containment were required.

4. Specific actions to improve the availability of auxiliary feedwater systems were required.

5. The licensees were required to modify maintenance and test procedures as necessary to require specific actions that would assure no removal of redundant safety systems from service as a result of testing or maintenance.

6. The licensees were required to modify reporting procedures for prompt NRC notification to assure that the NRC is notified within one hour of the time that a reactor is not in a controlled or expected condition of operation. Further, at that time, an open continuous communication channel with the NRC was required to be established and maintained.

7. Licensees with B&W plants were required to provide for NRC approval a design review and schedule for implementation of a safety grade automatic anticipatory reactor trip for loss of feedwater, turbine trip, or significant reduction in steam generator level.

8. Licensees with B&W plants were required to provide an analysis and propose modifications to design features and operating procedures to assure a reduction in the likelihood of automatic actuation of the pressurizer power-operated relief valve during anticipated transients.

9. Licensees with B&W plants were required to provide procedures and training to operating personnel for a prompt manual trip of the reactor for transients that result in a pressure increase in the reactor coolant system.

10. Licensees with B&W plants were required to develop procedures and train operating personnel on methods of establishing and maintaining natural circulation. Specific precautions to be included in the instructions were specified.

11. Licensees with B&W plants were required to implement procedures immediately that assure that two 100 percent independent steam generator auxiliary feedwater flow paths remain available or the reactor be shut down within a specified period of time.

12. Licensees with plants with pressurizer power-operated relief valves were required to prepare and implement immediately specific procedures identified to assure that the operators would be aware of a stuck-open valve and would take action to secure it at pressures below the set point.

13. Licensees with plants that use pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system were required to trip the low pressurizer level set point bistables such that, when the pressurizer pressure reaches the low set point, safety injection would be initiated regardless of the pressurizer level. In addition, operators were instructed to manually initiate safety injection when the pressurizer pressure indication reached the actuation set point whether or not the level indication had dropped to the actuation set point.

14. Licensees with plants where the auxiliary feedwater system is not automatically initiated were instructed to prepare and implement procedures immediately that require the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate adequate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which can be limited by such action.

7.3 Evaluation of Licensee Responses to IE Bulletins

The NRC staff evaluation of all of the licensee responses to the Three Mile Island IE Bulletins is still ongoing. To date, the major NRC effort has been directed towards completing the review of responses by B&W plant licensees to IE Bulletin 79-05A, and this review is now complete. IE Bulletin 79-05A contains all of the main points relevant to B&W plants identified in Section 7.2 with the exception of those dealing with natural circulation and measures to reduce the likelihood of actuating a power-operated relief valve during anticipated operational occurrences. These two exceptions were a part of IE Bulletin 79-05B and are still under review.

A separate safety evaluation report has been prepared for each B&W plant licensee's response to IE Bulletin 79-05A. These reports state that, although certain areas have been identified in which additional information and clarification is needed, the licensees have correctly interpreted IE Bulletin 79-05A and demonstrated their understanding of the salient concerns arising from the Three Mile Island incident in reviewing the implications on their own operations, and have provided added assurance for the protection of the public health and safety during plant operation. On this basis, the staff believes that the principal objective of IE Bulletin 79-05A has been satisfied. Future staff efforts in connection with the bulletins will be directed toward reviewing the B&W plant licensees' responses to IE Bulletin 79-05B and the other licensees' responses to the other bulletins.

8.0 GENERAL CONCLUSION - FINDINGS AND RECOMMENDATIONS

8.1 General Conclusion

Findings and recommendations are presented for consideration and action by the reactor vendors, licensees, and the NRC based on the results of the review performed by the task group. The task group evaluated the generic aspects of feedwater transients for B&W plants in the light of operating experience including the TMI-2 accident. Design features, operational aspects, and the licensing basis are the principal areas reviewed by the task group and discussed in this report.

As stated, the purpose of this report was to make an early assessment concerning those measures that might be necessary to prevent a recurrence of the TMI-2 event at other B&W facilities; however, the results of this short-term review indicated that many of the findings and recommendations are also applicable to the other PWR vendors (i.e., Westinghouse and Combustion Engineering) and, in certain cases, are appropriate actions for the BWR plants designed by the General Electric Company (e.g., in the areas of training and analyses). Many actions have been taken since the TMI-2 event by the staff and industry to ensure that recurrence would not take place, including the shutdown of the B&W facilities for short-term corrective actions. It is also realized that there are ongoing activities to further improve the safety margins in these plants as this report is being published. Thus, this report is to be treated as a status report on those matters related to the feedwater transient aspects that were identified in the initial period after March 28, 1979, and is not to be considered a complete and final set of recommended actions. It is quite certain that other actions will be required as the overall review of the TMI-2 accident progresses.

On the basis of the results of this interim review, the general conclusion can be reached that certain design improvements and other actions already being implemented on B&W are necessary before plant operation is resumed. These actions will be specified in shutdown orders that resulted to varying degree from this generic review; e.g., reactor trip on secondary side of the plant, operator training, auxiliary feedwater reliability, and the need for further analyses of small break loss-of-coolant accidents. In addition, the staff find that longer term improvements are required with regard to training and actions, equipment reliability, and the evaluation of transients and small break LOCAs. The staff believes implementation of the recommendations stated in this report would further increase the safety margins in the B&W PWR plants.

8.2 Plant Design

8.2.1 Plant Comparisons

Finding

A preliminary comparison of plant design features shows similarity among the currently licensed B&W reactors. Given the sequence of events that occurred at TMI-2, the task group finds no basic design deficiency alone that would have precluded the occurrence of similar degraded conditions in the other B&W plants without the equipment malfunctions and human errors involved in the TMI-2 sequence of events.

There are locations in the primary system where steam or other gases can accumulate if the primary system is permitted to depressurize to saturation conditions. These locations are in the upper reactor vessel, in the region of each reactor coolant pump, and in the upper levels of the hot legs and steam generators. There appears to be no specific reason for voids to accumulate only in the pressurizer under these conditions, although during normal operation only the pressurizer is operated at saturation conditions.

Recommendations

Various anticipated transient events with the potential for depressurization and flashing in the primary system should be evaluated generically with special attention directed to understanding the sensitivity of their consequences as a function of equipment malfunction or human error. Methods for improving the likelihood of success in dealing with such transients should be investigated by the NRC and B&W. These include (a) actions already under way for B&W plants following the bulletins and the confirming shutdown orders (e.g., operating procedures and plant instrumentation); (b) development of improved instrumentation to indicate subcooling in the primary system so that a more reliable indication of water level in the reactor vessel would be provided to the operators (see Section 8.2.7); (c) improvement of automatic actions of protection system, engineered safety features, and other safety-related equipment to decrease the dependence on operator actions especially during the early part of the transient; and (d) a basic study of the B&W plant design with regard to interaction between the OSTG, ICS and the sizing of the pressurizer/surge line.

Consideration should be given to means that would limit the pressure achieved during refill to remove operator concern about overpressure potential from HPI when core cooling is required.

8.2.2 Steam Generator and Feedwater Systems

Finding

Only the bypass controls for demineralizers were compared in detail, but this area alone indicates some variation in potential for loss of feedwater events among the B&W plants. There are, however, other initiations due to human error or equipment failure that would lead to a loss of feedwater transient. The B&W once-through steam generators have much smaller water inventories than those associated with Combustion Engineering and Westinghouse plants. As a result, the B&W steam generators boil off on loss of feedwater much more quickly. This leads to a more rapid increase in primary pressure on loss of main feedwater in B&W plants and therefore requires greater performance and reliability of the AFW delivery.

The auxiliary feedwater system tends to limit the overpressure excursion by providing some continuation of heat rejection capability to the steam generators. Actions given in IE Bulletin 79-05B should prevent subsequent overpressure and reduce the loss of primary system inventory through the PORV and permit the HPI to refill and depressurize the primary system more quickly.

Recommendations

Once-Through Steam Generator (OTSG)

The safety aspects of the OTSG for B&W plants should be defined and included in operating procedures that deal with transients and small break LOCAs. Included should be the results of a sensitivity study of the water inventory and time for boiloff to consider the potential benefit of increasing the operating water level in OTSGs for B&W plants.

Main Feedwater Systems

Feedwater transients have been initiated from a variety of human and equipment failures. Although some improvements can and should be made to feedwater system reliability and to identify and correct design deficiencies, the occurrence of feedwater transients cannot be eliminated. Thus, the emphasis should be on coping and mitigating the consequences of feedwater transients.

Auxiliary (Emergency) Feedwater Systems

Goals should be established by NRC and means developed to make the auxiliary feedwater system more reliable. Short-term action is required by the recent shutdown orders and IE bulletins and should be followed by a longer term reevaluation of system reliability and interactions. Increased surveillance should be considered for all PWR plants.

8.2.3 Plant Control Systems

Finding

The design requirements and criteria for plant process controls are not well defined in NRC regulations. Furthermore, the interaction of these features, especially in the B&W integrated control system and the auxiliary feedwater system, have not been thoroughly explored in previous NRC licensing reviews. The plant control systems play an essential part in plant operations and the control of transient situations that would otherwise introduce challenges to the plant safety system.

Failure of controls could initiate a transient or could inhibit the control of a transient otherwise mitigated.

Recommendation

1. The role of control systems in all plants, and their significance to safety, should be reevaluated by NRC and the vendors. The evaluations should be performed by the industry with guidelines developed by the NRC. Consideration should be given to establishing criteria regarding the rate at which transients challenge the plant safety systems. Such transients should include (a) those initiated by control failure plus (b) those initiated outside the control system that are not successfully mitigated by the control system. The plant monitoring instrumentation should be included in this evaluation. Failure mode and effects should be utilized to identify realistic plant interactions resulting from failures in non-safety systems, safety systems, and operator actions.

2. As a result of the TMI-2 accident, the evaluation of monitoring systems should focus extra attention on certain specific monitoring systems, such as the pressurizer level indication discussed in Section 2.2.9 of this report. The pressurizer level indicator has been used, sometimes incorrectly as at TMI-2, as a direct indicator of the adequacy of water inventory in the reactor vessel. A more direct and more easily interpreted indication of water inventory in the primary system would make operator inference and actions more reliable. Alternate monitoring methods for evaluating adequacy of reactor vessel water level, such as the primary inventory control system discussed in Section 2.2.9, should also be evaluated in the recommended study. Specifically, one approach can be characterized as instrumentation to measure and directly display to the operator such derived quantities as the subcooling in the reactor outlet, or the quantity of and energy content of cooling water in the core. Also, an assessment of the balance between additional automation versus improved operator response to maintain adequate plant conditions should be made.

3. Criteria should be defined and established by NRC for equipment and systems that are important to safe plant operation but are not required to be Class 1E. This effort would follow the completion of the evaluations described in Items 1 and 2 above. Although the need for "Class 2E" classification of equipment has been recognized by the staff, the industry, and standards organizations, appropriate standards have not yet been developed.

8.2.4 Power-Operated Relief Valve

Finding

All B&W plants except for Davis-Besse 1 have Dresser power-operated relief valves (several different models). Davis-Besse 1 has a Crosby Model HPN-SN valve. Failures have occurred on both the Dresser and Crosby valves and improvements have been made in the valves and their controls. At the moment, the staff has no basis for rating one better than the other.

As related to the TMI-2 accident, the failure of the PORV to close changed a loss-of-feedwater transient into a small loss-of-coolant accident. This was not immediately apparent to the operators. The effects of two-phase flow have not yet been fully evaluated.

Interim measures have been taken to reduce the number of times the PORV would be required to operate during the life of a plant by IE Bulletin 79-05B and the shutdown provisions that include (a) installation of an anticipatory reactor trip or turbine trip, (b) improving the reliability of the auxiliary feedwater, (c) lowering the reactor trip pressure set point, and (d) raising the set points for the PORV. Other actions may be necessary before subsequent start-up of the B&W plants.

Recommendation

A more direct and positive indication of valve position is needed. Consideration also should be given to the merits of upgrading valves and the associated control and power equipment to safety grade, thereby achieving greater valve reliability; or, as an alternate, consideration should be given to the merits of closing the relief and block valves during power operation. In addition, an evaluation and possible testing of the PORV with regard to two-phase flow conditions should be made. These actions should be taken by NRC and B&W.

8.2.5 Data From Operating Plants

Finding

A review of the LERs dealing with feedwater types of transients has indicated that three events have occurred in B&W plants in which a power-operated relief valve (PORV) stuck open during the event. There have been about 150 occasions in which the pressurizer relief valves have actuated yielding about an arrival rate of 2×10^{-2} per event and a probability of a small break LOCA of about 0.1 per reactor year, which is excessive. This is an example of the type of information that can be derived from a study of experiences in operating plants to identify those equipment malfunctions and/or events that lead to situations of significant frequency that challenge the plant safety features.

Recommendation

A study should be made by NRC of the entire reporting and data-assembly processes followed to accumulate and assess the significance of operating plant data. In particular, means should be developed to identify events of such recurring frequency that they merit prompt attention by NRC; i.e., those that frequently challenge the plant safety systems.

8.2.6 Containment Isolation System

Finding

The experience gained from the TMI-2 accident indicates that automatic containment isolation was not initiated by safety injection actuation. This led to a significant release of contaminated liquids from the containment to the auxiliary building where an overflow occurred.

Recommendation

1. Requirements should be revised by NRC to reflect the importance to safety of isolating all nonessential lines penetrating the containment in the event of an accident. Nonessential lines are those lines that, upon isolation, do not degrade core cooling capability and do not have a post-accident safety function; e.g., sump lines.

2. Administrative procedures should be strengthened to ensure the correct positioning of all manual and remote manual containment isolation valves under administrative control.

3. The plant parameters to be monitored for the initiation of containment isolation should be evaluated by NRC; e.g., containment pressure, containment

radiation level, and those parameters relied on to initiate safety injection cooling of the reactor core. The parameters sensed for the safety injection signal should be evaluated in terms of their validity and reliability for use in initiating containment isolation.

4. Systems that are capable of transfer of potentially radioactive liquids and gases out of the containment should be identified; and the containment isolation system, including operating modes and procedures, should be evaluated to assure that inadvertent transfer of fluids will not occur. In this regard, the automatic actuation of these systems does not appear to be desirable, and interlocks may be required to prevent an automatic transfer from occurring when a high radiation level exists.

5. The impact on containment isolation system performance of resetting engineered safety features actuation signals following an accident should be evaluated for all plants.

8.2.7 Residual Heat Removal System

Finding

For reasons not yet understood, the low-pressure heat removal system was not placed into operation during the early (first 12 hours) stages of the accident. The operators attempted to reduce system pressure after approximately 7 1/2 hours (see Figure 2); however, the pressure never was low enough to cut-in the residual heat removal (RHR) system (about 300 psig). Subsequent long-term heat removal by the RHR was not carried out because of the high levels of contamination in the reactor coolant system water and an apparent question of the leak tightness of the RHR system outside of the containment.

Recommendation

The NRC, licensees, and designers should reexamine the design basis and adequacy of the RHR system in the light of the TMI-2 experience in which the reactor coolant system became highly contaminated due to significant core damage. This should include access capability and location of equipment for the operator.

8.2.8 Design Features to Improve Operator Response

Finding

The number and complexity of possible event sequences for nuclear power reactors make it impossible to assure that operators are specifically trained to respond correctly to each and every off-normal or accident condition.

Significant core damage at TMI-2 would not have occurred only because of the loss of main feedwater, late initiation of auxiliary feedwater, or the occurrence of a stuck-open relief valve. It probably could have been averted even with all three. Significant core damage occurred because primary system conditions were permitted to degrade by overriding an automatic HPI safety system resulting from an indication of pressurizer water level rather than more direct knowledge of the water inventory in the reactor vessel.

NRC preliminary review of the chronology of events during the TMI-2 accident has revealed that several deliberate operator actions may have contributed to the severity of the accident and that several opportunities for action to intervene productively in the progression of events were not recognized. The staff believes that the deficiency in operator action at various points in the accident sequence was at least partially the result of the inability to diagnose the situation in a real time frame and the inability to assess or predict confidently the effects of remedial actions before they were taken. It appears that the operators were following existing operating procedures for the type of event believed to have occurred.

Recommendation

An overriding priority for plant conditions to be pursued following a transient or accident must be established so that, regardless of other concerns, no actions on the part of the operator or automatic systems should be contrary to maintaining core cooling.

The condition to be pursued is a full primary system inventory, full primary system pressure, and maximum subcooling. This condition should be pursued by knowledgable operator response and supported by the safety system design, control system design, Technical Specifications, and operating procedures. Should other considerations place a limit on pursuing such a course, automatic safety actions should be provided to satisfy those secondary concerns within the limits of retaining a coolable core.

There will always be a residuum of possible but not postulated and analyzed situations. To address this, and as an attempt to extend the defense-in-depth concept, the NRC staff should study ways to make the operator a more effective recovery agent or incident/accident mitigator. Such a study should look for ways to (a) prevent (inhibit) inappropriate actions and (b) promote productive intervention. An element of the study that could serve both purposes would be an investigation of ways to furnish the operator with correct, current, digestible information regarding principal plant conditions (processes, systems, equipment). The means whereby the operator would best employ this information should also be considered; e.g., on-line real-time analysis. The work in this area at the Halden reactor in Norway on disturbance analyses could provide a useful point of departure for this study.

8.3 Operations

8.3.1 Training

Finding

Operator training programs have evolved over the last 10 to 15 years from a concentrated on-the-job training, with little time allotted to formal training, or to the present structured, formal, NRC-approved programs.

The staff believes that training simulators have had a significant effect on the quality of operator training since they permit the operator to experience abnormal and emergency events. The NRC has conducted examinations utilizing simulators for about 4 to 5 years and finds that this examination is much more demanding on the person being examined (as well as the examiner) than a normal "walk-through" dialogue. Consequently, a better evaluation of an individual's competency can be made using a simulator; however, the extent of the improvement in evaluation potential in each case will depend on the degree of similarity between the simulation and the plant that the individual will operate.

Training programs have underemphasized the possibility of failures in various systems, nonstandard passive conditions (misaligned systems), possible failure of engineered safeguard equipment when called upon, and even the effects of multiple failures. While the merits of the single failure criterion may be significant as a design basis, it is not clear that it should be considered as a limiting basis for training purposes. Training aspects include the technical staff.

Recommendations

1. Simulator training programs should be reviewed by NRC and the vendors as to scope and content to assure that they address human errors such as those that contributed to the TMI-2 accident and should also incorporate training to respond to multiple failures and safety system malfunctions. All simulator training programs should include drills on the following:

   a. Natural circulation to the time of cold shutdown
   b. ECCS actuation failures with programmed malfunctions

2. Simulator models should be modified by the PWR vendors to include flashing, single failure of various system, the effects of multiple failures, and ECCS malfunctions.

3. Ways should be studied by NRC that would better evaluate a senior operator's ability to direct activities during abnormal or emergency operations.

4. Training on protecting the core should be emphasized at all plants. This includes providing means to recognize whether an adequate heat sink, primary system inventory, and intact primary and secondary systems exist.

5. Refresher training on emergency procedures should be increased. The technical staff should also be included with this activity. Requalification programs should require simulator training; criteria should be developed in this regard. Emphasis in requalification programs should be placed on evaluating operator and senior operator response during abnormal and emergency conditions.

8.3.2 Operating Procedures

Findings

Operating and emergency procedures are developed in accordance with Regulatory Guide 1.33, Appendix A, Quality Assurance Program Requirements (Operation) and Sections 5.3.2 and 5.3.9 of ANSI 18/ANS 3.2, entitled "Administrative Controls and Quality Assurance for Operation of Nuclear Power Plants."

Normal operating procedures involve the use of checklists and function as controlled evaluations with final conditions as the goals to achieve. Abnormal and emergency procedures are completely different. When abnormal or emergency conditions occur, the operator is working with automatic responses and may have to take manual actions.

Recommendations

Emergency procedures should be written in real time as an aid for the operator to study and memorize. The procedures should be developed in conjunction with simulator studies and results available from analyses to promote proper understanding of the event sequences, margins available to the operator, and critical decision points. Such action may include on-line real-time computers. When real incidents occur, operators must be able to critique themselves and the procedures used after stable conditions have been achieved. This will give credence to the procedures and allow all operators to gain additional knowledge from the event.

Procedures that address single failures as well as the effects of multiple failures should be written to accommodate events similar to those at TMI-2. Examples include (a) complete loss of power, (b) loss of power to ICS on B&W plants, (c) loss of vital instrumentation and power supplies, (d) reactivity anomalies, (e) complete loss of feedwater, and (f) anticipated transients without scram.

Procedures must be readily available for the operator to use; emergency procedures should be indexed for quick retrieval and use.

An additional task should be a review of operating procedures that deal with implementing Technical Specification requirements to ensure that overly restrictive requirements are not established that would inhibit operator improvisation under abnormal conditions; e.g., concerns on system pressurization and pressurizer level as discrete parameters rather than the interrelationship to void formation during a transient or small break LOCA.

8.3.3 Human Factors

Findings

The operator has been trained to rely on his instrumentation. He will continue to do so until he suspects an erroneous reading; however, he must be trained not to rely solely on a single indication since it may be erroneous or misleading under certain conditions.

If the operator has too many additional manual functions to perform, he may reduce his observations on other system parameters, which may lead him to have "tunnel vision." Subject to further understanding, it appears at this time that in the TMI-2 accident the operator apparently kept relying only on the high pressurizer level.

Human factors engineering has not been sufficiently emphasized in the design and layout of the control rooms. The location of instruments and controls in many power plants often increases the likelihood of operator error or, at the least, impedes the operator in efficiently carrying out the normal, abnormal, and emergency actions required of him.

Recommendations

Operator and technical staff training should be revised as necessary to improve the operator's understanding of his responsibilities during abnormal and emergency conditions. The design basis for the plant has provided that, in the event of emergencies, suitable actions will be automatically initiated by the safety systems. The operator's initial responsibility is to monitor the parameters of interest and verify that appropriate safety systems actuations have taken place. If the appropriate actuations have not occurred, the operator must intercede and perform whatever action is necessary to effect them. The entire control board should be monitored and all parameters of concern evaluated. In conjunction with the evaluation, it is recognized that the operator has been trained to believe his instrumentation, but he must not do so blindly. Almost every parameter of interest that is monitored can be validated by appropriate checking of other instrumentation. He must perform this cross-check to verify instrument display and must not develop "tunnel vision" in which one display is relied on exclusively.

Other automatic means of recording events during emergencies must be used. A voice tape recorder should be used to provide a record for the events.

Critiques should be made immediately after any major events have occurred. This should include all recorder charts and alarm printouts. The individuals involved should prepare their reports before leaving the station.

More emphasis on human factors engineering should be placed on the design and layout of control rooms. System identification and location of instruments should be analyzed to improve operator response during an abnormal or emergency operation.

8.4 Licensing Basis and Regulations

8.4.1 Analysis of Feedwater and Other Transients

Finding

The analysis of feedwater and other anticipated operational transients has been found to be somewhat idealized in terms of the TMI-2 accident. The models are simplistic and do not always include provisions to consider single failures and progressively degraded conditions based upon human error and/or equipment malfunction. Even though analyses may not be able to track all events and possible courses, general insight and understanding of the transient and reactor system behavior can be realized from sensitivity studies. Such information would be helpful to the operator by incorporating the essential information into the procedures.

Recommendation

The analysis of feedwater and other anticipated operational transients should be performed by B&W on a more far-ranging as well as a more realistic basis to include interactions of the control systems, consequential failures of equipment not designed to cope with the event, single failures of safety features, and operator actions and/or errors based upon available information on plant parameters and procedures. For example, the availability of a train of the auxiliary feedwater system is presumed in the analysis, which thus does not consider possible failure modes that might preclude its availability. It is also recognized that some equipment availability may or may not be included if the objective of the analyses is to arrive at a bounding condition; e.g., no auxiliary feedwater and neglect of the PORV would lead to a high-pressure condition in the reactor system. However, the failure of a PORV leading to a small event LOCA would be overlooked. In addition, the models should include the capability to predict voiding in the reactor coolant system under dynamic conditions. The effects of a loss of either offsite or onsite power should be explicit in the analyses. The analyses should be extended to the time that stable reactor cooling is assured including the natural circulation cooling mode where appropriate. In addition, sensitivity studies should be performed to clearly define the significance of the steam generator as a heat sink, as to whether it is to be relied upon for all breaks, or that adequate cooling of the reactor can be achieved without the steam generators by way of "bleed-and-feed" in the reactor system using the PORV and HPI system. This should also deal with the question of degraded heat transfer due to the presence of non-condensibles in the systems. The B&W plants should be reanalyzed according to the above in terms of recent B&W shutdown actions. This also applies to the other PWR vendors as well as to BWR vendor where applicable. The results of the sensitivity studies of essential equipment and systems should be evaluated and used for the development of emergency procedures.

8.4.2 Small Break LOCA Analysis

Findings

Small break LOCA events have been extended down to the range of approximately 0.05 ft^2. It was believed that smaller breaks were well within the capability of the available coolant makeup systems and were not limiting. Recent preliminary calculations of the TMI-2 accident performed at Idaho Nuclear Engineering Laboratory (INEL) show evidence that suggests voiding in the coolant system can occur in conjunction with a rising water level in the pressurizer. This is also predicted from new studies performed by the PWR vendors.

The TMI-2 accident indicates that the possible effects on core coolability for smaller breaks are not completely understood. In this regard, the concern deals with such matters as the sensitivity of break location, reliance on the steam generator as a heat sink, the effects of delays in the availability of the auxiliary feedwater system, and long-term cooling using natural circulation. Furthermore, based on the experience gained from the TMI-2 accident, the effects of equipment malfunction and human error have not been studied in sufficient detail.

Recommendation

The B&W plants should be reanalyzed according to the above finding in accordance with the recent B&W shutdown actions. This also applies to the other PWR vendor as well as to BWRs where applicable.

Additional analyses of small breaks should be performed in the very small break range (i.e., less than 0.05 ft^2). The evaluation should include consideration of input assumptions regarding such aspects as the auxiliary feedwater system, offsite and onsite power, equipment operability under accident modes, operator actions based upon available information on plant parameters, and procedures.

The calculational codes should include the capability to predict voiding in the reactor coolant system under dynamic conditions.

The analyses of small breaks should extend to the period during which the plant is being cooled in a stable mode (e.g., cold shutdown) either by natural circulation or other means such as the HPI, and should include other events such as a small break in a main steam line or a steam generator tube rupture. As indicated in Section 8.3.1, the sensitivity of the steam generator as a heat sink needs to be evaluated.

8.4.3 Analysis Codes

Finding

The computer codes generally used for transient and small break LOCA analyses are complex and do not always include provisions for extending the calculations to cover the event duration through the time period until stable cooling (e.g., cold shutdown) is achieved. In some cases, conservative bounding types of assumptions and models are used that may mask out realistic system and equipment behavior. In addition, many of the vendor codes have not been reviewed in detail by the NRC.

Recommendation

B&W should review and modify as appropriate its computer codes to ensure that they can perform full spectrum analyses using realistic models. This action is also recommended for the other PWR vendors. GE should also be subjected to a similar review with regard to the BWR plants. Furthermore, the codes together with their experimental verification should be submitted for review by the NRC. It is expected that such efforts might take several years to complete. In the interim, existing codes should be used but with more realistic input parameters and model assumptions to ensure proper tracking of the events; e.g., using installed equipment and systems as well as associated control systems.

8.4.4 Audit Calculations by NRC

Finding

The NRC presently has only a limited independent capability to perform audit calculations for transients and LOCA events. While reliance has been placed on the results of staff review of licensee calculations, some audit calculations were performed by the staff and by NRC contractors. Efforts are under way to correct this shortcoming, but current LOCA capability is limited to performance of analyses on only portions of the event with reliance placed on hand calculations for the balance of the event. The present staff analysis capability is limited to PWRs with U-tube-type steam generators.

Recommendation

The NRC should expeditiously complete its development of independent capability to perform quick engineering types of calculations for transients and small-break LOCAs. This effort should be coordinated with the research group on a short-term basis. Consideration should also be given to natural circulation cooling in these code development efforts. Audit calculations should be performed for selected transients and for the small break LOCA for representative samples of operating PWRs and BWRs.

8.4.5 Standard Review Plan (SRP)

Finding

The applicable SRPs provide only general guidance for the calculation of feedwater types of transients. Based on the TMI-2 experience, more explicit guidance is necessary. Furthermore, there is insufficient guidance given for the calculation of small breaks. Sensitivity studies and long-term coolability are not included in all sections.

Recommendation

The SRP should be reviewed with regard to the evaluation of transients and small break LOCA based on TMI-2 experience and recent discussions with the PWR vendors. BWR plants should also be considered.

8.4.6 General Design Criteria (GDC)

Finding

The applicable GDC for anticipated transients (e.g., GDC 10, 13, 14, and 15) appear to reasonably encompass the necessary requirements for plant design features. Although the GDC may be adequate, their general nature leads to broad interpretation of specific requirements. The matter of defining a passive failure, as noted in Appendix A to 10 CFR 50, and its application to such failures as the PORV or other valves leads to misunderstanding as to their treatment in transient and accident analyses.

Recommendation

Regulatory Guides should be developed expeditiously to provide greater guidance on design requirements for anticipated transients for interpretation of GDC (e.g., 10, 13, 14, and 15).

In addition, better guidance should be provided for the proper treatment of the failure of a PORV or other valve in transient and accident scenarios with regard to active or passive failures and whether PORV failure should be combined with other failures.

8.4.7 Technical Specifications

Findings

There are Technical Specification requirements that appear to place excessive reliance on single parameters, such as pressurizer level control, and do not include the significance of other parameters that the operator should be considering while making plant adjustments and action decisions. Reporting requirements appear to be too narrowly constrained to violations of Technical Specifications.

Recommendation

Little can be done in the writing of Technical Specifications to ensure compliance. There needs to be serious reexamination of the fundamental regulatory philosophy of reliance on Technical Specifications and the concern of enforcement action to assure safety. However, greater attention can be focused on surveillance and testing requirements to ensure the operability and proper alignment of plant safety systems.

The standard Technical Specifications should be reviewed to ensure that greater attention is paid to plant alignment and safety system operability. A review should be made to ensure that important plant parameters are specified in the Technical Specifications. Consideration should be given to reporting requirements that should include unplanned events that occur in the plant even though they do not result in conditions that exceed existing Technical Specifications.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

APPENDIX A

April 7, 1979

Honorable Joseph M. Hendrie
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555

SUBJECT: INTERIM REPORT ON RECENT ACCIDENT AT THE THREE MILE ISLAND NUCLEAR STATION UNIT 2

Dear Dr. Hendrie

During its 228th meeting, April 5-7, 1979, the Advisory Committee on Reactor Safeguards reviewed the circumstances relating to the recent accident at the Three Mile Island Nuclear Station Unit 2. During this review, the Committee had the benefit of discussions with the NRC Staff.

Our study of the accident at Three Mile Island has shown that it is very difficult for a PWR plant operator to understand and properly control the course of an accident involving a small break in the reactor coolant system accompanied by other abnormal conditions.

The Committee recommends that further analyses be made, as soon as possible, of transients and accidents in PWRs that involve initially, or at some time during their course, a small break in the primary system. The computer codes used for these analyses should be capable of predicting the conditions observed during the accident at Three Mile Island, including thermal-hydraulic effects and clad and fuel temperatures. The range of break sizes considered should include the smallest that could be deemed significant, and should consider a range of break locations.

The Committee believes that the analyses recommended above will demonstrate, as has the accident at Three Mile Island, that additional information regarding the status of the system will be needed in order for the plant operator to follow the course of an accident and thus be able to respond in an appropriate manner. As a minimum, and in the interim, it would be prudent to consider expeditiously the provision of instrumentation that will provide an unambiguous indication of the level of fluid in the reactor vessel. Early consideration should be given also to providing remotely controlled means for venting high points in the reactor system, as practical.

The foregoing recommendations apply to all pressurized water reactors.

The recommendations in IE Bulletin 79-05A, dated April 5, 1979, are believed to be generally suitable for Babcock and Wilcox facilities, on an interim basis. However, the Committee believes that the actions listed in Item 4b. under the heading, "Actions To Be Taken by Licensees," may prove to be unduly prescriptive in view of the uncertainties in predicting the course of anomalous transients or accidents involving small breaks in the primary system.

With regard to Three Mile Island Unit 2, the Committee believes that decisions should be made expeditiously with regard to contingency measures which may be prudent concerning containment and reactor cooldown as a backup to the currently planned cooldown procedure.

The Committee is continuing its review of these and other concerns arising from this accident and will provide further advice as it is developed.

Sincerely,

Max W. Carbon

Max W. Carbon
Chairman

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

APPENDIX B

April 18, 1979

MEMORANDUM FOR: Chairman Hendrie
Commissioner Gilinsky
Commissioner Kennedy
Commissioner Bradford
Commissioner Ahearne

FROM: R. F. Fraley, Executive Director
Advisory Committee on Reactor Safeguards

Attached for your information and use is a copy of the recommendations of the Advisory Committee on Reactor Safeguards which were orally presented to and discussed with you on April 17, 1979 regarding the recent accident at the Three Mile Island Nuclear Station Unit 2.

R F Fraley
R. F. Fraley
Executive Director

Attachment:
Recommendations of the NRC Advisory Committee on Reactor Safeguards Re. the 3/28/79 Accident at The Three Mile Island Nuclear Station Unit 2

April 17, 1979

RECOMMENDATIONS OF THE NUCLEAR REGULATORY COMMISSION ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REGARDING THE MARCH 28, 1979 ACCIDENT AT THE THREE MILE ISLAND NUCLEAR STATION UNIT 2

Presented orally to, and discussed with, the NRC Commissioners during the ACRS-Commissioners Meeting on April 17, 1979 - Washington, D. C.

Natural circulation is an important mode of reactor cooling, both as a planned process and as a process that may be used under abnormal circumstances. The Committee believes that greater understanding of this mode of cooling is required and that detailed analyses should be developed by licensees or their suppliers. The analyses should be supported, as necessary, by experiment. Procedures should be developed for initiating natural circulation in a safe manner and for providing the operator with assurance that circulation has, in fact, been established. This may require installation of instrumentation to measure or indicate flow at low water velocity.

The use of natural circulation for decay heat removal following a loss of offsite power sources requires the maintenance of a suitable overpressure on the reactor coolant system. This overpressure may be assured by placing the pressurizer heaters on a qualified onsite power source with a suitable arrangement of heaters and power distribution to provide redundant capability. Presently operating PWR plants should be surveyed expeditiously to determine whether such arrangements can be provided to assure this aspect of natural circulation capability.

The plant operator should be adequately informed at all times concerning the conditions of reactor coolant system operation which might affect the capability to place the system in the natural circulation mode of operation or to sustain such a mode. Of particular importance is that information which might indicate that the reactor coolant system is approaching the saturation pressure corresponding to the core exit temperature. This impending loss of system overpressure will signal to the operator a possible loss of natural circulation capability. Such a warning may be derived from pressurizer pressure instruments and hot leg temperatures in conjunction with conventional steam tables. A suitable display of this information should be provided to the plant operator at all times. In addition, consideration should be given to the use of the flow exit temperatures from the fuel subassemblies, where available, as an additional indication of natural circulation.

The exit temperature of coolant from the core is currently measured by thermocouples in many PWRs to determine core performance. The Committee recommends that these temperature measurements, as currently available, be used to guide the operator concerning core status. The range of the information displayed and recorded should include the full capability of the thermocouples. It is also recommended that other existing instrumentation be examined for its possible use in assisting operating action during a transient.

The ACRS recommends that operating power reactors be given priority with regard to the definition and implementation of instrumentation which provides additional information to help diagnose and follow the course of a serious accident. This should include improved sampling procedures under accident conditions and techniques to help provide improved guidance to offsite authorities, should this be needed. The Committee recommends that a phased implementation approach be employed so that techniques can be adopted shortly after they are judged to be appropriate.

The ACRS recommends that a high priority be placed on the development and implementation of safety research on the behavior of light water reactors during anomalous transients. The NRC may find it appropriate to develop a capability to simulate a wide range of postulated transient and accident conditions in order to gain increased insight into measures which can be taken to improve reactor safety. The ACRS wishes to reiterate its previous recommendations that a high priority be given to research to improve reactor safety.

Consideration should be given to the desirability of additional equipment status monitoring on various engineered safeguards features and their supporting services to help assure their availability at all times.

The ACRS is continuing its review of the implications of this accident and hope to provide further advice as it is developed.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

APPENDIX C

April 20, 1979

Honorable Victor Gilinsky
Acting Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Dr. Gilinsky:

This letter is in response to yours of April 18, 1979 which requested that the ACRS notify the Commissioners immediately if we believe any of our oral recommendations of April 17 should be acted upon before our next regularly scheduled meeting at which we could prepare a formal letter. The Committee discussed this topic by conference telephone call on April 19 and offers the following comments.

All of the recommendations made by the ACRS in its meeting with the Commissioners on April 17, 1979, are generic in nature and apply to all PWRs. None were intended to require immediate changes in operating procedures or plant modifications of operating PWRs. Such changes should be made only after study of their effects on overall safety. Such studies should be made by the licensees and their suppliers or consultants and by the NRC Staff. The Committee believes that these studies should be begun in the near future on a time scale that will not divert the NRC Staff or the industry representatives from their tasks relating to the cooldown of Three Mile Island Unit 2. However, the Committee believes that it would be possible and desirable to initiate immediately a survey of operating procedures for achieving natural circulation, including the case when offsite power is lost, and the role of the pressurizer heaters in such procedures.

At its meeting on April 16 and 17, 1979, the Committee discussed with the NRC Staff the matter of natural circulation for the Three Mile Island Unit 2 plant. The Committee believes that this matter is receiving careful attention by the NRC Staff and the licensee.

The Committee's own recommendations to the Commission on April 17 were not intended to apply to Three Mile Island Unit 2.

We plan to write a further report on these matters at our May 10, 1979 meeting.

Sincerely,

Max W. Carbon
Chairman

April 26, 1979

DUKE POWER COMPANY

APPENDIX D

POWER BUILDING
422 SOUTH CHURCH STREET, CHARLOTTE, N. C. 28242

US NRC
DISTRIBUTION SERVICES
BRANCH

1979 APR 27 AM 9 04

Mr. Harold R. Denton
Director
Office of Nuclear Reactor Regulation
USNRC
Washington, DC 20555

Re: OCONEE NUCLEAR STATION
DOCKET NOS. 50-269, 50-270 and 50-287

Dear Mr. Denton,

Supplementing my letter of April 25, 1979 and providing additional information responsive to Staff safety concerns identified as items a. through e. on page 1-7 of the ONRR Status Report to the Commission of April 25, 1979, Duke Power Company proposes following actions:

a. Install automatic starting of the interconnected emergency feedwater system so that all three pumps will receive a start signal from any affected unit, and test the system for stability.

b. Develop and implement operating procedures for initiating and controlling emergency feedwater independent of ICS control.

c. Implement a hard-wired control-grade reactor trip on loss of main feedwater and/or turbine trip.

d. Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

e. Station in the control room an additional full-time SRO (or previously licensed SRO with TMI training) for each operating unit to assist with guidance and possible manual action in case of transients until items a. through d. are completed.

7904270 406

Oconee Unit 3 will be shutdown on April 28, 1979, in advance of its annual refueling, and will not be restarted until item a. through d. are completed.

Another Oconee unit will be shutdown on May 12, 1979 if item a. through d. have not been previously accomplished and will remain shutdown until completion of items a. through d.

The remaining Oconee unit will be shutdown on May 19, 1979 if item a. through d. have not been previously accomplished and will remain shutdown until completion of items a. through d.

The sequential shutdown of the 3 units is most important for a number of reasons. As a safety consideration, with one unit in a shutdown mode its emergency feedwater capability is available for use by the other units with no requirement on its own unit. Each emergency feedwater pump is sized for 150% of its unit's requirements. We also need to arrange for hard-to-get fuel oil (which Duke seldom uses and has no allocation for this contingency) which may be necessary to operate combustion turbines to replace Oconee generation. With one very large generator and a number of others now in forced outage, sequential shutdown will reduce the potential for involuntarily interrupting power supply to the public.

Duke further commits to additional improvements in assuring safety related to items a. through e. the same Staff report as follows:

a. For even greater assurance of emergency feedwater supply, we are proceeding with two motor driven pumps for each Oconee unit as more particularly described as Part III in W. O. Parker's letter to you of yesterday. We will be submitting this system concept and analyses to your Staff for review.

b. The failure mode and effects analysis of ICS is underway with high priority by B&W and will be submitted as soon as practicable.

c. These trips will be revised to safety grade.

d. A more complete description of the transient analyses is provided in the attached entitled "Guidelines for the Development of Operational Procedures for Safe Management of Small Breaks in the Reactor Coolant System Pressure Boundary."

e. We will continue operator training and drilling of response procedures as a part of our ongoing program to assure the high state of readiness described by the I&E staff to the Commission yesterday.

We are confident that these steps will meet your Staff concerns and provide additional assurance of public safety.

Sincerely,

W S Lee

W. S. Lee
President

April 26, 1979

GUIDELINES FOR THE DEVELOPMENT OF OPERATIONAL PROCEDURES FOR SAFE MANAGEMENT OF SMALL BREAKS IN THE REACTOR COOLANT SYSTEM PRESSURE BOUNDARY

Operational guidelines will be prepared for the safe handling of small breaks as an extension of and addition to previously issued guidelines and IE Bulletin 79-05A. These guidelines will include provisions for operator recognition of small breaks and discrimination of other accidents which might produce similar symptoms.

The guidelines will include expected system response insofar as required to assure effective operator understanding and action. The guidelines will include necessary precautions and will describe those actions which the operator must take to assure safe management and mitigation of small break events, including natural circulation cooling where it is predicted to occur in the course of the accident.

These guidelines will specifically cover cases in which RCS stabilization will occur with a partially filled reactor coolant system for both the case with the reactor coolant pumps on and the reactor coolant pumps off. Delay in the initiation of auxiliary feedwater up to 20 minutes will be considered. System conditions covered will assume availability of ECCS systems at full design flow in the event that auxiliary feedwater is not available or with single failure in the ECCS systems in the event that auxiliary feedwater is available.

The guidelines will be based on existing analyses and by specific additional computer calculations. These calculations will be performed to define system response to re-start of reactor coolant pumps in a partially filled system and response of the partially filled system to re-start of auxiliary feedwater.

These guidelines will be developed by B&W and reviewed by the NRC staff in time for implementation of the corresponding procedures by Duke Power Company on or before May 15, 1979.

APRIL 26, 1979

ARKANSAS POWER & LIGHT COMPANY
POST OFFICE BOX 551 LITTLE ROCK, ARKANSAS 72203 (501) 371-4422

May 3, 1979

WILLIAM CAVANAUGH III
Vice President
Generation & Construction

1-059-1

Dr. Harold R. Denton
Director, Nuclear Reactor Regulation
1717 H Street North West
Washington, D. C. 20555

Subject: Arkansas Nuclear One - Unit 1
Docket No. 50-313
License No. DPR-51
(File: 1510)

Dear Mr. Denton:

In response to the staff safety concerns identified as items a. through e. on pages 1-7 of ONRR Status Report to the Commission of April 25, 1979, Arkansas Power and Light proposes the following actions:

(a) Upgrade of the timeliness and reliability of the Emergency Feedwater (EFW system by performing the items specified in Enclosure 1.

(b) Develop and implement operating/emergency procedures for initiating and controlling EFW independent of Integrated Control System (ICS) control.

(c) Implement a hard-wired control-grade reactor trip on loss of main feedwater or on turbine trip.

(d) Complete sufficient small break LOCA analyses to develop and implement necessary operator instructions in the emergency procedures.

(e) At least one Licensed Operator who has had TMI-2 training on the B&W simulator will be assigned to the control room (one each shift).

Arkansas Nuclear One - Unit 1 (ANO-1) is currently shutdown and will not be restarted until the items a. through e. above are completed.

To provide an increased margin of safety the following "Long-term" items will be implemented:

1) The items in Enclosure 2 will be implemented during our next outage (following completion of the design change engineering) to cold shutdown conditions which is of sufficient length to accommodate the change but no later than the next refueling outage. Further we will provide a schedule for implementing any other modifications identified as necessary as a result of our reviews shown on Enclosure 1.

2) The failure modes and effects analysis (FMEA) of the ICS is underway with high priority and will be submitted as soon as practicable.

3) The hard-wired trips addressed in Item c. above will be upgraded to safety grade.

4) Complete the ECCS small breaks analyses as outlined in Enclosure 3.

5) We will continue operator training and drilling of response procedures as a part of our ongoing program to assure the high state of readiness and safe operation at ANO-1.

AP&L is confident that these steps will resolve the Staff concerns and provide an additional degree of assurance of public safety.

Very truly yours,

William Cavanaugh III

William Cavanaugh III

WC:JTE:vb

Enclosures

ENCLOSURE (1)

EMERGENCY FEEDWATER SYSTEM UPGRADE

1. Review procedures, revise as necessary and conduct training to ensure timely and proper starting of motor driven emergency feedwater (EFW) pump from an engineered safeguards bus upon loss of offsite power.

2. To assure that EFW will be aligned in a timely manner to inject on all EFW demand events when in the surveillance test mode, procedures will be implemented and training conducted to provide an operator at the necessary valves in communication with the control room during the surveillance mode to carry out the valve alignment changes upon EFW demand events.

3. Write and implement procedures for the manual initiation and control of the EFW System following failure of the Integrated Control System.

4. The EFW pumps will be verified operable in accordance with the ANO-1 Technical Specifications and Surveillance Procedures.

5. Review and revise, as necessary, the procedures and conduct training for providing alternate sources of water to the suction of the EFW pumps.

6. In the event emergency feedwater is necessary and offsite power is available, an auto start signal will be provided to the motor driven emergency feedwater pump.

7. Procedures will be developed and implemented and training conducted to provide guidance for timely operator verification of any automatic initiation of EFW.

8. Verification that Technical Specification requirements for EFW capacity are in accordance with the accident analysis will be conducted.

9. Modifications will be made to provide verification in the control room of EFW flow.

ENCLOSURE (2)

EMERGENCY FEEDWATER SYSTEM UPGRADE

1. Connect the motor driven Emergency Feedwater (EFW) pump to a vital AC power supply.

2. Modify the suction piping to improve system separation.

3. Modifications will be made to provide verification in the control room of EFW flow to each steam generator.

4. Provide control room annunciation for all auto start conditions of the EFW system.

ENCLOSURE (3) May 3, 1979

GUIDELINES FOR THE DEVELOPMENT OF OPERATIONAL PROCEDURES FOR SAFE MANAGEMENT OF SMALL BREAKS IN THE REACTOR COOLANT SYSTEM PRESSURE BOUNDARY

Operational guidelines will be prepared for the safe handling of small breaks as an extension of and addition to previously issued guidelines and IE Bulletin 79-05A. These guidelines will include provisions for operator recognition of small breaks and discrimination of other accidents which might produce similar symptoms.

The guidelines will include expected system response insofar as required to assure effective operator understanding and action. The guidelines will include necessary precautions and will describe those actions which the operator must take to assure safe management and mitigation of small break events, including natural circulation cooling where it is predicted to occur in the course of the accident.

These guidelines will specifically cover cases in which RCS stabilization will occur with a partially filled reactor coolant system for both the case with the reactor coolant pumps on and the reactor coolant pumps off. Delay in the initiation of auxiliary feedwater up to 20 minutes will be considered. System conditions covered will assume availability of ECCS systems at full design flow in the event that auxiliary feedwater is not available or with single failure in the ECCS systems in the event that auxiliary feedwater is available.

The guidelines will be based on existing analyses and by specific additional computer calculations. These calculations will be performed to define system response to restart of reactor coolant pumps in a partially filled system and response of the partially filled system to restart of auxiliary feedwater.

These guidelines will be developed by B&W and reviewed by the NRC staff in time for implementation of the corresponding procedures by Arkansas Power & Light on or before May 15, 1979.

APPENDIX F

15830

SMUD SACRAMENTO MUNICIPAL UTILITY DISTRICT, 6201 S ST., P. O. BOX XXXX SACRAMENTO 11, CALIFORNIA, GL 2-3211

April 27, 1979

Mr. Harold R. Denton
Director
Office of Nuclear Reactor Regulation
USNRC
Washington, D. C. 20555

Re: Rancho Seco Nuclear Station
Docket No. 50-312

Dear Mr. Denton:

In response to the staff safety concerns identified as items a. through e. on page 1-7 of the ONRR Status Report to the Commission of April 25, 1979, the Sacramento Municipal Utility District proposes the following actions:

(a) Upgrade of the timeliness and reliability of delivery from the Auxiliary Feedwater System by carrying out items 1 through 9 identified in enclosure 1.

(b) Develop and implement operating procedures for initiating and controlling auxiliary feedwater independent of ICS control.

(c) Implement a hard-wired control-grade reactor trip on loss of main feedwater and/or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) The District will provide for one Senior Licensed Operator assigned to the control room who has had TMI-2 training on the B&W simulator.

Rancho Seco will be shutdown on April 28, 1979 and will not be restarted until item a. through e. above are completed.

The District further commits to the following additional actions for improvement and in assuring safety that is related to items a. through e. in ONRR Status Report of April 25, 1979:

7904300269

(a) The District will provide a proposed schedule for implementation of identified design modifications which specifically relate to items 1 through 9 of enclosure 1 and would significantly improve safety.

(b) The failure mode and effects analysis of ICS is underway with high priority by B&W and will be submitted as soon as practicable.

(c) The hard-wired trips will be revised to safety grade.

(d) A more complete description of the transient analyses is provided in enclosure 2 entitled "Guidelines for the Development of Operational Procedures for Safe Management of Small Breaks in the Reactor Coolant System Pressure Boundary."

(e) The District will continue operator training and drilling and will have a minimum of two licensed operators per shift with TMI-2 simulator training at B&W by June 1, 1979. Thereafter at least one licensed operator with TMI-2 simulator training at B&W will be assigned to the Control Room. All training of licensed personnel will be completed by June 28, 1979.

The District is confident that these steps will meet your Staff concerns and provide additional assurance of public safety.

J. J. Mattimoe

J. J. Mattimoe
Assistant General Manager
and Chief Engineer

ENCLOSURE (1)

Auxiliary Feedwater System Upgrade

1. Review procedures, revise as necessary and conduct training to ensure timely and proper starting of motor driven auxiliary feedwater (AFW) pump(s) from vital AC buses upon loss of offsite power.

2. To assure that AFW will be aligned in a timely manner to inject on all AFW demand events when in the surveillance test mode, procedures will be implemented and training conducted to provide an operator at the necessary valves in phone communications with the control room during the surveillance mode to carry out the valve alignment changes upon AFW demand events.

3. Procedures will be developed and implemented and training conducted to provide for control of steam generator level by use of safety grade AFW bypass valves in the event that ICS steam generator level control fails.

4. Verification that Technical Specification requirements of AFW capacity are in accordance with the accident analysis will be conducted. Pump capacity with mini flow in service will also be verified.

5. Modifications will be made to provide verification in the control room of AFW flow to each steam generator.

6. Review and revise, as necessary, the procedures and training for providing alternate sources of water to the suction of the AFW pumps.

7. Design review and modification, as necessary, will be conducted to provide control room annunciation for all auto start conditions of the AFW system.

8. Procedures will be developed and implemented and training conducted to provide guidance for timely operator verification of any automatic initiation of AFW.

9. Verification will be made that the air operated level control valves (a) Fail to the 50% open position upon loss of electrical power to the electrical to pressure converter, and (b) Fail to the 100% open position upon loss of service air. The AFW bypass valves are safety grade.

April 27, 1979

ENCLOSURE (2)

GUIDELINES FOR THE DEVELOPMENT OF OPERATIONAL PROCEDURES FOR SAFE MANAGEMENT OF SMALL BREAKS IN THE REACTOR COOLANT SYSTEM PRESSURE BOUNDARY

Operational guidelines will be prepared for the safe handling of small breaks as an extension of and addition to previously issued guidelines and IE Bulletin 79-05A. These guidelines will include provisions for operator recognition of small breaks and discrimination of other accidents which might produce similar symptoms.

The guidelines will include expected system response insofar as required to assure effective operator understanding and action. The guidelines will include necessary precautions and will describe those actions which the operator must take to assure safe management and mitigation of small break events, including natural circulation cooling where it is predicted to occur in the course of the accident.

These guidelines will specifically cover cases in which RCS stabilization will occur with a partially filled reactor coolant system for both the case with the reactor coolant pumps on and the reactor coolant pumps off. Delay in the initiation of auxiliary feedwater up to 20 minutes will be considered. System conditions covered will assume availability of ECCS systems at full design flow in the event that auxiliary feedwater is not available or with single failure in the ECCS systems in the event that auxiliary feedwater is available.

ENCLOSURE (2)

The guidelines will be based on existing analyses and by specific additional computer calculations. These calculations will be performed to define system response to re-start of reactor coolant pumps in a partially filled system and response of the partially filled system to re-start of auxiliary feedwater.

These guidelines will be developed by B&W and reviewed by the NRC staff in time for implementation of the corresponding procedures by the Sacramento Municipal Utility District on or before May 15, 1979.

APRIL 27, 1979

Florida Power
CORPORATION

B.L. Griffin, P.E.
Senior Vice President
Engineering & Construction

May 1, 1979

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

Subject: Crystal River Unit 3
Docket No. 50-302
Operating License DPR-72

Dear Mr. Denton:

In response to Staff safety concerns identified as items a. through e. on page 1-7 of the ONRR Status Report to the Commission of April 25, 1979, Florida Power Corporation proposes to implement the following interim actions until further analysis of these concerns can be completed:

(a) Upgrade of the timeliness and reliability of delivery from the Emergency Feedwater System by carrying out items 1 through 9 identified in Enclosure 1.

(b) We have developed and implemented operating procedures for initiating and controlling emergency feedwater independent of ICS control.

(c) Implement a hard-wired control-grade reactor trip on loss of main feedwater or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) All Control Room operators have completed TMI-2 training on the B&W simulator.

Crystal River Unit 3 is shutdown for maintenance and refueling and Florida Power Corporation has committed in our April 27, 1979, letter to you to resolve and implement items a. through e. prior to startup which is currently scheduled for June 1, 1979.

FPC further commits to the following ongoing/long term actions for improvement and assuring safety at Crystal River Unit 3:

(a) The failure mode and effects analysis of ICS is underway with high priority by B&W and will be submitted as soon as practicable.

(b) Upon completion of a detailed design and supporting analysis, the hard-wired trip will be revised to a safety grade system.

(c) Modifications will be made to provide verification in the control room of EFW flow to each steam generator.

(d) A more complete description of the small breaks transient analyses is provided in Enclosure 2, entitled "Guidelines for the Development of Operational Procedures for Safe Management of Small Breaks in the Reactor Coolant System Pressure Boundary."

(e) We will continue operator training and drilling of response procedures as a part of our ongoing program to assure the high state of readiness and safe operation at CR3.

We are confident that this action will meet your Staff concerns and provide additional assurance of the health and safety of the public.

Very truly yours,

B. L. Griffin

B. L. Griffin

PYBekcS01
D65

Enclosures

STATE OF FLORIDA

COUNTY OF PINELLAS

B.L. Griffin states that he is the Senior Vice President, Engineering and Construction, Florida Power Corporation; that he is authorized on the part of said company to sign and file with the Nuclear Regulatory Commission the information attached hereto; and that all such statements made and matters set forth therein are true and correct to the best of his knowledge, information and belief.

B. L. Griffin

Subscribed and sworn to before me, a Notary Public in and for the State and County above named, this 1st day of May, 1979.

Charles R. Pope
Notary Public

Notary Public, State of Florida at Large,
My Commission Expires: July 25, 1980
(Notary 1 D12)

ENCLOSURE (1) May 1, 1979

AUXILIARY FEEDWATER SYSTEM UPGRADE

1. Review procedures, revise as necessary and conduct training to ensure timely and proper starting of motor driven emergency feedwater (EFW) pump from engineered safeguards bus A upon loss of offsite power.

2. To assure that EFW will be aligned in a timely manner to inject on all EFW demand events when in the surveillance test mode, procedures will be implemented and training conducted to provide an operator at the necessary valves in communication with the control room during the surveillance mode to carry out the valve alignment changes upon EFW demand events.

3. Emergency feedwater bypass valves are normally in the open position. Procedures have been developed and implemented to require the operator to take control of these valves upon failure of the ICS steam generator level control. If the ICS level control does not fail the operator will close the bypass valves. Those valves in the EFW system not locked in position are verified to be in the proper position on a daily basis. Training will be conducted on these revised procedures prior to June 1, 1979.

4. The EFW pumps will be verified operable in accordance with the CR#3 Technical Specifications and Surveillance Procedures.

5. Review and revise, as necessary, the procedures and training for providing alternate sources of water to the suction of the EFW pumps.

6. Remove the interlock which prevents the turbine-driven emergency feedwater pump operation when the motor driven emergency feedwater pump is running.

7. In event emergency feedwater is necessary and offsite power is available, an auto start signal will be provided to the motor driven emergency feedwater pump.

8. Design review and modification, as necessary, will be conducted to provide control room annunciation for auto start conditions of the EFW system.

9. Verification has been made that the air operated level control valves (a) fail to the 50% open position upon loss of power to the electrical/pressure converter, and (b) fail to the as is position upon loss of instrument air and electrical power to the air lock. At full load these valves are in the full (100%) open positions and at low power levels (below 15%) they are partially open controlling flow. If these valves were to fail closed, feedwater flow would be controlled using the EFW bypass valves as described in Item 3 above.

PYBekcS01(D65)

ENCLOSURE (2) May 1, 1979

GUIDELINES FOR THE DEVELOPMENT OF OPERATIONAL PROCEDURES FOR SAFE MANAGEMENT OF SMALL BREAKS IN THE REACTOR COOLANT SYSTEM PRESSURE BOUNDARY

Operational guidelines will be prepared for the safe handling of small breaks as an extension of and addition to previously issued guidelines and IE Bulletin 79-05A. These guidelines will include provisions for operator recognition of small breaks and discrimination of other accidents which might produce similar symptoms.

The guidelines will include expected system response insofar as required to assure effective operator understanding and action. The guidelines will include necessary precautions and will describe those actions which the operator must take to assure safe management and mitigation of small break events, including natural circulation cooling where it is predicted to occur in the course of the accident.

These guidelines will specifically cover cases in which RCS stabilization will occur with a partially filled reactor coolant system for both the case with the reactor coolant pumps on and the reactor coolant pumps off. Delay in the initiation of auxiliary feedwater up to 20 minutes will be considered. System conditions covered will assume availability of ECCS systems at full design flow in the event that auxiliary feedwater is not available or with single failure in the ECCS systems in the event that auxiliary feedwater is available.

The guidelines will be based on existing analyses and by specific additional computer calculations. These calculations will be performed to define system response to restart of reactor coolant pumps in a partially filled system and response of the partially filled system to restart of auxiliary feedwater.

These guidelines will be devloped by B&W and reviewed by the NRC staff in time for implementation of the corresponding procedures by Florida Power Corporation on or before startup.

TOLEDO
EDISON

LOWELL E. ROE
Vice President
Facilities Development
(419) 259-5242

TELECOPIED

April 27, 1979

Docket No. 50-346
License No. NPF-3
Serial No. 497

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

Dear Mr. Denton:

In your meeting of April 24, 1979 with representatives of Babcock & Wilcox and four licensees, including Toledo Edison, who have B&W nuclear steam supply systems, a number of concerns were expressed by you and your staff regarding certain features of the B&W plants. These concerns were further detailed in your NRR Status Report on Feedwater Transients in B&W Plants of April 25, 1979. In this report, on page 1-7, certain suggested steps were outlined which, if taken, would provide assurance to you that the B&W plants could continue to operate without undue risk.

While we feel that a number of design features already incorporated in the Davis-Besse Unit 1 fully meet or exceed the criteria you are requesting and that Davis-Besse can be operated without undue risk, we are proposing the following actions:

A. Auxiliary Feedwater System Reliability and Performance

The auxiliary feedwater system for the Davis-Besse Unit 1 is a reliable full safety grade system with redundancy for meeting the single failure criteria. The principal features are detailed in Table 2.1 of your report.

We, however, will continue to review all aspects of this system to further upgrade components for added reliability and performance. One such item is an installation of dynamic braking on the auxiliary feed pump turbine speed changer to further minimize level fluctuation in the steam generator when on auxiliary feed.

B. Integrated Control System (ICS) Influence on Auxiliary Feedwater Control

The Davis-Besse auxiliary feedwater control system is a full safety grade system completely independent of ICS. The auxiliary feedwater master control is capable of being switched to ICS for a backup means of control, but this option is to be removed immediately by administrative procedures.

7904300444

C. <u>Anticipatory Scram of Reactor</u>

Addition of a hard wired control grade reactor trip on loss of main feedwater or turbine trip.

D. <u>Small Break Analysis</u>

Work with B&W to complete the analyses for potential small breaks and develop and implement any necessary operating procedures to define operator action.

E. <u>Operating Procedures and Operator Training</u>

All procedures needed to be developed or modified by actions A thru D will be completed and training of the operators in the procedures will be done. All licensed shift operators will have received B&W simulator training on the TMI-2 incident.

All of the proposed actions outlined in A thru D above would be taken prior to start-up from the current maintenance outage.

Toledo Edison will continue efforts to provide additional improvements related to A thru D as follows:

A. Continue to review performance of the system for assurance of reliability and performance.

B. The failure mode and effects analysis of ICS is under way with priority by B&W and will be submitted as soon as possible.

C. The reactor trips will be revised to safety grade as far as possible.

D. Continuing attention will be given to transient analysis and procedures for management of small breaks.

E. Continue operator training and retraining as a part of our ongoing program to continue to assure the high state of readiness of our operating staff.

We are confident that these actions on our part will satisfy your concerns and provide additional and full assurance for public safety.

Yours very truly,

Lowell E. Roe

Lowell E. Roe
Vice President
Facilities Development
The Toledo Edison Company

LER.r

Met-Ed GPU

Metropolitan Edison Company
Post Office Box 480
Middletown, Pennsylvania 17057
717 944-4041

April 16, 1979
GQL 0527

Office of Nuclear Reactor Regulation
Attn: Mr. Harold Denton, Director
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Sir:

Three Mile Island Nuclear Station, Unit 2 (TMI-2)
Docket No. 50-320
License No. DPR-73

Attached is a Preliminary Sequence of Events spanning the first approximately twenty hours following the TMI-2 accident which was initiated at 4:00 a.m. on March 28, 1979.

For this chronology of events, a reference clock was established with the time of the turbine trip, 0400:37, defined as time zero. The time of each event in the sequence is given as the number of hours, minutes and seconds relative to 0400:37, followed in parenthesis by the real time using a 24-hour clock. For example, 1:52:43 p.m. on March 28 would be written "9:52:06 (1352:43)". Depending upon the accuracy of the source of data for each event, the times appear alone or with the notation "approximate".

The sequence has been reconstructed from various information and data sources, including control room logs, strip chart recorders, alarm printouts and reactimeter printouts. Please note, however, that the alarm printer was out of service from 01:13:27 (0513:59) to 02:47:31 (0648:08) and during the course of the accident was running well behind the actual time of events. Efforts to annotate this chronology and to develop graphs of various plant parameters as a function of time are underway. This additional information will be provided as soon as it is available and we will keep you informed of our progress.

Sincerely,

J. G. Herbein
J. G. Herbein
Vice President-Generation

JGH:RAL:djh

Enclosure

PRELIMINARY SEQUENCE OF EVENTS
TMI 2 ACCIDENT OF MARCH 28, 1979
Issued April 16, 1979

-00:05:00 (0355:36) Three Mile Island Unit Two was at 97% power with the Integrated Control System in full automatic. Rod groups one thru five were fully withdrawn, rod groups six and seven were 95% withdrawn and rod group eight was 27% withdrawn. Reactor Coolant System total flow was approximately 107.5% of design flow and the Reactor Coolant System pressure was 2155 psig. Reactor Coolant Makeup Pump B (MU-P-1B) was in service supplying makeup and Reactor Coolant Pump Seal injection flow. The Reactor Coolant System soluble boron concentration was approximately 1030 parts per million. Pressurizer Spray Valve (RC-V1) and the pressurizer heaters were in manual control while spraying the pressurizer to equalize boron concentrations between the pressurizer and the remainder of the Reactor Coolant System. Normal Reactor Coolant System letdown flow was established.

Steam Generator parameters were as shown in the following table:

	Steam Generator A	Steam Generator B
Loop Feedwater	5.7459 MPPH*	5.7003 MPPH*
Operating Level	56%	57.4%
Startup Level	158.8 inches	163.4 inches
Steam Pressure	910 psig	889.6 psig
Feedwater Temperature	462.7F	462.7F

* MPPH is Million Pounds Per Hour

Steam Generator Feedwater Pumps (FW-P-1A and FW-P-1B) were in service, Condensate Booster Pumps (CO-P-2A, CO-P-2B and CO-P-2C) were in service, and Condensate Pumps (CO-P-1A and CO-P-1B) were in service. An attempt was being made to clear a clogged resin transfer line in the standby demineralizer.

-00:00:01 (0400:36)	Condensate Pump A (CO-P-1A) stopped.
-00:00:01 (0400:36)	Feedwater Pumps (FW-P-1A and FW-P-1B) stopped at essentially the same time resulting in a loss of feedwater flow to both steam generators.
00:00:00 (0400:37)	Main Generator was tripped followed by a turbine trip.
00:00:00 (0400:37)	Three Emergency Feedwater Pumps (EF-P-1, 2A, 2B) started.
00:00:03 (0400:40) Approximate	The Electromatic Relief Valve (RC-RV2) opened at the setpoint of 2255 psig.
00:00:08 (0400:45)	Reactor tripped on high pressure at 2345 psi. Setpoint is 2355 psi.
00:00:08 (0400:45) Approximate	The operator placed the Pressurized Spray Valve (RC-V1) and pressurizer heaters under automatic control.
00:00:13	The operator started the Reactor Coolant Makeup Pump A (MU-P-1A), opened High Pressure Injection Isolation Valve A (MU-V16A) and isolated letdown flow in anticipation of the expected pressurizer level decrease.

00:00:13 (0400:50) Approximate	The Electromatic Relief (RC-RV2) solenoid de-energized giving a non-open indication to the control room operators. The Electromatic Relief Valve (RC-RV2) should have reseated at about this time (closure setpoint of 2205 psig).
00:00:14 (0400:51)	The Emergency Feed Pumps (EF-P1, 2A and 2B) achieved normal discharge pressure.
00:00:15 (0400:52) Approximate	Water hammer in the condensate piping occurred.
00:00:30 (0401:07)	Pressurizer Safety Valve (RC-RV1B) and Electromatic Relief Valve (RC-RV2) discharge line temperature alarms printed out.
00:00:38 (0401:15) Approximate	Steam Generator A level reached the 30-inch setpoint where the Emergency Feedwater Valves (EF-V11A and EF-V11B) open. Feedwater was not admitted because Emergency Feedwater Block Valves (EF-V12A and EF-V12B) were shut.
00:00:39 (0401:16)	Reactor Coolant Makeup Pump A (MU-P-1A) was stopped.
00:00:40 (0401:17) Approximate	Steam Generator B level reached the 30-inch setpoint where the Emergency Feedwater Valves (EF-V11A and EF-V11B) open. Feedwater was not admitted because Emergency Feedwater Block Valves (EF-V12A and EF-V12B) were shut.
00:00:41 (0401:18)	Reactor Coolant Makeup Pump A (MU-P-1A) was restarted. With Reactor Coolant Makeup Pumps A and B (MU-P-1A and MU-P-1B) operating, pressurizer level rate of decrease slowed.

00:01:00 (0401:37) Approximate	Pressurizer level started increasing. Reactor Coolant System hot leg and cold leg temperatures reached 575F. Reactor Coolant Drain Tank pressure was increasing.
00:01:00 (0401:37)	The Pressurizer Safety Valve (RC-RV1A) high discharge line temperature alarm was received.
00:01:26 (0402:03)	Reactor Coolant Drain Tank temperature normal alarm printed out.
00:01:45 (0402:22) Approximate	Steam Generators A and B have boiled dry at this time.
00:02:01 (0402:38)	Reactor Coolant Makeup Pump B (MU-P-1B) was stopped due to Engineered Safeguards actuation.
00:02:04 (0402:41)	High Pressure Injection Pump C (MU-P-1C) started automatically.
00:03:12 (0403:49) Approximate	Reactor Coolant Drain Tank Relief Valve (WDL-R1) lifted at 120 psig.
00:03:14 (0403:51)	High Pressure Injection portion of Engineered Safeguards was manually bypassed. Both Reactor Coolant Makeup Pumps A and C (MU-1P-1A and MU-P-1C) were operating.
00:03:26 (0404:03)	Reactor Coolant Drain Tank high temperature alarm received at 127.2F.
00:04:38 (0405:15)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
00:04:38 (0405:15) Approximate	The operator throttled the High Pressure Injection Isolation Valves (MU-V16's).

00:04:52 (0405:29)	Intermediate Closed Cooling Pump (IC-P-1A) started.
00:04:58 (0405:35)	First alarm indication received that letdown had been secured.
00:05:06 (0405:43)	Presurizer level stopped its sharp increase at 376 inches and began to turn down. It reached a minimum of 372 inches and then started back up at 5 minutes, 21 seconds into the transient.
00:05:15 (0405:52)	Condensate Booster Pump B (CO-P-2B) tripped.
00:05:50 (0406:27) Approximate	Reactor Coolant System pressure stopped its sharp decrease and began to turn up. Minimum value reached was approximately 1350 psig.
00:05:54 (0406:31)	Pressurizer level increased beyond the range of the instrument indication.
00:06:58 (0407:35)	Letdown flow of 71.4 gallons per minute was re-established.
00:07:31 (0408:06)	Reactor Building Sump Pump A (WDL-P-2A) started.
00:08:00 (0408:37) Approximate	Emergency Feedwater Block Valves (EF-V12A and EF-V12B) were opened.
00:08:15 (0408:52)	Reactor Coolant System hot leg and cold leg temperatures began to decrease.
00:08:30 (0409:07)	Reactor Coolant System pressure began to decrease.
00:10:00 (0410:37)	Pressurizer level came on scale.

00:10:19 (0410:56)	Reactor Building Sump Pump B (WDL-P-2B) started.
00:10:24 (0411:01)	Reactor Coolant Makeup Pump A (MU-P-1A) tripped.
00:10:27 (0411:04)	Reactor Coolant Makeup Pump A (MU-P-1A) was started.
00:10:28 (0411:05)	Reactor Coolant Makeup Pump A (MU-P-1A) tripped.
00:10:40 (0411:25)	Reactor Building Sump high level alarm received. Setpoint is 4.650 feet.
00:11:40 (0412:17)	Reactor Coolant Makeup Pump A (MU-P-1A) was started.
00:14:50 (0415:27)	The Reactor Coolant Drain Tank rupture diaphragm (WDL-U26) failed.
00:24:58 (0425:35	The operator requested computer printout of the Electromatic Relief Valve (RC-RV2) outlet temperature. The reading was 285.4F.
00:25:00 (0425:37) Approximate	Intermediate Cooling System high radiation alarm annunciator received at the Radiation Monitor Panel.
00:36:08 (0436:45)	Emergency Feedwater Pump 2B (EF-P-2B) was stopped.
00:38:10 (0438:47)	Reactor Building Sump Pump A (WDL-P-2A) was stopped.
-00:38:11 (0438:48)	Reactor Building Sump Pump B (WDL-P-2B) was stopped.
01:10:54 (0511:31)	Reactor Building air cooling coils emergency discharge alarm printed out.

01:13:29 (0514:06)	Reactor Coolant Pump 2B (RC-P-2B) was stopped.
01:13:42 (0514:19)	Reactor Coolant Pump 1B (RC-P-1B) was stopped.
01:13:27 (0513:59)	The alarm printer became unavailable at this time and remained out of service until 02:47:31 (0648:08).
01:20:31	Operator requested printout of the Electromatic Relief Valve (RC-RV2) outlet temperature. The reading was 283.0F.
01:40:37 (0541:14)	Reactor Coolant Pump 2A (RC-P-2A) was stopped.
01:40:45 (0541:22)	Reactor Coolant Pump 1A (RC-P-1A) was stopped.
01:42:00 (0542:37) Approximate	Operator started raising Steam Generator A level from 30 inches on the Startup Range to 50% on Operating Range. Reactor Coolant System Loops A and B cold leg temperatures both started decreasing. Reactor Coolant System pressure started decreasing.
01:54:00 (0554:37) Approximate	Reactor Coolant System Loop A hot leg temperature began increasing.
02:00:00 (0600:37) Approximate	Steam Generator A level reached 50% on Operating Range.
02:00:00 (0600:37)	Reactor Coolant System Loop B hot leg temperature began increasing.
02:12:00 (0612:37)	Reactor Coolant System Loop B hot leg temperature increased to offscale at 620F.

02:17:53 (0618:30)	Operator requested Electromatic Relief Valve (RC-R2) outlet temperature. The reading was 228.7F.
02:22:00 (0622:37) Approximat	The Electromatic Relief Block Valve (RC-V2) was shut.
02:30:00 (0630:37)	Operator started increasing Steam Generator B from 30 inches on Startup Range to 50% on Operating Range.
02:45:00 (0645:37) Approximate	Several radiation alarms were received.
02:45:00 (0645:37) Approximate	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
02:45:00 (0645:37) Approximate	Operator opened Main Steam Isolation Valves (MS-V4B and MS-V7B).
02:50:00 (0650:37) Approximate	Site Emergency was declared. Notifications to offsite authorities and organizations were initiated.
02:51:57 (0652:34)	Operator attempted to start Reactor Coolant Pump 2A (RC-P-2A). Pump would not start.
02:53:19 (0653:53)	Operator attempted to start Reactor Coolant Pump 1B (RC-P-1B). Pump would not start.
02:54:09 (0654:46)	Operator started Reactor Coolant Pump 2B (RC-P-2B).
02:54:49 (0655:26)	High Pressure Injection Engineered Safeguards actuation logic reset on increasing Reactor Coolant System pressure.

02:56:19 (0656:56) Approximate	Steam Generator B was isolated. Main Steam Isolation Valves (MS-V4B and MS-V7B) were shut.
03:00:00 (0700:37) Approximate	Reactor Coolant System pressure increased to 2130 psig.
03:03:39 (0704:16) Approximate	Steam Generator A pressure control was shifted from the Turbine Bypass Valves (MSV-25A and B and MSV-26A and B) to the Power Operated Emergency Main Steam Dump Valves (MSV-3A and B).
03:10:27 (0711:04)	Emergency Feedwater Pump 2A (EF-P-2A) was stopped.
03:12:28 (0713:05) Approximate	Electromatic Relief Block valve (RC-V2) was opened.
03:12:53 (0712:53)	Reactor Coolant Pump 2B (RC-P-2B) was stopped.
03:20:13 (0720:41)	Reactor Coolant Makeup Pump C (MU-P-IC) was started. Reactor Coolant Makeup Pumps C and A (MU-P-C and A) were operating.
03:23:23 (0724:00) Approximate	General Emergency was declared. Notifications to offsite authorities and organizations were initiated.
03:30:00 (0730:37) Approximate	Electromatic Relief Block Valve (RC-V2) was shut.
03:35:08 (0735:43)	Emergency Feedwater Pump 2A (EF-P-2A) was started.
03:37:00 (0737:37)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
03:51:00 (0751:37) Approximate	Electromatic Relief Block Valve (RC-V2) was opened.

03:55:39 (0756:16)	Engineered Safeguards actuated on low RCS pressure. Setpoint is 1640 psig.
03:55:39 (0756:16)	The Reactor Building high pressure isolation signal actuated and isolated the Reactor Building. The Reactor Building isolation set point is 4 psig.
03:56:04 (0756:41)	Reactor Coolant Makeup Pump C (MU-P-1C) was started.
03:59:23 (0800:00)	Reactor Building Emergency Cooler B was shutdown.
03:59:53 (0800:30)	Reactor Building Emergency Cooler B was started.
04:06:00 (0806:37)	Electromatic Relief Block Valve (RC-V2) was shut.
04:08:37 (0809:14)	Reactor Coolant Pump 1A (RC-P-1A) was started.
04:09:14 (0809:51)	Reactor Coolant Pump 1A (RC-P-1A) was stopped.
04:17:17 (0817:54)	Reactor Coolant Makeup Pump A (MU-P-1A) was stopped.
04:17:22 (0817:59)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped. No makeup pumps operating.
04:18:17 (0818:54)	Operator attempted to start Reactor Coolant Makeup Pump A (MU-P-1A). The pump would not start.
04:18:30 (0819:07) Approximate	Electromatic Relief Block Valve (RC-V2) was opened.

04:21:53 (0818:30)	Reactor Coolant Makeup Pump B (MU-P-1B) was started.
04:26:59 (0827:36) Approximate	Reactor Coolant Makeup Pump C (MU-P-1C) was started, tripped, and was restarted.
04:30:00 (0830:37) Approximate	The Electromatic Relief Block Valve (RC-V2) was shut.
04:30:45 (0831:22)	Condenser Vacuum Pumps 1A and 1C (VA-P-1A and VA-P-1C) were stopped and vacuum was broken.
04:30:45 (0831:22) Approximate	Power Operated Emergency Main Steam Dump Valve (MS-V3A) was opened.
04:54:00 (0854:37) Approximate	The Electromatic Relief Block Valve (RC-V2) was opened.
05:18:00 (0918:37)	The Electromatic Relief Block Valve (RC-V2) was shut.
05:54:00 (0954:37) Approximate	Operator commenced filling Steam Generator A to 99% on the Operating Range instrumentation.
07:30:00 (1130:37) Approximate	Electromatic Relief Block Valve (RC-V2) and the Pressurizer Spray Valve (RC-V1) were opened.
08:11:26 (1212:03)	Core Flood Tank A high level alarm was received.
08:30:00 (1230:37)	Power Operated Emergency Main Steam Dump Valve (MS-V3A) was shut.

08:31:06 (1231:43)	Decay Heat Removal Pumps 1A and 1B (DH-P-1A and DH-P-1B) were started.
08:54:56 (1255:33)	Core Flood Tank A alarm printed out at a level of 13.13 feet.
09:04:18 (1304:55)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
09:49:44 (1350:21)	Reactor Building Isolation and Containment Spray were actuated by Engineered Safeguards. Engineered Safeguards actuation started Reactor Coolant Makeup Pump C (MU-P-1C) and Reactor Building Spray Pumps A and B (BS-P-1A and BS-P-1B).
09:49:50 (1350:27)	Reactor Building Spray Valves (BS-V1A and BS-V11B) opened.
09:49:58 (1350:35)	Reactor Coolant Pumps 1A and 1B (RC-P-1A and RC-P-1B) inlet air temperature high alarms annunciated and Pressurizer Safety Valves (RC-R1A and RC-R1B) discharge line temperature high alarms annunciated.
09:50:24 (1351:01)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
09:55:30 (1356:07)	Reactor Building Spray Pumps A and B (BS-P-1A and BS-P-1B) were stopped.
09:56:58 (1357:35)	Decay Heat Removal Pumps A and B (DH-P-1A and DH-P-1B) were stopped.
10:24:00 (1424:37) Approximate	Reactor Coolant System hot leg Loop A temperature decreased to within the instrumentation range.

10:31:25 (1432:02)	Reactor Coolant Makeup Pump C (MU-P-1C) was started. Reactor Coolant pressure was approximately 440 psig.
10:35:55 (1436:32)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
11:06:00 (1406:37) Approximate	Pressurizer level started decreasing.
11:12:00 (1512:37) Approximate	Reactor Coolant System cold leg Loop A temperature started to increase from 200F to 400F. Reactor Coolant System hot leg Loop A temperature decreased from above the instrument range to 560F.
11:18:34 (1519:11)	Reactor Coolant Makeup Pump C (MU-P-1C) was started.
11:24:00 (1524:37) Approximate	Pressurizer level stopped decreasing at 180 inches and started increasing, going off scale during the next hour.
11:28:12 (1528:49)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
11:32:37 (1533:14)	Reactor Coolant Makeup Pump C (MU-P-1C) was started.
11:35:48 (1536:25)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
11:36:00 (1536:37) Approximate	Operator commenced filling Steam Generator B to 97% on the Operating Range instrumentation.
12:00:00 (1600:37) Approximate	Steam Generator A level was 97% on the Operating Range.
12:48:00 (1648:00) Approximate	Pressurizer level came on scale.

13:02:23 (1703:00)	Condenser Vacuum Pump 1C (VA-P-1C) was started.
13:08:22 (1708:59) Approximate	Normal steam generator feedwater supply was put in service.
13:13:10 (1713:47)	Condenser Vacuum Pump 1A (VA-P-1A) was started.
13:23:04 (1723:41)	Reactor Coolant Makeup Pump C (MU-P-1C) was started.
14:43:15 (1843:52)	Reactor Coolant Makeup Pump C (MU-P-1C) was stopped.
14:54:00 (1854:37) Approximate	RCS pressure reached 2350 psig.
15:24:00 (1924:37)	Reactor Coolant Pump 1A (RC-P-1A) was started.
15:24:10 (1924:47) Approximate	Reactor Coolant Pump 1A (RC-P-1A) was stopped.
16:04:00 (2008:37)	Reactor Coolant Pump 1A (RC-P-1A) was started.
22:15:00 (0215:37) Approximate	Reactor Coolant System and Steam Generator conditions were: Reactor Coolant System pressure = 1065 psig. Pressurizer Temperature = 551F (pressurizer heaters maintaining temperature). Pressurizer Level = 397 inches. Reactor Coolant System cold leg Loop A temperature = 288F Steam Generator A steaming to the Main Condenser.

Steam Generator B isolated.

Reactor Coolant Makeup Pump B (MU-P-1B) operating to supply Reactor Coolant Pump seal injection flow.

Reactor Coolant System cold leg Loop A temperature = 256.4F.

Reactor Coolant System cold leg Loop B temperature = 252.4F.

Reactor Coolant System hot leg Loop A temperature = off scale low, i.e.,less than 520.0F.

Reactor Coolant System hot leg Loop B temperature = off scale low, i.e.,less than 520.0F.

APPENDIX J

COMMENTS ON CRYSTAL RIVER FEEDWATER SYSTEMS

Introduction

These comments were compiled during the week of April 15, 1979 from information in the FSAR and from telecons with the licensee.

Summary

Concerns about the design of Crystal River's auxiliary feedwater system are:

(1) Seismic event could cause loss of all AFW pump suction sources.

(2) The AFW pumps may not self-vent because of the system geometry.

(3) The AFW pump auto start logic is not single failure-proof.

(4) Vacuum breaker valves on main condenser can cause loss of suction to both AFW pumps from hotwell.

(5) For several scenarios with single failures, operator action would be required to get auxiliary feedwater to the steam generators.

Normal Feedwater

Two turbine driven pumps with steam sources from (1) reheat steam; (2) main steam; and (3) auxiliary steam. Shutoff head = 2550 ft. No strainers in feedwater system. Condensate demineralizers are automatically bypassed by an air-operated valve on high differential pressure across the demineralizers. (This valve could fail in any position on loss of air because it uses air as its motive force in both directions.) There are no automatic bypasses around FW heaters. Feedwater is shut off to the faulted steam generator when its steam pressure < 600 psig.

Auxiliary Feedwater (AFW) Sources

Normal supply: condensate storage tank; first backup supply: condenser hotwell; second backup: demineralized water from the fossil units. Switchover from the normal supply to the first backup can be performed from the control room in approximately 1 minute. Concern: There is no seismic category 1 source of auxiliary feedwater.

Auxiliary Feedwater Pumps

Two pumps, 1 motor driven and 1 turbine driven, 740 gpm each. Shutoff head: 3400 ft (motor) and 3500 ft (steam). Concern: The pumps are not the low point in the system and may not be self-venting.

Auxiliary Feedwater Pump Drives

The motor is on a Class 1E power supply. Steam is supplied to the turbine driver from two main steam lines upstream of the main steam isolation valves. The turbine driven pump is operable with steam pressure at least as low as 200 psig.

AFW Pumps Auto Start

The motor driven pump has no auto start signals. It must always be started by the operator. Turbine driven pump auto starts on loss of both main FW pumps (as sensed by low oil pressure on both pumps). (Does not start on safety features actuation signal.) Auto start signals are not redundant or Class 1E.

Automatic Trips of AFW Pumps

Turbine driven: overspeed
Motor driven: motor protective trips
closed suction valve

Concern: If taking suction on the hotwell (first backup), the suction valves are interlocked with the condenser vacuum breaker valves. If they are closed, the suction valves close and you lose suction to the AFW pumps. Only the motor-driven pump trips on suction valve position. The turbine-driven pump could be damaged before it trips on overspeed.

AFW Indication

Turbine driven: steam stop valve position
Motor driven: motor on-off lights, ammeter
Common: flow in startup FW line (would require valve realignment to use).

Level Control

On loss of main FW pumps, the ICS controls level at 30" after the operator closes a valve that bypasses the FCV. If all 4 reactor coolant pumps are lost, the ICS controls level at 250"after operator closes FCV bypass. Operating procedures and practice require the operator to maintain these levels if the ICS fails to do so.

Independence of AFW Trains

Appear to be independent with the following exceptions:

(1) common, non-seismic suction source (condensate storage tank).

(2) ICS inputs to flow control valves of both trains.

(3) suction valves from main condenser to AFW pumps are closed by common signal (see concern under "Automatic Trips of AFW Pumps").

Effect of Surveillance Test on System

To test one pump, its motor-operated discharge valve is closed and recirculated to condensate storage tank through the mini-flow line. Operator action would be required to open the discharge valve before that pump would deliver water to the steam generators. (Note that only 1 AFW pump starts on auto.)

Common Mode Failures That Would Cause Loss of Main FW and Auxiliary FW

None identified (except seismic event).

Seismic Event

(1) There is no seismic source of suction to the auxiliary feedwater pumps. Therefore, a seismic event could cause total loss of feedwater.

(2) The initiating logic for AFW pump is non-seismic. Therefore, the pump may not auto-start even if suction source is available.

Loss of Offsite Power

Would cause almost immediate loss of both main FW pumps. Only the turbine-driven AFW pump would auto start. Operator action would be required to start the motor-driven AFW pump on the diesel generator. Several emergency loads may have to be stripped to allow starting of this pump on the diesel generator.

Loss of Offsite Power with Single Failure

(1) Worst identified single failure is loss of turbine-driven AFW pump. This would require operator action to start motor-driven pump. Other emergency loads may have to be stripped before starting AFW pump on diesel generator.

(2) ICS - Have not investigated whether single failure can cause both AFW flow control valves to close after the operator has closed the FCV beypass valves.

System Design Response to LOCA

None.

Alternate Cooling Mode Without Main FW or AFW

None identified.

APPENDIX K

COMMENTS ON RANCHO SECO FEEDWATER SYSTEMS

Introduction

These comments were compiled during the week of April 15, 1979 from information in the FSAR and from telecons with the licensee.

Summary

(1) Loss of offsite power with a single failure in the turbine driven pump train requires operator action to provide water to the steam generators.

(2) For a loss of main feedwater (or loss of all reactor coolant pumps) while performing surveillance test on one train, it would require operator action to realign the train being tested to provide flow to the steam generators.

(3) We don't know if there are single failures in the ICS that could cause loss of both main and auxiliary feedwater or both trains of auxiliary feedwater.

(4) We are not certain that each train of auxiliary feedwater has the capacity assumed in the generic LOCA analysis. R. C. Jones of B&W informed us on April 22, 1979 that the analysis assumes 500 gpm per steam generator (1000 gpm total) at 1050 psig. We need the pump head curves to evaluate this.

Normal Feedwater

2 turbine driven pumps with steam sources from (1) reheat steam; (2) main steam; (3) auxiliary steam. Shutoff head = 2750 ft. No strainers in feedwater (FW) system. No automatic bypasses for condensate demineralizers or feedwater heaters. Feedwater is shut off to the faulted steam generator when its steam pressure <435 psig.

Auxiliary Feedwater Sources

Normal supply: condensate storage tank (seismic category 1); first backup supply: canal (non-seismic); second backup: reservoir (non-seismic). There is a manual switchover from normal to backup that takes approximately 5 minutes.

Auxiliary Feedwater (AFW) Pumps

Two pumps - 1 motor driven and 1 with both a motor and a turbine driver, 840 gpm each. Shutoff head, with steam 3050 feet, with motor 3100 ft.

AFW Pump Drives

Steam supplied from main steam lines. The motors are on Class 1E power supplies. Steam driven pump has been demonstrated operable with steam pressure to the turbine drive as low as 213 psig.

AFW Pumps Auto Start

Both pumps start on either of the following:

(1) Loss of both main feedwater pumps as sensed by discharge pressure; each main FW pump <850 psig.

(2) All reactor coolant pumps off as sensed by the power monitor.

The turbine driven pump only also starts on Safety Features Actuation Signal (SFAS). Electrical power to all initiating signals is from Class 1E sources.

Automatic AFW Pump Trips

Motors: electrical faults (breaker). Steam turbine: overspeed.

AFW Indication

Motors: on-off lights, ammeters.
Steam supply valve position. (3 at separate control room locations)

Level Control

On loss of main FW pumps, ICS controls at 30 inches. On loss of all reactor coolant pumps, ICS controls at 318 inches. Operating procedures and practice require operator to maintain these levels using manual control if ICS fails to do so. On SFAS, the AFW flow control valves are bypassed, delivering full flow from AFW pump(s) to the steam generators. (Only the turbine driven pump starts automatically on SFAS.)

Independence of AFW Trains

Appear to be independent with three exceptions:

(1) They have a common suction source (seismic category 1 condensate storage tank).

(2) Cross-tie valves between the discharges are normally open (remote manual MOV's from Class 1E power supply).

(3) ICS inputs to both flow control valves.

Effect of Surveillance Test on System

To test one system, the discharge cross-tie valve and flow control valve are closed from the control room. Operator action would be required to get AFW to that steam generator if auto demand signal was received.

Common Mode Failures That Would Cause Loss of Main FW and AFW

The ICS is not Class 1E. There may be single failures that would cause the main FW flow control valves and the AFW flow control valves to close and remain closed. (ICS does not inhibit SFAS controls.)

Seismic Event

Only effect on AFW system would be that if offsite power were lost as a result of the earthquake, only one AFW pump would auto start on demand. The operator would have to manually start the motor driven pump on the diesel generator.

Loss of Offsite Power

Would cause almost immediate loss of both main FW pumps. Only the steam driven AFW pump would start automatically. Operator action would be required to start the motor driven pump on the diesel generator.

Loss of Offsite Power with Single Failure

Worst identified single failure would be loss of steam driven AFP. This would require operator action to restore AFW by starting motor driven pump. Questions on ICS - Have not investigated whether single failure can cause both AFW flow control valves to close.

AFW System Design Response to LOCA

When SFAS is initiated, the turbine driven AFW pump is started (regardless of whether main FW pumps or reactor coolant pumps are tripped). SFAS also opens bypass valves around the AFW flow control valves, thereby allowing the AFW pump to put ≈420 GPM into each steam generator. When steam generator level exceeds 30" (or 318" if operator has tripped RCP's), the auxiliary FW flow control valves are closed by the ICS.

Alternate Cooling Mode Without Main FW or AFW

Nuclear Service Cooling Water System.

APPENDIX L

COMMENTS ON OCONEE FEEDWATER SYSTEMS

Introduction

These comments were compiled during the week of April 15, 1979 from information in the FSAR and from telecons with the licensee.

Summary

(1) Seismic event could cause loss of all 3 units' emergency feedwater pumps.

(2) Several scenarios could result in feedwater not being supplied to the steam generators for 10 minutes or longer while operator manually realigns systems from other units or the auxiliary service water pump.

(3) Auto start signal is not single failure proof or seismic Category 1.

(4) There is only one EFW train per unit. R. C. Jones of B&W informed us on April 22, 1979 that the generic LOCA analysis assumes 500 gpm per steam generator (1000 gpm total) at 1050 psig. Apparently this one train does have that capacity; however, there is no redundancy.

(5) EFW injection valves are powered by non-Class 1E batteries.

(6) Technical specifications don't have operability requirements for other units' EFW systems.

Normal Feedwater

Two turbine driven main FW pumps with steam sources from (1) extraction steam; (2) main steam; (3) auxiliary steam. Shutoff head = 1253 psia. There are suction strainers for the hotwell pumps. The condensate demineralizers are automatically bypassed by air-operated valves (fail open) on high differential pressure across the demineralizers (40 psi). There is no automatic action to isolate a staem generator on break of main steam or feedwater lines.

Emergency Feedwater Sources

Normal supply: upper surge tank; first backup: main condenser hotwell; second backup: other units' upper sruge tanks (all sources non-seismic category 1). Switchover from normal to first backup is remote manual and requires approximately 1 minute.

Emergency Feedwater (EFW) Pumps

One pump per unit - turbine driven. Capacity = 1080 gpm at 1050 psig. Shutoff head = 1465 psia.

EFW Pump Drive

Steam supply to turbine driver is from main steam. Pump will operate with steam/pressure to drive at least as low as 300 psig.

EFW Pump Auto Start

(1) Loss of both main FW pumps as detected by low header discharge pressure <750 psig or by main FW pump turbine stop valve position on both pumps.

(2) EFW pump does not start on SFAS.

(3) Auto-start signals are from non-Class 1E sources.

Automatic EFW Pump Trips

(1) Overspeed

(2) Low hydraulic pressure

EFW Indication

(1) Pump discharge pressure

(2) Flow

Level Control

On loss of main FW pumps, the ICS controls steam generator level at 25". On loss of all reactor coolant pumps, the ICS controls level at approximately 260". Operating procedures and practice require operator to maintain these levels using manual control if the ICS fails to do so.

Independence of EFW Trains

Not applicable: only 1 train. Time required to align EFW from another unit is 10 minutes or longer.

Effect of Surveillance Test on System

Close manual block valves. Would require operator to reopen manual valves and close recirc valve to get EFW to steam generators if demanded during surveillance test.

Common Mode Failures That Would Cause Loss of Main FW and EFW

ICS is not Class 1E. There may be single failures that would cause the control valves that normally would feed both main FW and EFW to the steam generators to close. Operator action would be required to open an air operated valve in a line which bypassed the flow control valves.

Seismic Event

It appears that a seismic event could fail all three units' EFW pumps because of their location in a non-seismic Category 1 building, and fail all sources of suction for the EFW pumps.

Loss of Offsite Power

Could cause almost immediate loss of both main FW pumps. The EFW pump would start automatically if main FW pumps tripped.

Loss of Offsite Power with Single Failure
Assume single failure is the EFW pump for that unit. It would require operator at least 10 minutes to get water to the steam generators by manually realigning part of the EFW flow from the other units or to manually start the auxiliary service water pump.

AFW System Design Response to LOCA
None.

Alternate Cooling Mode Without Main FW or EFW
Auxiliary service water pump. One pump for the site. 3000 gpm. at 75 psig. Shutoff head = 100 psig. Must be started manually. Takes suction from circulating water inlet line. Located in seismically-designed auxiliary building. Powered from Class 1E source.

APPENDIX M

COMMENTS ON DAVIS-BESSE UNIT 1 FEEDWATER SYSTEMS

Introduction

These comments were compiled during the week of April 15, 1979 from information in the FSAR and from telecons with the licensee.

Summary

(1) A single failure in an AFW train would require operator action to provide water to both steam generators.

(2) Apparently, each train of the AFW system has less capacity than assumed in the LOCA analysis. (R. C. Jones of B&W informed us on April 22, 1979 that the analysis assumes 500 gpm per steam generator (1000 gpm total) at 1050 psig.)

(3) Suction strainers on both AFW pumps could possibly be blocked following seismic event by debris from the common, non-seismic category 1 suction source.

Normal Feedwater (FW)

Two turbine driven pumps with steam supplies from (1) reheat steam, (2) main steam, (3) auxiliary steam. Shutoff head = 2560 ft. Condensate pumps have suction strainers. Main FW is isolated from both steam generators when one is faulted (steam and feedwater rupture control system). This system also starts the auxiliary FW pumps and aligns both to the good steam generator.

Auxiliary Feedwater Sources

Normal supply: condensate storage tank (non-seismic category 1): first backup supply: deaerator (non-seismic category 1); second backup: fire water system (non-seismic category 1); seismic category 1 supply: service water pump discharge. Auto transfer of either pump's suction to the seismic category 1 source when on any of the other sources and get low suction pressure. (Redundant Class 1E pressure switches.)

Auxiliary Feedwater (AFW) Pumps

Two pumps, both turbine driven. Each 1050 gpm at 1050 psig (250 gpm of this is recirc flow each pump). Shutoff head = 3150 ft.

Auxiliary Feedwater Pump Drives

Steam supplied from the main steam lines upstream of MSIV's. Pumps demonstrated operable down to T = 280°F (Psat = 50 psia).

AFW Pumps Auto Start

Both AFW pumps start on any of the following signals:

(1) Steam pressure greater than feedwater pressure by 170 psi (for feedwater break or loss of FW pumps).

(2) Steam generator low level.

(3) Loss of all reactor coolant pumps (sensed by RPS power monitor).

(4) Low main steam line pressure (600 psig).

AFW Pump Auto Trips

Either pump trips on:

(1) overspeed

(2) low suction pressure

(3) low steam (to turbine drive) after ~~25 seconds~~

AFW Indication

(1) Discharge pressure each pump.

(2) Speed indication each pump.

Level Control

Auto essential level control system controls at 120". However, operating instructions require operator to control at 35 inches if there is no SFAS (until dual level setpoint is installed).

Independence of AFW Trains

Appear to be independent with the exception of:

(1) The suction source (non-seismic condensate storage tank). However, each pump auto transfers to seismic category 1 redundant sources on low suction pressure.

Effect of Surveillance Test on System

No effect on normal valve lineups. A pump is started and the mini-flow "recirc" is aligned to the sump as usual. If a demand signal is received during the surveillance test, the injection valves open and normal emergency injection begins.

Seismic Event

(1) Only effect would be loss of the normal suction source to both pumps. The suction for each pump automatically transfers to the seismic category 1 source on low suction pressure.

(2) The seismic event could possibly damage the condensate storage tank in a manner that could cause blockage of the suction strainers on both AFW pumps.

Loss of Offsite Power

Could cause almost immediate loss of both main FW pumps. Both AFW pumps would start automatically after diesel generators are started.

Loss of Offsite Power with Single Failure

Worst identified single failure is loss of one train of AFW. Operator action is required to deliver water to both steam generators from one AFW pump (open cross-tie MOV's from control room).

AFW Design Response to LOCA

Does not start directly from SFAS. LOCA analysis assumes AFW flow. The AFW pumps would be started by different signals on many accidents which initiate SFAS.

Alternate Cooling Mode Without Main FW or AFW

Startup FW pump 250 gpm at 1050 psig.

APPENDIX N

COMMENTS ON ARKANSAS UNIT 1 FEEDWATER SYSTEMS

Introduction

These comments were compiled during the week of April 15, 1979 from information in the FSAR and from telecons with the licensee.

Summary

(1) There is no auxiliary steam supply to the main feedwater pump turbines. If both emergency feedwater pumps inoperable, must rely on auxiliary feedwater pump to get to cold shutdown. Auxiliary feedwater pump is not seismic category 1 and is not Class 1E.

(2) Several components in the emergency feedwater system are not powered by a Class 1E source. The pump motor is not normally powered by a Class 1E source but can be manually aligned to a Class 1E source. Additionally, some of the system instrumentation is not Class 1E.

(3) For any demand sequence, a single failure of the turbine driven EFW pump would require operator action to get emergency feedwater into the steam generators because the motor driven pump does not auto-start by design.

(4) It is questionable whether each train of emergency feedwater has the capacity assumed in the generic B&W LOCA analysis. (R. C. Jones of B&W informed us on April 22, 1979 that the analysis assumes 500 gpm per steam generator (1000 gpm total) at 1050 psig.)

(5) We don't know if there are single failures of the ICS that could cause loss of both emergency FW trains or simultaneous loss of main and emergency feedwater.

(6) The emergency feedwater pumps do not directly start on ECCS initiation signal. (However, the turbine driven EFW pump would be started by other signals for many of the accidents which initiate ECCS signal.)

(7) Portions of the auto start instrumentation are not redundant. Concern is for single failures.

(8) The pressure switch on EFW pump suction that alerts operator to switch to backup suction source (of water) is not redundant.

Normal Feedwater (FW)

Two turbine driven pumps with steam sources from (1) reheat steam, (2) main steam. Shutoff head = 1090 psig. The condensate pumps have suction strainers. No automatic bypasses around demineralizers or FW heaters. The Steam Line Break Instrumentation and Control (SLBIC) system isolates main FW to both steam generators if the pressure in either is less than 600 psig.

Emergency Feedwater (EFW) Sources

Normal supply: condensate storage tank (non-seismic Category 1); backup source: service water pump discharge (either of two) (seismic Category 1). Switchover to backup source is by remote manual MOV's and can be done in seconds from control room. However, the pressure switch which gives low suction pressure alarm is not redundant or Class 1E. The valves which must be realigned are Class 1E.

EFW Pumps

Two pumps, one turbine driven and one motor driven. Each pump 780 gpm at 1112 psig. Shutoff head unknown.

EFW Pump Drives

(1) Motor - not normally powered from a Class 1E source but the licensee is currently evaluating this possibility.

(2) Turbine - supplied by main steam upstream of MSIV's.

EFW Pumps Auto Start

(1) Motor - no auto starts

(2) Turbine - auto starts on any of the following signals: (a) SLBIC (steam generator pressure less than 600 psig). This is a Class 1E signal; (b) loss of FW (as sensed by governor latch on both main FW pumps) coincident with low discharge pressure of the "auxiliary" FW pump (signal from ICS); and (c) loss of all reactor coolant pumps (sensed by breaker position). Note: does not start on SFAS.

(3) With exception of SLBIC, the start signals are not Class 1E.

Automatic EFW Pump Trips

Motor - electrical faults
Turbine - overspeed

EFW Indication

Discharge pressure each pump.

Level Control

On loss of main FW pumps, ICS controls level at 20 inches in one steam generator; 24 inches in the other. On loss of all reactor coolant pumps, the ICS controls level at 50% on the operating range (approximately 300 inches). Operating procedures call for the operators to manually control level to control reactor coolant system temperature.

Independence of EFW Trains

Appear to be independent with the exception of the following:

(1) Normally open cross-ties valves between discharge lines.

(2) Common normal suction source (non-seismic Category 1 CST) and suction line.

(3) Common suction line from backup source (service water).

(4) Non-redundant pressure switch that alerts operator to switch suctions on loss of normal source.

(5) ICS inputs to flow control valves of both trains. There may be single failures of the ICS that would cause valves in both trains to close.

Effect of Surveillance Test on EFW System

Operator opens manual recirc valve on train being tested. Injection valves are normally closed. If EFW is needed, operator must close recirc valve to align full EFW flow to the steam generators.

Common Mode Failures that Would Cause Loss of Main FW and Emergency FW

The ICS is not Class 1E. Neither is some of the EFW system instrumentation. Failure modes may exist which would cause the main FW valves to close and prevent the EFW injection valves from opening. Operator action would be required to open the EFW injection valve bypass valves (MOV's).

Seismic Event

A seismic event could cause loss of the normal suction source. Debris from the non-seismic category 1 condensate storage tank could cause damage to both emergency feedwater pumps if it entered both pumps. (This is not unique to this facility.)

Loss of Offsite Power

Could cause almost immediate loss of both main FW pumps. Only the turbine driven EFW pump starts automatically. Operator action would be required to start the motor driven pump on the diesel generator. (Operator action required to start motor driven pump with offsite power available also.)

Loss of Offsite Power with Single Failure
Worst identified single failure is loss of the turbine driven EFP train. This would require operator action to restore EFW by starting motor driven pump. Questions on ICS: We have not investigated whether single failure can cause both EFW flow control valves to close.

EFW System Design Response to LOCA
System will not start automatically on ECCS initiation. LOCA analysis assumes flow. (However, the turbine driven EFW pump would be started by other signals for many of the accidents which initiate ECCS signal.)

Alternate Cooling Mode Without Main FW Pumps or EFW Pumps
Auxiliary feedwater pump. 1150 gpm at 1000 ft.

APPENDIX O

CRYSTAL RIVER, UNIT 1

FLORIDA POWER CORPORATION

Response to Item 2 of I&E Bulletin 79-05A

Each Licensee for a B&W operating plant was requested to respond to Item 2 of IE Bulletin 79-05A. Item 2 was stated as follows:

> "Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item."

Trip: 79-1
Date: January 6, 1979
Event: Excessive Cooldown Rate Due to Stuck FW Block Valve
Initial Conditions: 71% RPT, 595 MWe

DESCRIPTION

At 0242 on January 6, 1979, the turbine tripped and feedwater block valve FWV-30 stuck in an open or partially open position. Control room operators took action to shut the main feedwater cross-connect valve, FWV-28, and trip feedwater pump "A". At this point feedflow was stopped to "A" steam generator and "B" feedwater pump was supplying "B" steam generator. When steam supplying the "B" feedwater pump turbine automatically shifted from reheat steam to main steam (a normal occurrence due to loss of reheat steam pressure when the main turbine tripped), the feedflow to "B" steam generator decreased and T_{ave} increased to 600°F. Reactor coolant pressure peaked at 2255 psi when the electromatic pressurizer relief valve opened momentarily. Pressurizer level peaked at 307 inches. The reactor was manually tripped by the control room operator and the turbine driven emergency feedwater pump was started to restore feedwater flow. FWV-30 was found to be stuck on its backseat and was taken off the backseat manually and closed. FWV-28 was reopened. The cooldown transient, which resulted when the reactor was tripped and emergency feed initiated, resulted in a loss of pressurizer level indication (low) for approximately 2 minutes. Reactor coolant system pressure decreased to 1600 psi during the same time frame and T_{ave} decreased to 521°F. At 0615, FWV-30 was proven operable by surveillance procedures and auxililary steam had been brought in to restart normal feedwater pumps. Plant parameters of interest are shown in the attachments.

SIGNIFICANT DEVIATIONS

There were no deviations from expected performance except for the failure of FWV-30 to shut. This failure had no impact on safe shutdown of the plant since feedflow could be stopped by shutting FWV-28 and tripping "A" feedwater pump. Redundant emergency feedwater systems were available and operable.

Simpson (NRC10)
D63

Trip: 77-33
Date: April 16-23, 1977
Event: Shutdown From Outside Control Room Test
Initial Conditions: 15% RTP

DESCRIPTION

The shutdown from outside the control room test simulated an emergency situation requiring evacuation of the control room. All plant controls were left in automatic unless remote indication required taking them into manual modes of operation. The purpose of the test was to demonstrate that the unit could safely be brought to hot standby conditions from outside the control room.

The test was started from 15% power. Letdown flow was stopped and the control room evacuated by the normal shift complement of operators. The operators manned their remote shutdown stations as shown in the attached table. A complete second set of operators was left in the control room to assume plant control if the test failed. The reactor was tripped remotely and the plant allowed to come to hot standby automatically. The operators outside the control room were to take control of various equipment if it was not performing adequately in automatic.

On April 16, 1977, the first run at shutdown from outside the control room was attempted and aborted after approximately 18 minutes due to feedpump ΔP oscillations. Main feedwater pump speed control had been shifted to hand by the operators in the control room early in the test. After the reactor trip, high leakage through the startup valves resulted in overfeeding both steam generators. The test was terminated due to loss of steam generator level control and greater than desired cooldown of the primary plant. As a result of this experience, the plant emergency procedure for shutdown from outside the control room was changed to require tripping the main feedpump remotely. This would allow the steam driven emergency feedwater pump to start and take over steam generator feed requirements.

On April 22, 1977, the test was repeated with the above modifications. This run was stopped after approximately 9 minutes due to low levels in both steam generators. Subsequent investigation revealed that initial conditions for steam pressure to the steam driven emergency feedwater pump were not met. This resulted in both steam generators being dry* until flow was established by the electrical driven emergency feedpump. The plant emergency procedure was modified to require the operator to check the steam driven pump and, if that is not operating properly, start the electrical driven pump.

* The steam generators were designed for 20 allowable thermal cycles equivalent to being boiled dry.

Simpson (NRC10)
D63

Trip: 77-31
Date: April 21, 1977
Event: Partial Loss of Power to the ICS
Initial Conditions: 46% RTP, 323 MWe

DESCRIPTION

At 0430 on April 21, 1977, the "X" power supply to the integrated control system (ICS) was lost, resulting in the following events:

A. The ICS saw an erroneous zero reactor coolant flow condition (no reactor coolant pumps running) and signaled the feedwater system to maintain steam generator level at 50% in the operating range.

B. An ensuing increase in turbine header pressure caused all turbine bypass valves and atmospheric dump valves to open.

C. The main feedwater block valves went shut and emergency feedwater block valves opened in response to ICS demand.

D. As a result of decreased steam flow to the main turbine, Megawatt electric output decreased to the point where the control room operators opened the generator output breakers and tripped the turbine.

E. The control room operator manually opened the startup block valves and maintained minimum required feedwater flow.

At this point, power was restored to the ICS when the electricians replaced a blown fuse. A normal plant recovery followed. Minimum and maximum pressurizer levels attained during this transient were 40 inches and 270 inches respectively. Other plant parameters of interest are shown on the attachments.

SIGNIFICANT DEVIATIONS

There were no deviations from expected performance.

OTHER COMMENTS

An earlier transient of this type was experienced during reactor trip 77-13 on March 2, 1977, when Inverter "B" tripped, causing a similar loss of ICS power. There was a concurrent loss of a main feedwater pump necessitating use of the emergency feed system for steam generator level control.

Simpson (NRC10)
D63

On April 23, 1977, the test was run successfully. The control room was evacuated with the plant at 15% power. The running main feedpump was tripped remotely (which trips the main turbine). The reactor, however, was not tripped until at least one minute later, resulting in low steam generator levels. The operators started the electric-driven feedwater pump, took manual control of both feedwater startup valves and restored level in both steam generators. Twenty minutes into the test, an operator remotely added water to the makeup tank, otherwise the plant remained in a fully automatic mode of operation and came to a hot standby conditon. The test was allowed to run for thirty minutes to verify that the operators outside the control room had complete control of the plant. At this time, plant parameters were at or near their final steady state values and the test was ended.

Although level and feedflow indication did not show zero, post test analysis indicated that the steam generators were dry in about seven minutes. This occurred because of a combination of problems with reference legs, flows, and/or calibration errors. This could be verified by noting that during the dry period, main steam pressure was below the saturation pressure and recovered as soon as feedflow was re-established.

Charts of significant plant parameters are shown in the attachments. Worse case transients were experienced during the aborted tests on April 16 and April 22. Test results on April 23 were acceptable.

SIGNIFICANT DEVIATIONS

Deviations from expected performance were experienced on Apcil 16 and April 22 as discussed above. Corrections were made to the emergency procedure governing this evolution and the test was completed satisfactorily.

The test proved that the reactor can be brought to and maintained in a safe hot standby condition from locations outside the control room by the normal shift complement of operators.

Trip: 77-35
Date: April 23, 1977
Event: Loss of Offsite Power Test
Initial Conditions:

The Loss of Offsite Power Test consisted of two (2) parts. The first part approximated a total plant blackout from 15% reactor power; the second part was performed from a shutdown condition and verified a diesel generator's ability to start and pick up certain vital loads.

DESCRIPTION

With the plant at 15% power, the reactor and startup transformer were simultaneously tripped. This immediately reduced total plant power to the emergency batteries and the above mentioned diesel generator. The 3A diesel generator was timed as it started, came up to speed and picked up certain pre-determined loads on its ES Bus. After allowing the plant to operate in this condition for fifteen minutes, the startup transformer was re-energized. Loads considered necessary to allow plant equipment to survive the test were shifted from the 3B to 3A diesel generator. The 3B diesel was then stopped and the startup transformer again tripped. This allowed the timing of the 3B diesel as it came up to speed and picked up its pre-selected loads. At that point, the test was complete. However, it was observed that there was a large imbalance in feedflow. Subsequent investigation and evaluation revealed the following sequence of events:

EVENT

Tripped power, both feedwater pumps stopped, and all feedwater flow was lost.

Steam driven emergency feedwater (EFW) pump automatically up to speed and feeding both steam generators.

Operator started electric-driven emergency feedwater pump. "A" steam generator is being preferentially fed, but both are getting water.

Operator stopped steam-driven EFW pump. "A" steam generator is being filled (startup level indication), "B" steam generator startup and operating range level indicators are both apparently at the bottom of their range. This can be verified by noting that loop "B" hot and cold leg temperatures indicate that little or no heat transfer is occurring through "B" loop. (Figure 4.15-1)

"B" loop startup feedwater flow indication is at the bottom of its range. (This was confirmed by a zero calibration check of the instrument made on 5/11/77. This check showed the zero had shifted to 1.5×10^5 Lbm/Hr. A similar check of "B" startup flow made on 5/11/77 showed its zero shifted to $.95 \times 10^5$ Lbm/Hr.)

Trip: 77-48
Date: October 26, 1977
Event: Loss of Inverter "A"/Loss of Vital Bus "A"
Initial Conditions: 100% RTP, 838 MWe

DESCRIPTION

At 0427 on October 26, 1977, Inverter "A" tripped causing a loss of power to Vital Bus "A". As a subsequent result, the main turbine tripped, Feedwater Pump "A" tripped and Feedwater Pump "B" ran back to minimum speed. Excess heat production resulted in high reactor coolant system pressure and a reactor trip. The control room operator started both emergency feedwater pumps. Atmospheric dump valves, which opened to relieve excess steam from the steam generators following turbine trip, failed to close at the expected design setpoint but did close at a lower pressure. With the high steam generator feedrate and the late closing of the atmospheric steam dumps, an excessive rate of cooldown was experienced. Pressurizer level, decreasing due to reactor coolant system cooldown, was maintained in the indicating range using manual control of the high pressure injection system. Minimum and maximum pressurizer levels achieved during the transient were 35 inches and 245 inches respectively. Other plant parameters of interest are shown on the attachments.

SIGNIFICANT DEVIATIONS

The only deviation from expected performance was the failure of the atmospheric dump valves to close at the prescribed design setpoints. Although this failure occurred and contributed to an excessive reactor coolant system cooldown rate, it was not considered to be a critical failure since the dump valves are only sized to pass 7.5% of rated steam flow. Even if the valves stuck open for the entire transient, the cooldown rate, which would have been experienced, would be insignificant when compared to a main steam line break accident. Each atmospheric dump valve can be manually isolated by an associated upstream root valve.

Simpson (NRC10)
D63

Operator restarted steam driven EFW pump, started feeding "B" steam generator again.

Operator opened parallel valve (EFV-162) in the feedwater train to "A" steam generator by mistake.

Operator shut EFV-162 and opened a parallel valve (EFV-161) in the feedwater train to "B" steam generator.

"B" steam generator filling, on its way to recovery

SIGNIFICANT DEVIATIONS

The plant should have responded automatically by starting the steam-driven emergency feedwater pump within 1 minute and filling each steam generator to 50% on the operating range. However, with one pump feeding both steam generators any imbalance in steam pressure will result in one generator getting more feedwater than the other. After primary flow has coasted down (approximately two minutes), the cold feedwater cools the primary water in the steam generator. This results in a continuing lowering of the pressure in the steam generator already being fed, thus increasing its feedflow. This feedback effect allows one steam generator to be underfed until the other one reaches a level of 50% at which point its feed valve will shut. The emergency procedure for loss of offsite power has been changed to require the operator to monitor levels and keep the feedflow shared between steam generators.

Trip: 79-2
Date: January 17, 1979
Event: Turbine Building Flooding/Loss of Feedwater
Initial Conditions: 100% RTP, 848 MWe

DESCRIPTION

At 1010 on January 17, 1979, a solenoid failure was experienced on CWV-2 (inlet seawater block valve to secondary services heat exchanger "A") causing it to fail open. The associated secondary services heat exchanger was opened at this time for cleaning. When CWV-2 opened, sea water flowed out of the open heat exchanger onto the 95 ft. elevation of the Turbine Building. Control room operators were alerted by flooding reports from maintenance personnel on the scene. Attempts were made to close CWV-2 but were unsuccessful. At 1015, the circulating water pump, which was the source of flooding, was secured. Input of seawater stopped but water already in the building continued to flow across the floor. At 1018, both condensate pumps tripped due to water contacting and shorting local control switches. At 1020, the main turbine was manually tripped. At 1021, feedwater booster pumps and main feedwater pumps tripped due to a low deaerator level. At 1022, the reactor was manually tripped due to increasing pressurizer level and reactor coolant system pressure.

Maximum reactor coolant pressure was maintained below 2270 psi. The turbine-driven emergency feedpump started automatically. At 1030, the control room operator started the motor-driven emergency feedwater pump and secured the turbine-driven pump. At 1040, the plant began to recover from the transient. Reactor coolant pressure reached a minimum of 1760 psi and was restored to a stable reading of 2150 psi by 1100. At 1110, electrical power to the condensate pumps was restored. During the transient, pressurizer level was maintained between 80 inches and 300 inches. Plant parameters of interest are shown on the attachments.

SIGNIFICANT DEVIATIONS

This transient was controlled by the emergency feedwater system within the intended design envelope. There were no deviations from expected performance. The initiating event (i.e., seawater contacting and shorting out local condensate pump controllers) was corrected by relocating the local condensate pump controllers to higher elevations above floor level.

Simpson (NRC10)
D63

Trip: 79-3
Date: January 30, 1979
Event: Loss of Feedwater Flow to the "B" OSTG
Initial Conditions: 100% RTP, 845 MWe, Full ICS Auto.

DESCRIPTION

At 0515 on January 30, 1979, a reactor trip occurred due to a loss of feed from the "B" main feedwater pump. The feedwater pump did not actually trip but F.W. flow had reduced significantly in the "B" loop. The F.W. crossover valve, FWV-28, did not open since FWP-2B did not trip. This caused a loss of feedwater to the "B" steam generator which resulted in excessively high reactor coolant pressure and a degradation of OTSG header pressure. The turbine reacted to the reduced header pressure by rapidly reducing MWe in an attempt to regain plant stability. The control system reacted to reduction in MWe and commenced running the plant back to a lower power level. A short time into the runback the operator took action to restore F.W. flow to the "B" OTSG by opening FWV-28. This resulted in overfeeding the OTSG's for the immediate power level which induced a rapid RCS cooldown and outsurge of the pressurizer. The resultant reduction of RCS pressure tripped the reactor on low R.C.S. pressure. The excessive feed rate and subsequent cooldown was terminated by the ICS function of closing all F.W. control valves following the reactor trip. RCS pressure degraded to slightly less than 1700 psig but high pressure injection was not actuated. Pressurizer level maximum and minimum achieved during this transient were 290 in. and 38 in. respectively.

SIGNIFICANT DEVIATIONS

There were not significant deviations from expected system performance during this transient.

Simpson (NRCIC)
D63

APPENDIX P

RANCHO SECO, UNIT 1

SACRAMENTO MUNICIPAL UTILITY DEPARTMENT

Response to Item 2 of I&E Bulletin 79-05A

Each Licensee for a B&W operating plant was requested to respond to Item 2 of IE Bulletin 79-05A. Item 2 was stated as follows:

> "Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item."

Item 2

Review any transients similar to the Davis-Besse Event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility. If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item.

Response to Item 2

The District has reviewed transients at Rancho Seco Unit No. 1 in order to determine any having similar elements to the chronology of events at Three Mile Island Unit 2 and Davis-Besse Unit 1. We have not found any transients which are similar, however, we have reviewed one transient with a cooldown which resulted in operation outside the Technical Specification pressure-temperature limits. This has been reported previously as a reportable occurence as follows:

RO 78-01 March 30, 1978 and March 31, 1978

This event was analyzed by B&W, the NSSS vendor. The analysis concluded no damage occurred which would affect further operation of Rancho Seco. The District's Management Safety Review Committee evaluated this event and has approved the following corrective actions to be implemented at Rancho Seco Unit No. 1 by the end of the next refueling outage:

1. A nonconducting foam rubber plug has been developed to insert in the back lighted push button module whenever the lamp bulb section of the module is lifted out.

2. Testing has been performed on the existing NNI-Y power supply system to determine the trip point of the power supply monitors, the time delay of the trip circuit breakers, the current limiting point of the power supplies, the transfer voltage point of the AC automatic transfer switch, the performance characteristics of the power supply fuses, and verification of original trip conditions on the power supplies.

3. Lower rated fuses will be installed in each group of modules where analysis has shown this can be done safely.

4. The power supplies will be improved to minimize the number of components affected by a power failure.

5. Procedures have been changed and instrumentation will be installed to provide control room indication of the critical NNI-X or NNI-Y signals.

The safety significance of this transient is due only to the structural integrity of the reactor coolant system and possible equipment damage. Neither condition posed any threat to the fuel. Voids were not formed. Pressurizer level did decrease below visible indication upon safety features actuation but was restored with high pressure injection. Subcooling in the reactor coolant system (excluding the pressurizer) was maintained at a minimum of 35°F. Reactor coolant flow was maintained with a minimum of one pump per loop at all times during the transient.

APPENDIX Q

OCONEE, UNITS 1, 2, AND 3

DUKE POWER COMPANY

Response to Item 2 of I&E Bulletin 79-05A

Each Licensee for a B&W operating plant was requested to respond to Item 2 of IE Bulletin 79-05A. Item 2 was stated as follows:

> "Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item."

Response

Based on initial information relative to the recent Three Mile Island Unit 2 occurrence, Duke Power Company initiated on March 29, 1979 a review regarding similar transients at Oconee Nuclear Station. On March 30, 1979, a summary of this early review was provided verbally to NRC/OIE, Region II. Subsequently, the review of Oconee transients was continued, particularly to address additional TMI-2 information as such became available. At the present time, Oconee transients considered applicable for purpose of the subject review are categorized as follows:

(a) Feedwater Transients Resulting in Reactor Trip
(b) Pressurizer Relief Valve Stuck Open
(c) Loss of Offsite Power

With regard to feedwater transients resulting in reactor trip, Oconee has experienced approximately 42 such incidents as tabulated below:

UNIT	YEAR						
	1973	1974	1975	1976	1977	1978	1979
1	11	1	3	3	2	2	0
2	4	1	4	1	0	3	0
3	N/A	2	1	1	0	2	1

As can be seen, the greatest number of these transients (per unit, per year) occurred during the initial operation of Unit 1 in 1973. Subsequent experience is consistent with classification of this event as one of moderate frequency.

Eleven of the above 42 incidents occurred at or near full power (Unit 1-7, Unit 2-2, Unit 3-2) and demonstrate the ability of the Oconee units to safely respond to such events. Several feedwater transients which resulted in reactor trip have been identified however as involving deviations from expected performance. These and transients in categories (b) and (c) are summarized, in chronological order of occurrence, below:

(1) On January 4, 1974 while operating at 75% full power, Unit 2 tripped due to a loss of off-site electrical power. The reactor coolant pumps (RCP) tripped, and natural circulation cooling was established. RCP seal injection and component cooling were lost for approximately 31 seconds at the

time of the trip. Both were again lost for 15 seconds about 25 minutes after the trip. Subsequently, because pressurizer level was increasing due to excessive makeup flow, an attempt was made to initiate letdown flow, but no flow was indicated. High Pressure Injection (HPI) was secured, and all seal return valves closed in order to reduce makeup volume. A leak was discovered which was the result of a blown gasket on the upstream side of the letdown flow indicator. The letdown line was isolated to control leakage, and the emergency makeup valves were closed. During this time, HPI was turned on again for approximately a minute, then secured again. When the seal return valves were closed, RCP seal cavity pressure went to system pressure. Seal injection flow resumed about 20 minutes later when HPI was once again started.

No design or Technical Specification limits were exceeded during this transient, and the event was not considered to have any safety significance. Hardware and procedural changes were made, however, to provide better monitoring and control during future similar incidents.

(2) On June 13, 1975 while Unit 3 was operating at 15% full power, a feedwater transient resulted in an RCS pressure transient which resulted in the pressurizer power operated relief valve (PORV) opening. The PORV failed to close when pressure decreased and the subsequent RCS depressurization was terminated by closure of the PORV block valve by operator action. Additional information regarding this incident is provided in Mr. William O. Parker's letters of June 27, 1975 and August 8, 1975 to Mr. Norman C. Moseley, Director, NRC/OIE, Region II - see Enclosure 2-1.

(3) On July 12, 1976 while Unit 2 was being shut down in order to repair a main turbine steam leak, the ICS induced an oscillation in feedwater parameters. The feedwater pumps tripped on low feedwater pressure, causing a turbine trip. The trubine trip caused RCS pressure to rise sufficiently to open the pressurizer PORV, relieving pressure to the quench tank. The quench tank rupture disc burst. The PORV reclosed properly when RCS pressure decreased. This RCS transient was of short duration and not observed by the operators who were responding to the turbine trip. The alarm typer, another source of plant equipment status, was out of service. The unit was shut down and turbine repairs were effected, but the quench tank rupture disc was not replaced since its rupture had not been noted. The unit was operated until July 27, 1976, when it was shut down to repair a reactor coolant pump. At that time the burst rupture disc was discovered and replaced.

No design or Technical Specification limits were exceeded during this transient, and the event was not considered to have any safety significante. Operations personnel were subsequently instructed, however, to observe quench tank instrumentation more closely following transients in order to note indications of high quench tank pressure or a burst rupture disc.

(4) On December 14, 1978, an electrical short in the Unit 1 ICS RCS average temperature (T_{ave}) recorder caused the temperature indication to be approximately 13°F low. To compensate for the low T_{ave} indication, the ICS initiated an increase in power (from approximately 98% full power), but operations personnel had been instructed not to allow power to increase above 99% full power until an earlier problem had been resolved. Therefore, manual control of the reactor was assumed, causing the ICS to switch T_{ave} control from the reactor master to the feedwater master. Feedwater flow decreased to compensate for the -13°F error in the ICS. Upon observing increasing hotleg temperature, decreasing reactor power, and decreasing feedwater flow, operations personnel placed the feedwater master in manual and began increasing feedwater flow. However, before the increasing RCS temperature could be corrected, the reactor tripped on high temperature. Feedwater flow was decreased as rapidly as possible, and the resulting high discharge pressure caused both feedwater pumps to trip. The emergency feedwater pump was started and ran until the feedwater pumps were reset and started. However, the levels in the two steam generators continued to decrease; level in the 1A steam generator reached a low of six inches, while steam generator 1B went dry. Operations personnel opened the feedwater valves and the emergency header block valves in order to feed the steam generators through the emergency feed header. Level was partially restored, although steam generator 1B level remained significantly lower than that of steam generator 1A. This was probably due to the failure of the 1B emergency header block valve to open fully. In order to increase the 1B steam generator level, the emergency feedwater pump was restarted and fed through the emergency header. RCS pressure dropped rapidly due to the quick cooldown of steam generator 1B, causing the feedwater pumps to trip on low suction pressure, and removing feedwater flow from steam generator 1A. Flow was re-established to that steam generator by lining up the emergency feedwater pump to feed it. HPI was initiated when an Engineered Safeguards actuation signal was received due to low RCS pressure. All ES components operated properly.

Additional information regarding this incident is provided in Mr. William O. Parker's letter of January 15, 1979 to Mr. James P. O'Reilly, Director, NRC/OIE, Region II - see Enclosure 2-2.

(5) On December 25, 1978, Unit 1 was at approximately 10% full power and increasing in power following a reactor trip when power to the ICS was lost as a result of blown fuses. When ICS power was lost, both feedwater pumps tripped. The emergency feedwater pump was started, but Control Room instrumentation indicated a discharge pressure of less than 100 PSIG. Personnel were dispatched to increase the discharge pressure to its normal range of 950 to 1000 PSIG. The pump indicated a discharge pressure of 600 PSIG, and it was later determined that the control room instrumentation required approximately five minutes to provide an accurate indication.

Approximately one minute after the feedwater pumps tripped, the reactor tripped on high RCS pressure. When ICS power was lost, the normal feedwater startup header valves began to close and the emergency header block valves opened. Level in steam generator 1A was restored, but 1B went dry. it appears that the block valve failed to open fully. The feedwater pumps were reset and restarted, and flow to the 1B steam generator resumed through the normal feedwater header. The steam generator was dry for approximately 15 minutes.

The reason the emergency header block valve failed to open fully has not been determined. The governor control valve on the emergency feedwater pump has been checked to assure that it is properly set. Operations personnel have been instructed as to actions to take to supply flow to the affected steam generator if flow cannot be established through the startup feed valve and auxiliary feedline immediately after the loss of main feedwater pumps. A procedural change, applicable for all units, has been made requiring operators to bypass the block valve in the event the block valve fails to open. The operator can, from the Control Room, operate one valve to provide emergency feed flow bypassing the block valve to the affected steam generator. The emergency feedwater pump discharge pressure instrument has been adjusted to decrease its response time. This event was not considered to have any safety significance.

APPENDIX R

DAVIS-BESSE, UNIT 1

TOLEDO EDISON ELECTRIC COMPANY

Response to Item 2 of I&E Bulletin 79-05A

Each Licensee for a B&W operating plant was requested to respond to Item 2 of IE Bulletin 79-05A. Item 2 was stated as follows:

> "Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item."

Response to Item 2

All transients that have occurred at DB-1 that have been initiated by either a loss of feedwater flow or excessive feedwater flow have been reviewed to determine if any significant deviations from expected performance occurred. During this review the following information became evident regarding the five similar transients discussed below:

a) Out of the five similar transients; found the first four occurred during the first year of operation prior to the time that the final tuning of the Integrated Control System (ICS) was completed. ICS controls the main feedpump turbine speed and the main feedwater control valves.

b) No offsite radiation releases resulted from any of these events.

The Davis-Besse Unit 1 event referenced in Enclosure 2 of IE Bulletin 79-05 occurred on November 29, 1977. This event was addressed in previous information provided to the NRC, reference Reportable Occurrence NP-32-77-20 on the Davis-Besse Unit 1 docket, dated December 12, 1977. At the time of the occurrence the Unit was in Mode 3. The loss of power aspect of this event is discussed in Reportable Occurrence NP-33-77-98 dated December 16, 1977. The corrective action modified the emergency procedure to preclude manual tripping of the generator main breakers on a turbine trip.

With respect to Item 3 on page 2 of Enclosure 2 to IE Bulletin 79-05, reference is made to "A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1." The Enclosure 1 referred to is a letter from L. E. Roe to R. W. Reid dated December 22, 1978, Serial No. 475. This letter analyzed postulated Davis-Besse Unit 1 transients resulting from the operator not controlling steam generator level at 35 inches in accordance with current operating procedures. The two overcooling transients examined are a loss of offsite power and a loss of feedwater. The loss of feedwater transient results in the greater volumetric contraction of the reactor coolant system because the forced coolant flow with reactor coolant pumps operating causes a faster rate of heat rejection to the steam generators.

On September 24, 1977 a depressurization of the Davis-Besse Unit 1 reactor coolant system occurred that contained some similar elements to the chronology of Enclosure 1 to IE Bulletin 79-05A. At the time, the Unit was in Mode 1 with power at 268 MWT with the turbine off the line. The details of this event are included in Supplement to Reportable Occurrence NP-32-77-16 dated November 14, 1977. System and equipment modification and testing actions are included in that report.

On December 11, 1977 Davis-Besse Unit 1 was tripped for the 40% reactor trip test. During recovery from the trip with the Unit in Mode 3 (power at 0 MWT), control of both auxiliary feed pumps was lost. Modifications were made to the controls and surveillance testing was modified to demonstrate operability. See Reportable Occurrence NP-33-77-110 dated January 3, 1978.

On April 29, 1978 Davis-Besse Unit 1 had one high pressure injection pump inject water for two minutes while the RCS pressure was below 1700 psig. The Unit was in the process of shutting down from 420 MWT for maintenance. The cause of the occurrence was the sensitivity of the feedwater controls while on three reactor coolant pump operation, and improper operator action in taking manual control of the feedwater. This resulted in overcooling the reactor coolant system. HPI actuation was according to design. Corrective action was completed per Reportable Occurrence NP-30-78-01, Letter No. 1-23, dated July 28, 1978.

On January 12, 1979 an accidental ground caused the loss of a 120 VAC essential bus due to an improper fuse in the 120 VAC switchgear. The loss of this 120 VAC essential bus caused a loss of level indication on steam generator (SG) 2. After the reactor tripped, the level in SG 2 fell low enough to cause a full Steam and Feedwater Rupture Control System trip and isolation of both steam generators. Steam generator 2 level was restored in about 5 minutes by operation of auxiliary feed pump 2, which had been out of service for surveillance testing as required by the DB-1 Technical Specifications. Auxiliary feedwater was supplied to steam generator 1 normally. The improper switchgear fuse was replaced. See Reportable Occurrence NP-33-79-13 dated February 9, 1979. At the time of the occurrence, the Unit was in Mode 1 at 2772 MWT.

APPENDIX S

ARKANSAS NUCLEAR ONE, UNIT 1

ARKANSAS POWER & LIGHT COMPANY

Response to Item 2 of I&E Bulletin 79-05A

Each Licensee for a B&W operating plant was requested to respond to Item 2 of IE Bulletin 79-05A. Item 2 was stated as follows:

> "Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item."

Response to Item 2

We have reviewed similar transients at ANO-1 inclusive of Loss of Offsite Power, Loss of Feedwater, Turbine Trip, Load Rejection, and Reactor Trip. For all transients, ANO-1 performed as expected with no significant deviations with the following exception.

Following a reactor trip from 100% power in December, 1974, (start-up testing) and again following a reactor trip from 100% power in May, 1975, ANO-1 experienced a momentary loss of pressurizer level indication. The loss of indication ranged from approximately 20 to 40 seconds. Following these occurrences the Plant Safety Committee (PSC), the Safety Review Committee (SRC), and B&W thoroughly analyzed the situation.

The results of the analyses indicated that pressurizer level had dropped only approximately 8 inches below 0" indicated. Approximately 96" of actual pressurizer water level remained in the pressurizer.

It was further determined that the level drop was due to RCS shrinkage from cooling.

Following investigation, we determined that RCS Tave following a reactor trip was slightly lower than design. We further determined that by fine tuning the Integrated Control System (ICS) runback of feedwater and setpoints of steam relief and bypass valves we could maintain an approximately 2F higher Tave which would reduce shrinkage such that pressurizer level indication would no longer be lost following a reactor trip.

ICS runback of feedwater and setpoint adjustment of the steam bypass valves were subsequently adjusted in early 1976 and in early 1977 setpoint adjustment of the steam relief valves was subsequently adjusted to increase Tave. As a result, level indication has not been lost on any subsequent transients.

The results of the PSC, SRC, and B&W reviews indicated that the momentary loss of pressurizer level indication was not a safety issue. The loss of indication was not an anomaly of the system, but was due to a lack of fine tuning of the system. The two occurrences compared favorably, that is, pressurizer level responded approximately the same in both instances. Further, should pressurizer level have decreased further, Safety Injection would have been automatically initiated at approximately 1500 psig. 1500 psig in the RCS would have been reached considerably before pressurizer level dropped out of the pressurizer. Therefore, level indication would have been restored by HPI and, as desired, the steam bubble would have remained in the pressurizer.

Further, the NRC recently raised this issue on another B&W unit. In a February 14, 1979, meeting in Lynchburg, Virginia, with the NRC Special Investigative Team, B&W owners and B&W, we presented information on the ANO-1 occurrences and analyses.

We have reviewed our analyses of 1975, and maintain that our conclusions at that time were and are still valid.

APPENDIX T

EXCERPT FROM TMI-2 FSAR

15.1.8 LOSS OF NORMAL FEEDWATER

15.1.8.1 Identification of Causes

A loss of feedwater accident results from either a reduction in or the complete loss of normal feedwater flow to the steam generators. With loss or reduction of feedwater to the steam generators, the capability of the secondary system to remove the heat generated in the reactor coolant system is impaired. Reactor trip, however, occurs before the steam generator heat transfer capability is significantly reduced. Since the emergency feedwater system is also available to remove the decay heat generated following reactor trip, fuel and reactor coolant system boundary system damage will not occur. Loss of feedwater may result from abnormal closure of a feedwater valve, pump failure, or a feedwater line break.

15.1.8.2 Analysis of Effects and Consequences

15.1.8.2.1 Safety Evaluation Criteria

The safety evaluation criteria for this accident are:

a. The core thermal power shall not exceed 112% of rated power.

b. Reactor coolant system pressure shall not exceed code pressure limits.

15.1.8.2.2 Methods of Analysis

A B&W digital computer code[14] was used to determine the characteristics of this accident. Included were a complete kinetics model, pressure model, average fuel rod model, steam demand model with secondary coastdown to decay heat level, coolant transport model, and a simulation of the instrumentation for pressure and flux trip. The initial conditions were normal rated power operation without automatic control. Only the Doppler and moderator coefficients of reactivity were used as feedback. The nominal values used for the main parameters in evaluating this accident are given in Table 15.1.8-1. For trip, the minimum control rod worth that satisfies the criterion for a shutdown margin of 1% $\Delta k/k$ at the hot standby condition is used through the analysis.

15.1.8.2.3 Results of Analysis

For a loss of feedwater accident due to a feedwater valve failure, feedwater pump failure, or feedwater line break upstream of the first feedwater line upstream check valve, the complete loss of normal feedwater has been analyzed as this is the most conservative case. The sequence of events (see Table 15.1.8-2) and the evaluation of consequences are as follows:

a. Termination of all feedwater results in a reduction in secondary system heat removal capability.

b. Increased reactor coolant system pressure results in a reactor trip which causes the turbine to trip.

c. The turbine trip closes the turbine stop valves.

d. The turbine driven and the electric driven emergency feedwater pumps are started on loss of main feedwater pumps, loss of all 4 RCP's or low feedline/steamline dp,

e. Following closure of the turbine stop valves, secondary system steam is relieved through the turbine bypass and steam safety valves.

f. Steam will be vented to the atmosphere until the turbine bypass valves can handle all excess steam generated.

g. Eventually, thermal equilibrium is reestablished; i.e., the heat removal rate (steam flow through the turbine bypass valve) is equal to the heat input (core decay heat).

h. Decay heat removal and cooldown of the reactor coolant system is then provided by steam relief to the condenser through the turbine bypass valves with the feedwater being supplied by the emergency feedwater system.

i. Figure 15.1.8-1 shows neutron power, thermal power, reactor coolant system pressure, and core average moderator temperature for the transient.

Since the core thermal power does not exceed 112% and the reactor coolant system pressure does not exceed design limits, the safety evaluation criteria are met.

15.1.8.2.4 Environmental Consequences

The loss of normal feedwater due to a feedwater line break between the first feedwater line upstream check valve and the steam generator results in doses no worse than those reported for the steam line break accident, Table 15.1.15-4. The loss of feedwater due to equipment malfunction or feedwater line break upstream of the first feedwater line upstream check valves results in doses no worse than those reported for the loss of AC power accident, Table 15.1.9-1. For either situation the resultant doses are well within the guidelines of 10 CFR 100.

15.1.8.2.5 Reactor Building Pressure

For the reactor building pressure evaluation, the worst conditions following a feedwater line break occur as a result of a break in the main feedwater header to a steam generator. This break location results in the fastest steam generator blowdown and thus the fastest high enthalpy mass release to the reactor building.

The flow from the feedwater system side of the break was computed using the RELAP 3 computer code (USAEC Report IN 1321). All main feedwater flow was assumed to bypass the steam generators and exit through the break to the reactor building.

A digital computer program[18] was used to determine the affected steam generator blowdown characteristics. This multinode model permitted the detailed programming of the steam generators and their interconnecting piping and valves within the main steam system. The following assumptions were made:

a. The main steam isolation valves and turbine stop valves were left open.

b. Flow to the turbine is cut off as soon as the secondary pressure drops below the turbine steady-state value (this forces the mass/energy that would have gone to the turbine to go out the break).

c. Provisions were made to allow the inventory in the unaffected steam generator feedwater line to boil off and pass through the steam generators and out the break (this effect begins when the pressure drops below the saturation pressure of the feedwater).

After the blowdown, the building's cooling capability is adequate to handle the residual heat removal from the RC system by auxiliary feedwater flow to the affected steam generator.

The mass and energy released to the reactor building are given in Table 15.1.8-3. Reactor building pressure calculations were made using the CONTEMPT code described in 6.2.1.3.2.

Using these methods, the peak containment pressure is 35 psig, assuming that passive heat sinks and two emergency fan coolers are available. Thus, the results of the containment pressure analysis for the feedwater line break accident are within those predicted by the DBA (see 6.2.1.3.2) and the reactor building design pressure of 60 psig.

TABLE 15.1.8-1

LOSS OF NORMAL FEEDWATER ACCIDENT PARAMETERS

Doppler coefficient at rated power (BOL), 10^{-5} $\Delta k/k/F$	-1.22
Moderator coefficient at rated power (BOL), 10^{-4} $\Delta k/k/F$	+0.9
Trip parameters	
Delay for high-pressure trip, s	0.5
Delay for high-flux trip, s	0.3
Control rod travel time to 2/3 insertion, s	1.4

TABLE 15.1.8-2

SUMMARY OF LOSS OF NORMAL FEEDWATER ANALYSIS

Reactor trip, s	13.4
Emergency feedwater initiation, s	40
Maximum reactor coolant system pressure, psia	2515
Maximum core thermal power, %	100

Table 15.1.8-3. Feedwater Line Break Transient Mass and Energy Realease Rates

Time after rupture during SG blowdown, s	Mass release rate, lb/s	Energy release rate, Btu/s
0	0	0
0.1	1.01+4	5.67+6
0.2	1.04+4	5.71+6
0.3	1.04+4	5.69+6
0.4	1.03+4	5.65+6
0.5	1.01+4	5.60+6
0.6	9.88+3	5.54+6
0.7	9.65+3	5.48+6
0.8	9.69+3	5.48+6
0.9	9.53+3	5.43+6
1.0	9.10+3	5.32+6
1.2	9.37+3	5.40+6
1.4	9.17+3	5.35+6
1.6	9.10+3	5.34+6
1.8	9.22+3	5.38+6
2.0	8.83+3	5.29+6
2.2	9.20+3	5.39+6
2.4	9.21+3	5.39+6
2.6	8.98+3	5.32+6
2.8	9.03+3	5.33+6
3.0	9.19+3	5.38+6
3.2	8.80+3	5.27+6
3.4	8.96+3	5.31+6
3.6	8.80+3	5.27+6
3.8	8.86+3	5.30+6
4.0	8.65+3	5.22+6
4.6	8.34+3	5.15+6
5.0	8.03+3	5.04+6
5.2	7.73+3	4.94+6
5.4	7.28+3	4.76+6
5.6	6.67+3	4.56+6
5.8	6.05+3	4.32+6
6.0	5.56+3	4.14+6
6.2	5.13+3	4.0 +6
6.4	4.81+3	3.9 +6
6.6	4.60+3	3.84+6
6.8	4.40+3	3.77+6
7.0	4.19+3	3.69+6
7.2	3.96+3	3.60+6
7.4	3.74+3	3.52+6
7.6	3.57+3	3.45+6
7.8	3.4 +3	3.39+6
8.0	3.26+3	3.33+6
8.2	3.12+3	3.26+6
8.4	3.00+3	3.21+6
8.6	2.89+3	3.18+6
8.8	2.81+3	3.14+6
9.0	2.74+3	3.12+6
9.2	2.69+3	3.09+6
9.4	2.63+3	3.07+6
9.6	2.59+3	3.05+6
9.8	2.58+3	3.04+6
10.0	2.54+3	3.06+6
11.0	2.51+3	3.14+6
12.0	2.51+3	3.15+6
13.0	2.49+3	3.14+6
14.0	2.47+3	3.11+6
15.0	2.43+3	3.07+6
16.0	2.38+3	3.01+6
18.0	2.29+3	2.90+6
20.0	2.18+3	2.77+6
22.0	2.07+3	2.63+6
24.0	1.94+3	2.46+6
26.0	1.83+3	2.33+6
28.0	1.69+3	2.15+6
30.0	1.60+3	2.03+6
32.0	1.49+3	1.90+6[a]
52.0	1.19+3[a]	1.42+6[a]
74.1	1.19+3[a]	1.42+6[a]
TOTALS	163.7+3	167.2+6

[a] Extrapolated.

TABLE 15.1.8-3

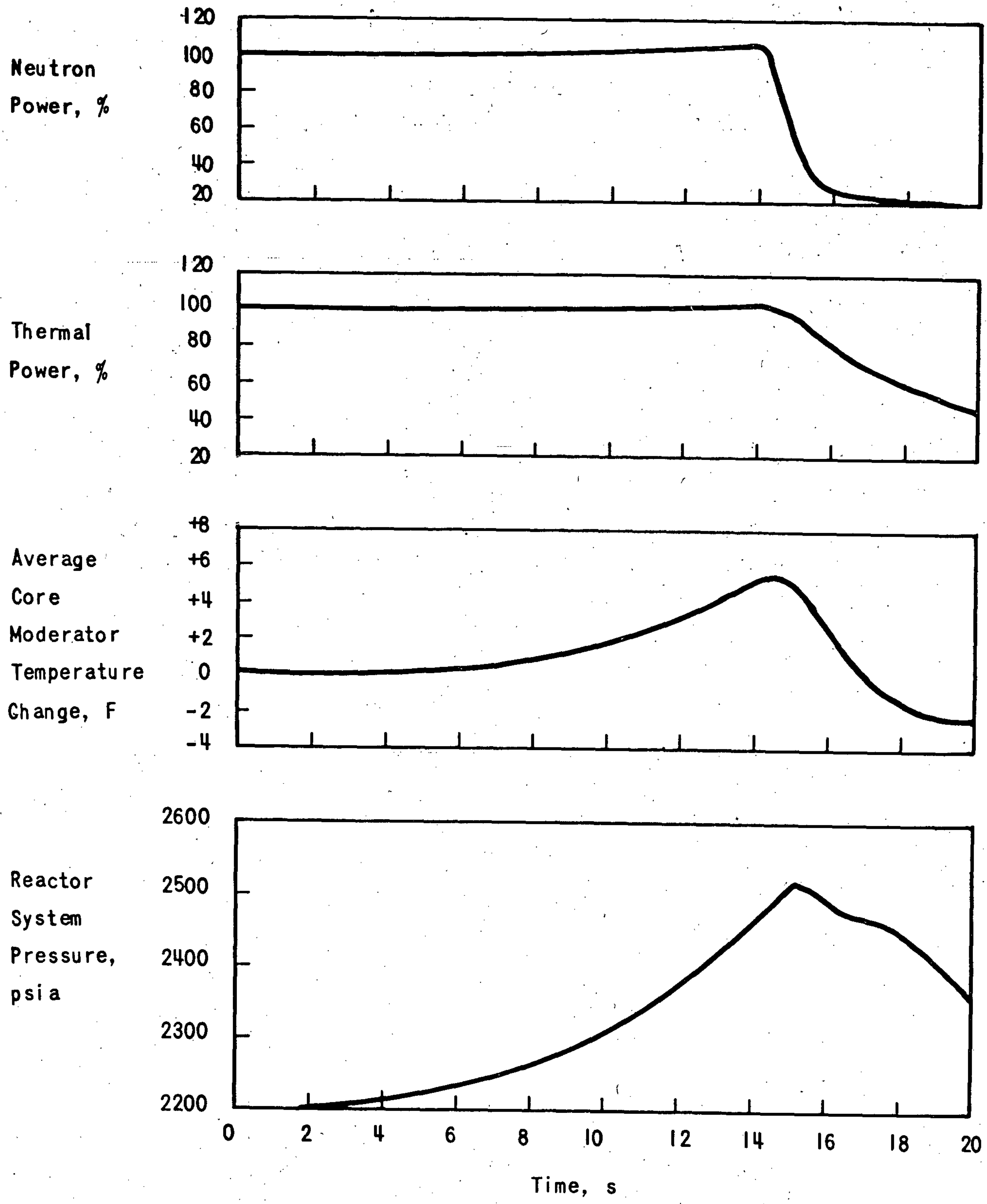
FEEDWATER LINE BREAK TRANSIENT MASS AND ENERGY RELEASE RATES (CONT'D)

Time after rupture, s	Mass release rate, lb/s	Energy release rate, Btu/s
Feedwater Piping Release		
0.0 - 0.1	5.1700 (3)	2.0739 (6)
0.1 - 0.2	5.7439 (3)	2.3007 (6)
0.2 - 0.3	5.7097 (3)	2.2862 (6)
0.3 - 0.4	5.6962 (3)	2.2801 (6)
0.4 - 0.5	5.6935 (3)	2.2782 (6)
0.5 - 0.6	5.6933 (3)	2.2774 (6)
0.6 - 0.7	5.6835 (3)	2.2727 (6)
0.7 - 0.8	5.6714 (3)	2.2670 (6)
0.8 - 0.9	5.6592 (3)	2.2614 (6)
0.9 - 1.0	5.6472 (3)	2.2558 (6)
1.0 - 1.1	5.6352 (3)	2.2503 (6)
1.1 - 1.2	5.6235 (3)	2.2448 (6)
1.2 - 1.3	5.6125 (3)	2.2396 (6)
1.3 - 1.4	5.5996 (3)	2.2337 (6)
1.4 - 1.5	5.5946 (3)	2.2309 (6)
1.5 - 1.6	5.5862 (3)	2.2267 (6)
1.6 - 1.7	5.5776 (3)	2.2225 (6)
1.7 - 1.8	5.5692 (3)	2.2184 (6)
1.8 - 1.9	5.5606 (3)	2.2141 (6)
1.9 - 2.0	5.5521 (3)	2.2100 (6)
2.0 - 2.5	5.5264 (3)	2.1974 (6)
2.5 - 3.0	5.4826 (3)	2.1759 (6)
3.0 - 3.5	5.4372 (3)	2.1538 (6)
3.5 - 4.0	5.3903 (3)	2.1311 (6)
4.0 - 4.5	5.3410 (3)	2.1070 (6)
4.5 - 5.0	5.2913 (3)	2.0835 (6)
5.0 - 5.5	5.2373 (3)	2.0578 (6)
5.5 - 6.0	5.1833 (3)	2.0323 (6)
6.0 - 7.0	5.0931 (3)	1.9901 (6)
7.0 - 8.0	4.9645 (3)	1.9265 (6)
8.0 - 9.0	4.8190 (3)	1.8648 (6)
9.0 - 10.0	4.6545 (3)	1.7916 (6)
10.0 - 12.0	4.3704 (3)	1.6675 (6)
12.0 - 14.0	3.9281 (3)	1.4773 (6)
14.0 - 16.0	3.4667 (3)	1.2868 (6)
16.0 - 18.0	3.1987 (3)	1.1680 (6)
18.0 - 20.0	2.9774 (3)	1.0680 (6)
20.0 - 22.0	2.8682 (3)	1.0087 (6)
22.0 - 24.0	2.6894 (3)	0.9255 (6)
24.0 - 27.0	2.2193 (3)	0.7418 (6)
27.0 - 30.0	1.8091 (3)	0.58509 (6)
31.0 - 40.0	1.4706 (3)	0.45196 (6)

TABLE 15.1.8-3

FEEDWATER LINE BREAK TRANSIENT MASS AND ENERGY RELEASE RATES (CONT'D)

Time after rupture, s	Mass release rate, lb/s	Energy release rate, Btu/s
Feedwater Piping Release		
41.0 - 50.0	1.3460 (3)	0.39547 (6)
51.0 - 60.0	1.2969 (3)	0.36483 (6)
61.0 - 70.0	1.2765 (3)	0.34301 (6)
71.0 - 80.0	1.2478 (3)	0.31969 (6)
81.0 - 90.0	1.3528 (3)	0.33303 (6)
91.0 - 100.0	1.4351 (3)	0.33252 (6)
101.0 - 110.0	1.3108 (3)	0.28811 (6)
111.0 - 120.0	1.1257 (3)	0.23583 (6)
121.0 - 130.0	0.9215 (3)	0.185215 (6)
131.0 - 140.0	1.0393 (3)	0.20153 (6)
141.0 - 150.0	0.8766 (3)	0.16458 (6)
Total releases	2.1693 (5)	8.29007 (7)



LOSS OF NORMAL FEEDWATER FROM RATED POWER
THREE MILE ISLAND NUCLEAR STATION UNIT 2

FIGURE 15.1.8-1

APPENDIX U

LETTER FROM BABCOCK & WILCOX

APRIL 30, 1979

Babcock & Wilcox

Power Generation Group

P.O. Box 1260, Lynchburg, Va. 24505
Telephone: (804) 384-5111

April 30, 1979

Dr. R. J. Mattson
Director, Division of Systems Safety
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Babcock & Wilcox Company's Commitments

Dear Dr. Mattson:

Attached is a summary of the Babcock & Wilcox Company's commitments that have resulted from various meetings and correspondence over the past few weeks; this is a complete list of our commitments as I see them. I have indicated the date by which B&W intends to complete each commitment; however, no allowance has been made for prior review of these submittals by the licensees. Should they require prior review, submittals to the Nuclear Regulatory Commission could be delayed slightly. It should be noted that some of the dates have been extended beyond those originally discussed with the staff because of the very significant work effort required in connection with the small break guidelines and procedures.

Also attached is a copy of the meeting minutes from the April 26, 1979 meeting with the NRC staff.

If you have any questions, please call me (Ext. 2817).

Very truly yours,

James H. Taylor
Manager, Licensing

JHT:nw

Attachments

bcc: E.A. Womack
R.E. Wascher
D.W. LaBelle
B.M. Dunn
D.H. Roy

B&W ANALYTICAL COMMITMENTS
RESPONSIVE TO NRC STAFF SAFETY CONCERNS
IDENTIFIED IN "NRR STATUS REPORT
ON FEEDWATER TRANSIENTS IN
B&W PLANTS" OF APRIL 25, 1979

I. Commitments from B&W/NRC Meeting on April 17, 1979 (Reference 1)

A. Perform calculations, worst-case break without AFW for 30 minutes.

Due: April 21, 1979
Submitted: April 21, 1979
Outstanding: Detailed results discussed with staff on April 26, 1979. Detailed report to be submitted May 21, 1979. (See Reference 2, Item 5.)

B. Document natural circulation tests conducted at Davis Besse and Oconee.

Due: May 7, 1979

C. Document all occurrences of natural circulation which happened inadvertently; include a description of unexpected behavior.

Due: May 7, 1979

D. Document natural circulation analytical methods.

Due: May 16, 1979

E. Summarize and document sensitivity in key parameters (not to be started until release of R. Tedesco report)

Due: Eight weeks following receipt of Tedesco report.

F. Deleted

G. Define and document thermal shock criteria for operation at low temperature with HPI pumps running and no natural circulation.

Due: Two weeks following receipt of Tedescho report.

H. Assessment of the safety concerns raised in the report of Dr. Michelson.

Due: May 7, 1979

Outstanding: Basis for concluding that Michelson concerns do not invalidate 10CFR50.46 analyses for small breaks were discussed with staff on April 17, 1979 (See Reference 1, page 7) and on April 25, 1979.

II. <u>Commitments in Taylor to Mattson Letter of April 25, 1979</u> (Reference 2)

A. CRAFT Analyses

1. Item 1 (Reference 2)

Due: May 4, 1979

Status: Some detailed results submitted herewith Figures 28-30.
Remainder to be submitted May 21, 1979.

2. Item 2

Due: May 4, 1979

Status: Details discussed with and some results submitted to NRC staff on April 16, 1979. Figures 17-21 submitted herewith.
Remainder to be submitted May 21, 1979.

3. Item 3

Due: May 4, 1979
To be combined with Item 4.

4. Item 4

Due: May 4, 1979

Some detailed results discussed with staff on April 26, 1979. Figures 6-11 submitted herewith. Remainder to be submitted May 21, 1979.

5. Item 5

Due: May 4, 1979
Submitted: See Item I.A. above

6. Item 6

Due: May 4, 1979
To be submitted May 21, 1979.

7. Item 7

Due: May 4, 1979

Detail results discussed with staff on April 26, 1979. Figures 22-27 submitted herewith. Remainder to be submitted May 21, 1979.

8. Item 8

Due: May 4, 1979
To be submitted May 21, 1979.

B. CADDS Analyses

1. Item 1 (Reference 2)

Due: May 4, 1979

Detail results discussed with staff on April 26, 1979. Figures 1-3 submitted herewith. Remainder to be submitted May 9, 1979.

2. Item 2.a.

Due: May 4, 1979

Detail results discussed with staff on April 26, 1979. Figures 4-5 submitted herewith. Remainder to be submitted May 9, 1979.

3. Item 2.b.

Due: May 4, 1979

To be submitted May 9, 1979.

4. Item 2.c.

Due: May 4, 1979
To be submitted May 9, 1979.

5. Item 2.d.

Due: May 4, 1979
To be submitted May 9, 1979.

III. Commitments in Roy to Mattson Letter of April 26, 1979 (Reference 3)

A. Details of results of the analyses described in Reference 2.

Due:
Submitted: See II Above
Outstanding:

B. Details of B&W's evaluation of the Michelson report

Due:
Submitted:
Outstanding: See I.H. Above

C. System response to total loss of steam generator heat sink

To be submitted May 25, 1979.

D. Sensitivity study of system response to auxiliary feedwater flow rate

To be submitted May 25, 1979.

E. Effect of anticipatory trip on loss of main feedwater

See II.B.2 above

IV. Staff Requests for Additional Analyses at B&W/NRC Meeting of April 26, 1979 (Reference 4)

A. Benchmark analysis of sequential auxiliary feedwater flow to OTSG's for LOMFW.

To be submitted May 21, 1979.

B. System response to PORV and code safety valve actuation.

To be submitted June 1, 1979.

C. Ideas on benchmarking of natural circulation modes of cooling CRAFT II.

To be submitted July 2, 1979.

D. Evaluation of Michelson report concerns and outline of operating criteria for small breaks.

Due: See I.H. above and V.A. below.

E. Worst case small break with no auxiliary feedwater flow and single ECCS failure

To be submitted July 2, 1979.

V. Analysis Commitments in MacMillan to Denton Letter of April 26, 1979 (Reference 5)--Reliability Analysis of ICS

Due:
Submitted:
Outstanding: Scope and schedule were submitted on April 28, 1979, by letter J.H. Taylor to H.R. Denton.

VI. Analysis Commitments in W. S. Lee to H. R. Denton Letter of April 26, 1979 (Reference 6)

A. Operating instruction for management of small breaks

Due: May 15, 1979 (procedures in control room)
Submitted:
Outstanding: B&W to submit guidelines for developing procedure, approved by NRC, to Duke Power Co. on or before May 12, 1979.

B. ICS FMEA

Due: See V above

B&W ENGINEERING (OTHER THAN
ANALYTICAL) COMMITMENTS RESPONSIVE TO
NRC STAFF SAFETY CONCERNS IDENTIFIED
IN "NRR STATUS REPORT ON FEEDWATER
TRANSIENTS IN B&W PLANTS" OF APRIL 25, 1979

I. Commitments in MacMillan to Denton Letter of April 26, 1979 (Reference 1)--Develop Means for Decoupling Auxiliary Feedwater Control from ICS

Submitted: April 28, 1979

II. Commitments in MacMillan to Denton Letter of April 26, 1979 (Reference 2)

A. More positive indication of the position of the pilot-operated relief valve

Due: May 28, 1979

Completion on this date consists of transmittal of technical hardware description to operating plant owners.

B. Saturated condition indicator for reactor coolant

Due: May 30, 1979

Completion on this date consists of transmittal of technical hardware description to operating plant owners.

Babcock & Wilcox

1725 K Street, N.W., Washington, D.C. 20036
Telephone: (202) 296-0390

April 26, 1979

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20555

Dear Mr. Denton:

Subject: Integrated Control System

This letter documents the commitment of Babcock & Wilcox to undertake a reliability analysis of the Integrated Control System (ICS) which will include a failure mode and effects analysis. This analysis will identify sources of transients, if any, initiated by the ICS and develop recommended design improvements which may be necessary to reduce the frequency of these transients.

In addition, means will be developed for decoupling of the auxiliary feedwater control of steam generator water level from the ICS. This modification will provide control of feedwater under emergency conditions independent of the ICS.

The scope of the reliability analysis and schedule for both the analysis and development of independent feedwater control will be provided within 48 hours.

Sincerely,

John H. MacMillan
Vice President
Nuclear Power Generation
Division

cc: W. S. Lee
Duke Power Company
John Mattimoe
Sacramento Municipal Utility District
William Cavanaugh
Arkansas Power & Light
William Griffin
Florida Power Corporation
John Herbein
Metropolitan Edison Company
Lowell Roe
Toledo Edison Company

Babcock & Wilcox
1725 K Street, N.W., Washington, D.C. 20006
Telephone: (202) 296-0390

April 26, 1979

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20555

Dear Mr. Denton:

Subject: Near-Term Design Improvements

In the April 16, 1979 meeting with the ACRS, I identified several near-term actions which Babcock & Wilcox was committed to undertake. Two near-term design improvements which evolved from our evaluation of the TMI-2 accident are a more positive indication of the position of the power operated relief valve and a saturated temperature condition indicator for the reactor coolant system. These instruments will provide additional information to the operators which improve their ability to identify an open relief valve and maintain subcooled temperatures in the reactor coolant system to provide adequate core cooling. These improvements are currently in the design and development phases. The schedule for completion is consistent with the six week commitment indicated at the ACRS meeting.

Sincerely,

John H. MacMillan
Vice President
Nuclear Power Generation
Division

cc: W. S. Lee
Duke Power Company
John Mattimoe
Sacramento Municipal Utility District
William Cavanaugh
Arkansas Power & Light
William Griffin
Florida Power Corporation
John Herbein
Metropolitan Edison Company
Lowell Roe
Toledo Edison Company

MINUTES OF THE MEETING
OF
BABCOCK & WILCOX AND THE NUCLEAR REGULATORY COMMISSION
DISCUSSION ON SMALL LOCA ANALYSIS
April 26, 1979

Short Term Transient Analysis

CADD-S

See CADDS studies list (P.4), April 25, 1979 B&W letter[1]

General Model Characteristics

- Used for analyses up until time system becomes 2-phase
- Suitable for sensitivity analyses for delays of auxiliary feedwater, variation in feedwater flow, variations in reactor trip mode or setpoint.
- System actions which will be investigated (out to about 8-10 minutes) are:
  - Reactor trip time
  - Peak pressures achieved in initial pressurization
  - Time and valve of repressurization
  - Time to fill pressurizer
- Code Limitations
  - Not valid for 2-phase, saturated conditions (use CRAFT)
  - HPI not precisely modeled (use CRAFT)
  - One loop

TMI-2 Benchmark

(Case #1 of Ref. A CADDS study)

Curves of pressure, pressurizer level comparison to TMI-2 transient of March 28, 1979, are in Attachment 1, Figures 1-3.

Sensitivity of Repressurization to Auxiliary Feedwater Initiation Time

(Case #2, CADDS study)

Curves of pressure and pressurizer level for three representative cases are in Attachment 2, Figures 4-5.

Staff Request 1: Show benchmark to plant data (e.g., Davis Besse or equivalent) for case where generators fill in sequence.

Staff Request 2: Examine parametric behavior of PORV's and Safety valves on pressurizer.

- What is operating experience with safety valves opening and closing?
- Why not consider failure of the safety valve as a single failure?
- What are the consequences and expected behavior of a stuck open pressurizer safety valve?
- Consider steam and 2-phase flow discharge.
- Define basis of and treatment justification for flow model through the valves. Include quench tank back pressure effect assessment.

Long Term Transient Analysis

CRAFT-2

See CRAFT analyses, April 25, 1979, B&W letter[1]

Model Used

- Noding as described in Figure 12
- Model handles three modes of natural circulation
  - Solid water
  - 2-phase mass movement
  - Boiling/recondensation
- Natural circulation model of B&W is believed to account correctly for these effects, and is similar to Commission audit models. Data for benchmark to actual system conditions is available only for solid water mode.

Staff Request #3: Further discussions, with the aim of developing benchmarks, are needed.

Michelson Report

B&W considers interrupted natural circulation as an acceptable cooling mode.

Staff Request #4: Provide a description of this cooling mode and outline of emergency operating criteria for the operator to handle it.

- TMI-2 Benchmark

(Case #4 of Ref. 1)

See attachment, Figures 6-11.

Conclusion--Existing codes are capable of handling phenomena seen in TMI-2 case and similar transients.

Loss of Feedwater in Conjunction with 0.01 sq. ft. break

(Case #5 of Ref.1)

- Break size selected to be the largest which would not automatically initiate ECCS high pressure injection in the initial depressurization transient.
- Shows that core damage will not occur in the first 20 minutes of operation in the following mode

  - No auxiliary feedwater
  - No ECCS injection
  - 0.01 $ft.^2$ break

  Action within 20 minutes to establish either auxiliary feedwater* or HPI will avoid core damage for all plants except Davis Besse. At Davis Besse, feedwater would have to be restored, but time available to accomplish this without core uncovery will be somewhat longer due to loop configuration. (*Initiation of AFW will result in ECCS HPI initiation automatically.)
- For breaks larger than 0.01 $ft.^2$, for which ECCS will automatically initiate, there is no need for auxiliary feedwater so long as ECCS function is unimpaired. See attachment, Figures 12-16.

Staff Request #5: Analyze worst case small break assuming a single failure in the ECCS and no AFW. (B&W noted that this would be a very low probability event.)

Presented Loss of Feedwater with Stuck Open PORV

Case with RCS pumps running with AFW (Case #2 of Ref. 1)

- AFW on in 40 seconds.
- PORV stuck open on initial pressure transient.

Date in attachment, Figures 17-21.
Results: No core damage

Presented Stuck Open PORV as the Initiating Event

(Case #7 of Ref. 1)

See attachment, Figures 22-27.

Results: No core damage

Not Presented:

Case #1 of Ref. 1, see CRAFT analyses[1]

See attachment, Figures 28-30.

REFERENCE:

1. B&W letter to Dr. Roger J. Mattson, Director, Division of Systems Safety, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission; from James H. Taylor, Manager, Licensing at B&W; April 25, 1979.

CADDS Simulation Of

3/28/79 TMI-2 Transient

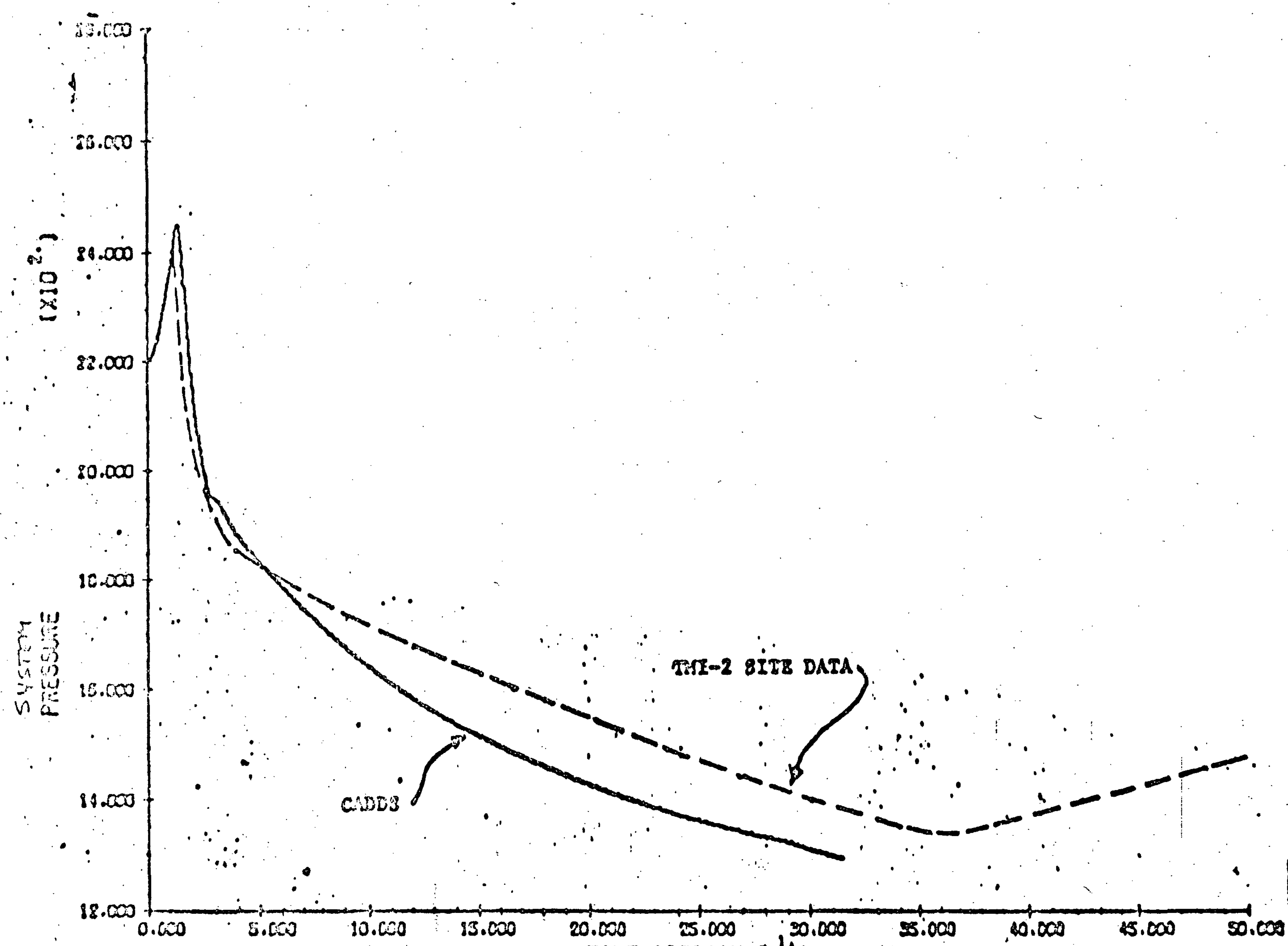
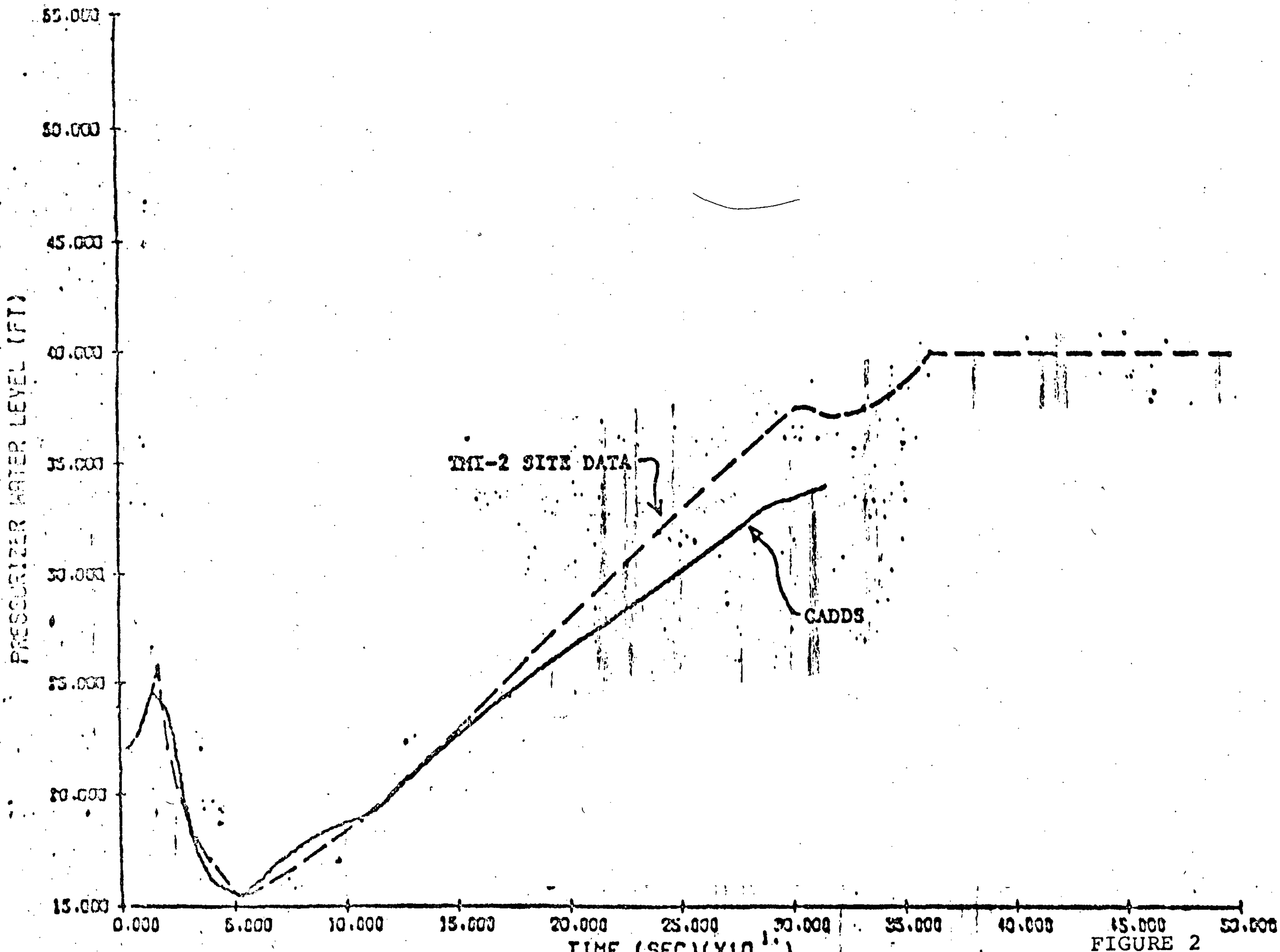
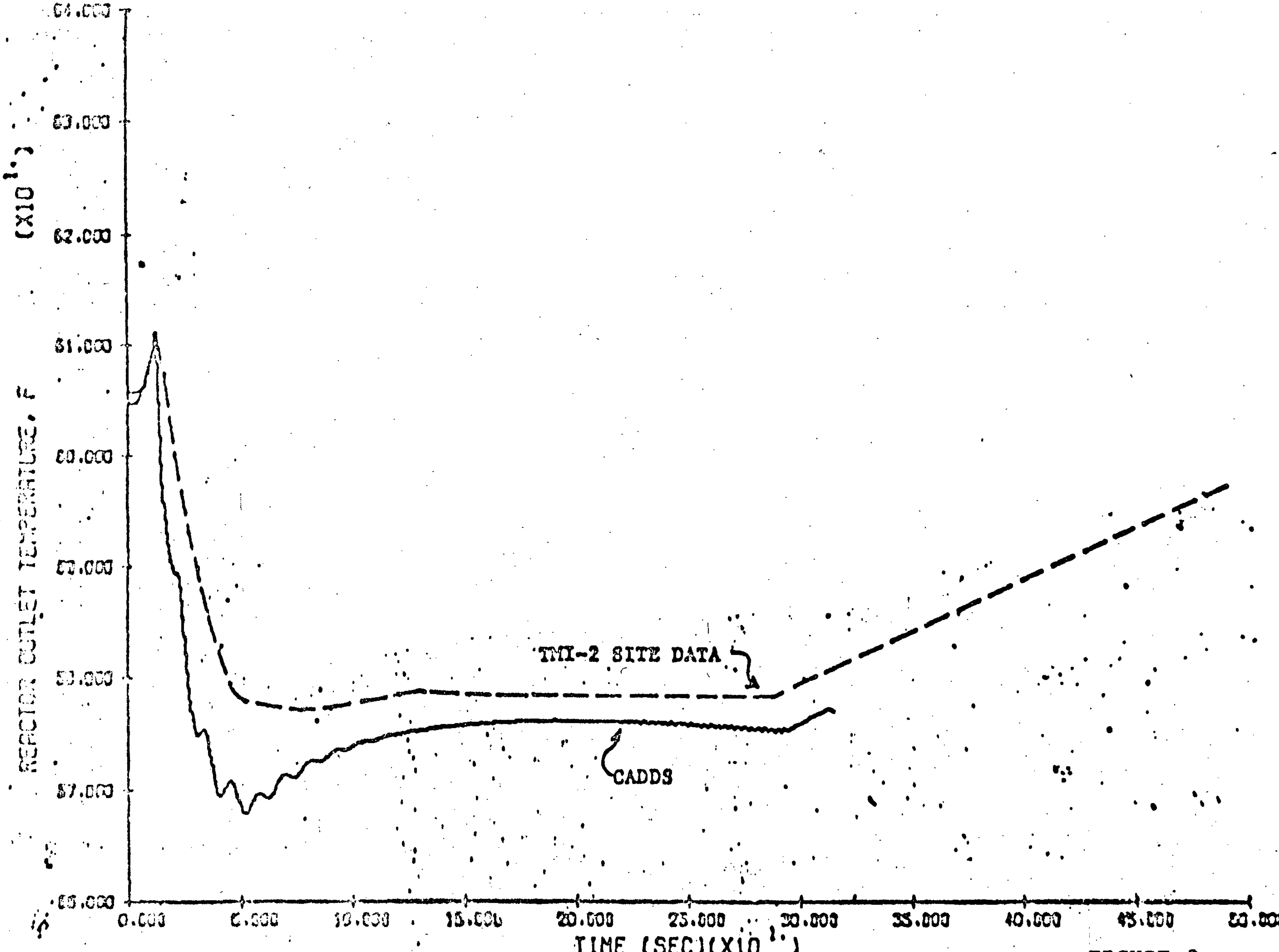


FIGURE 1



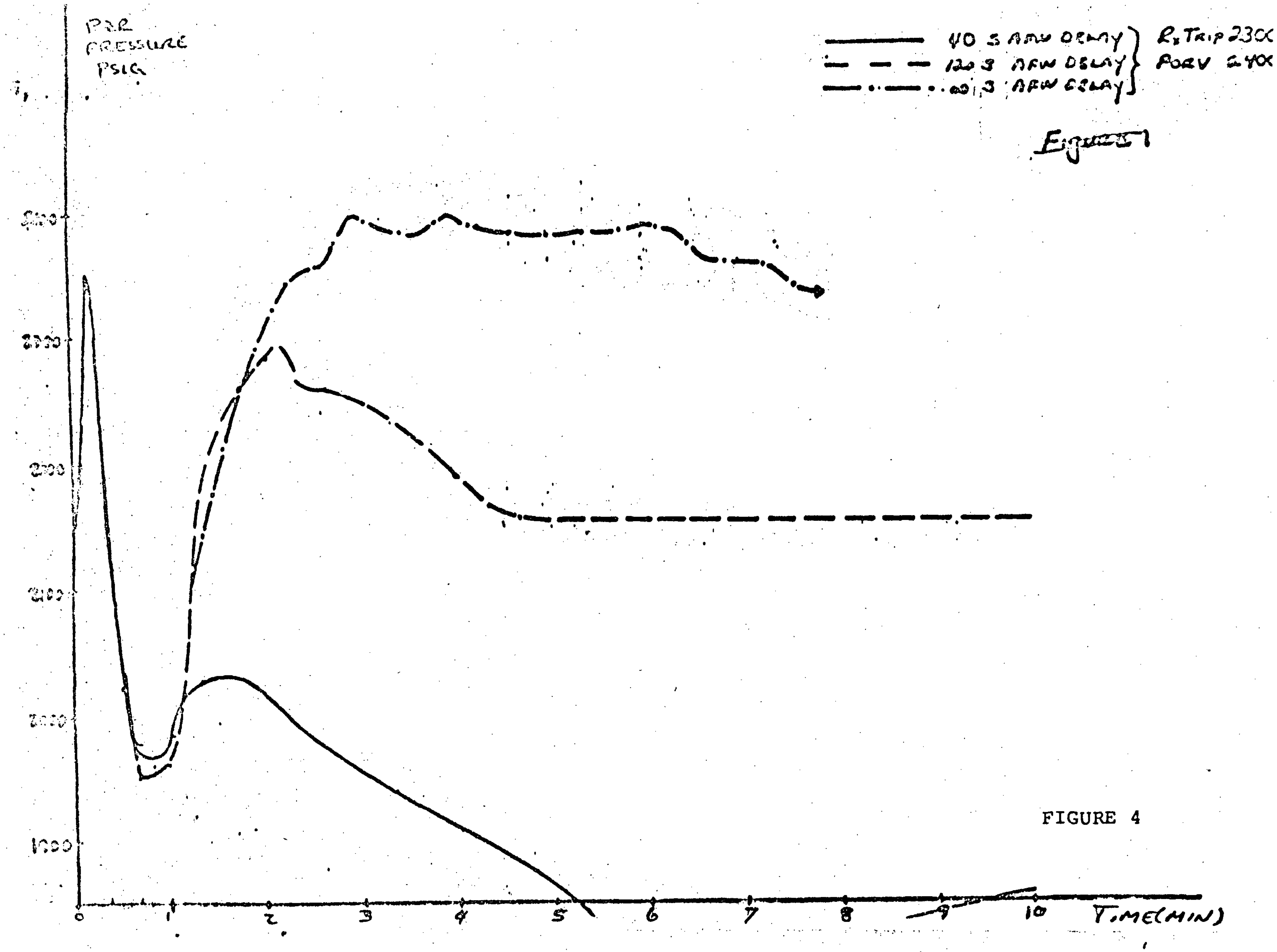
PRESSURIZER WATER LEVEL (FT)
TMI-2 SITE DATA
CADDS
TIME (SEC)(X10

FIGURE 2



TMI-2 LOFW EVENT

FIGURE 3



PZR PRESSURE PSIG
40 S AFW DELAY
120 S AFW DELAY
RxTrip 2300
PORV 2400
Figure 1
2300
2200
2100
2000
1900
1800
1000
0
1
2
3
4
5
6
7
8
9
10
TIME(MIN)

FIGURE 4

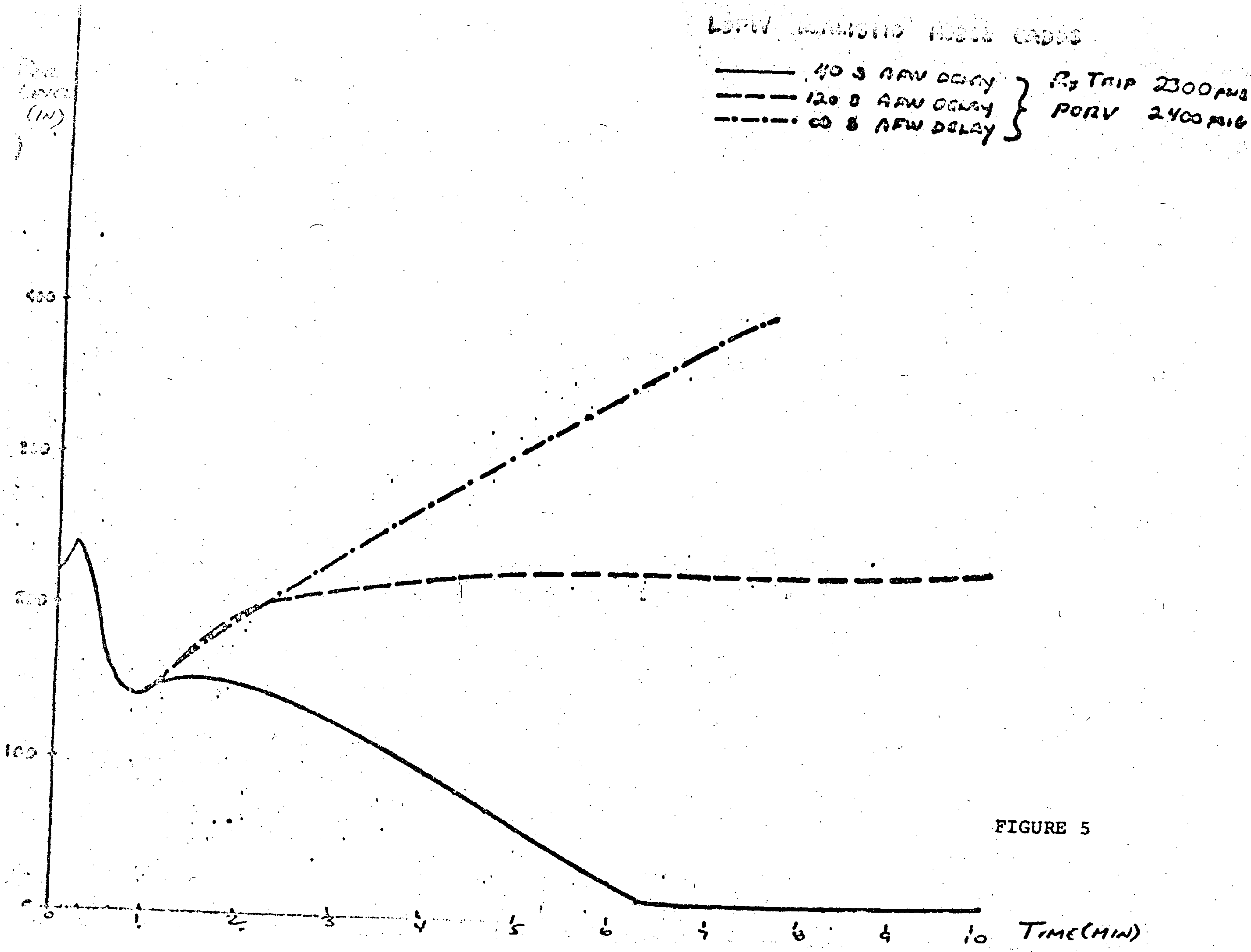

40 S AFW DELAY
120 S AFW DELAY
∞ S AFW DELAY
Rx TRIP 2300 PSIG
PORV 2400 PSIG
100
0
1
2
3
4
5
6
7
8
9
10
TIME (MIN)

FIGURE 5

ATTACHMENT 2

Reference: Letter from J.H. Taylor to R.J. Mattson, April 25, 1979.

Case 4 Results

CRAFT2 SIMULATION OF 3/28/79 TMI-2 TRANSIENT

CRAFT2 COMPUTER MODEL

(FIRST 10 MINUTES)

1. MAIN FEEDWATER COASTDOWN BEGINS AT TIME ZERO.

2. EMOV (RELIEF VALVE IN PRESSURIZER) OPENS AT 8 SECONDS.

3. REACTOR TRIP AT 10 SECONDS

4. MOODY LEAK DISCHARGE CORRELATION USED

$$C_d = 1.0 \text{ IF SUBCOOLED}$$

$$= 0.8 \text{ IF TWO PHASE OR STEAM}$$

5. STEAM GENERATOR HEAT TRANSFER RAMPED TO ZERO IN ONE MINUTE. FULL HEAT TRANSFER IS REINSTATED WHEN AUXILIARY FEEDWATER (50% CAPACITY) START AT 8 MINUTES

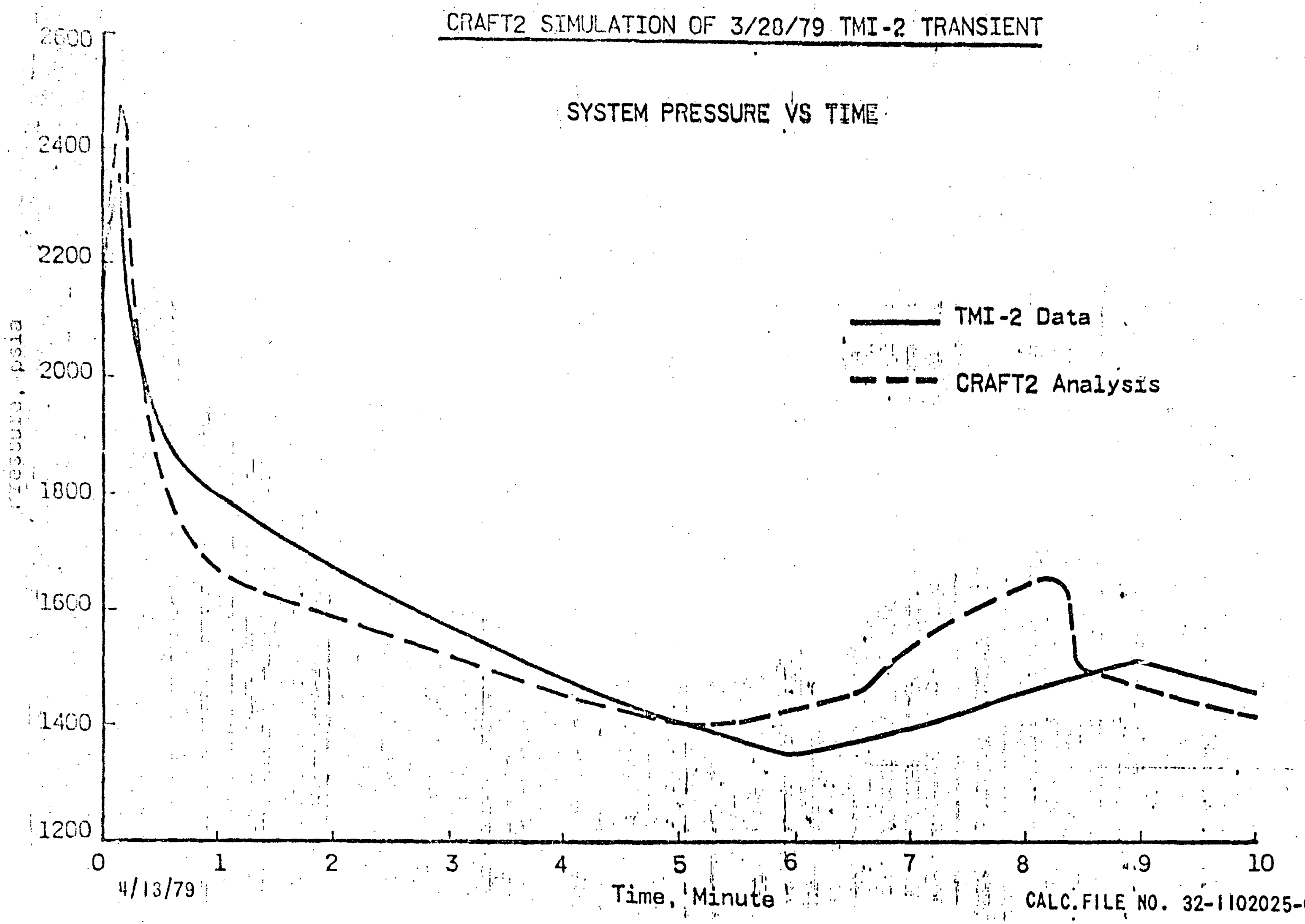
6. a. TWO HPI INJECTION AFTER 2 MINUTES (EACH 500 GPM CAPACITY)

   b. ONLY ONE HPI INJECTION AFTER 4.75 MINUTES (400 GPM CAPACITY)

4/13/79

CALC. FILE NO. 32-1102025-00

FIGURE 6



CALC. FILE NO. 32-1102025-00

FIGURE 7

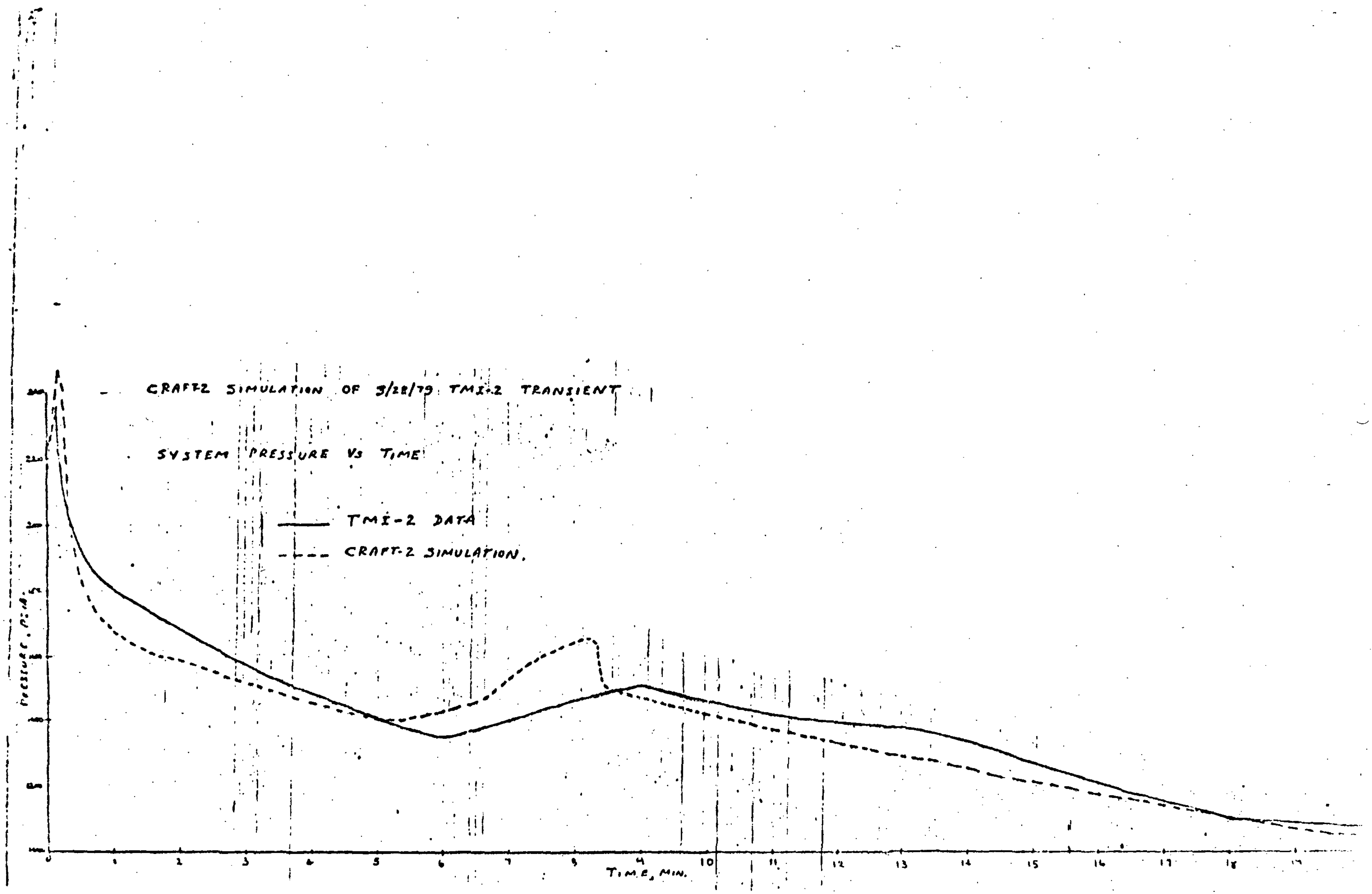
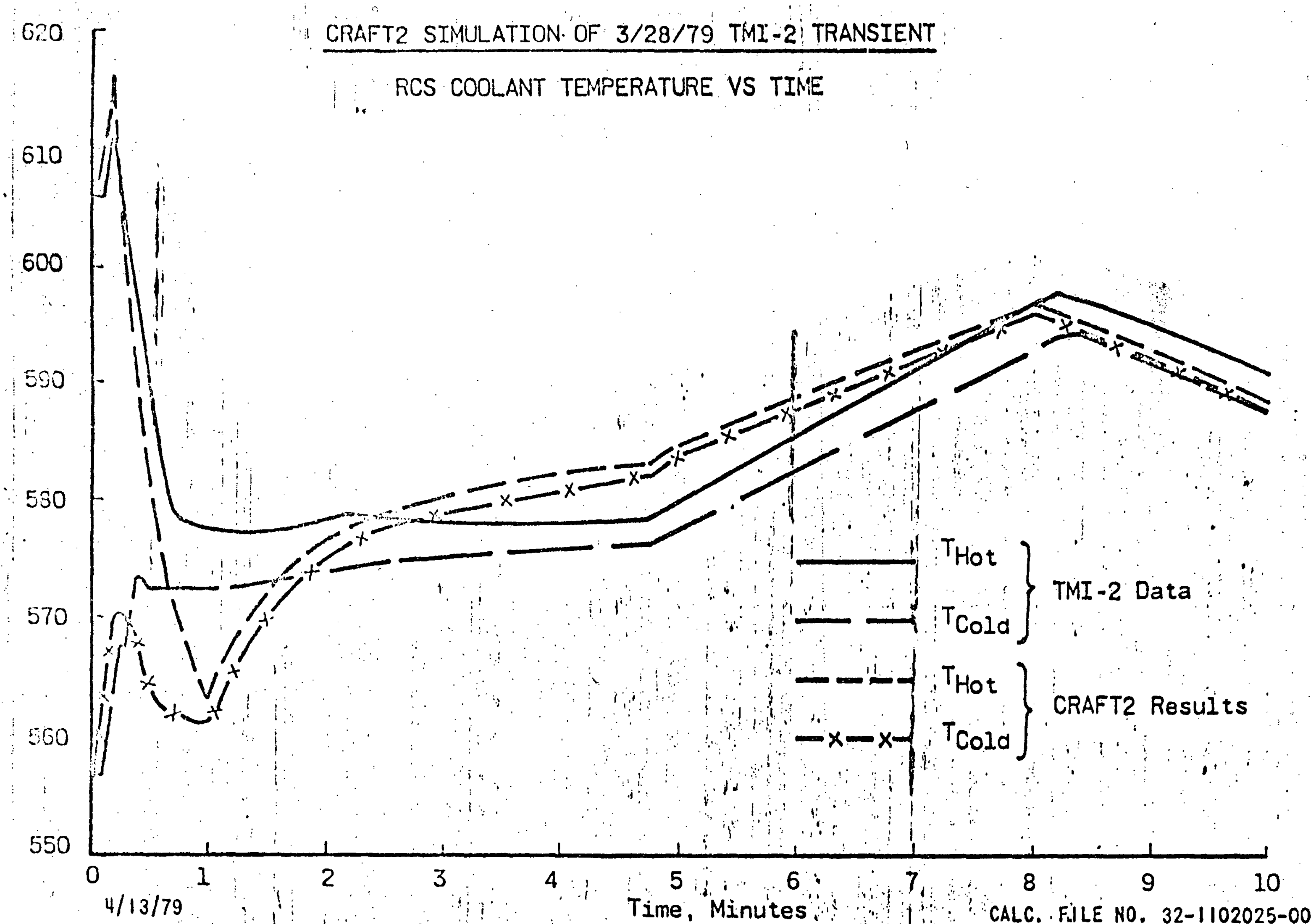

CRAFT2 SIMULATION OF 3/28/79 TMI-2 TRANSIENT
SYSTEM PRESSURE VS TIME
TMI-2 DATA
CRAFT-2 SIMULATION
PRESSURE, PSIA
TIME, MIN.

FIGURE 8



4/13/79

CALC. FILE NO. 32-1102025-00

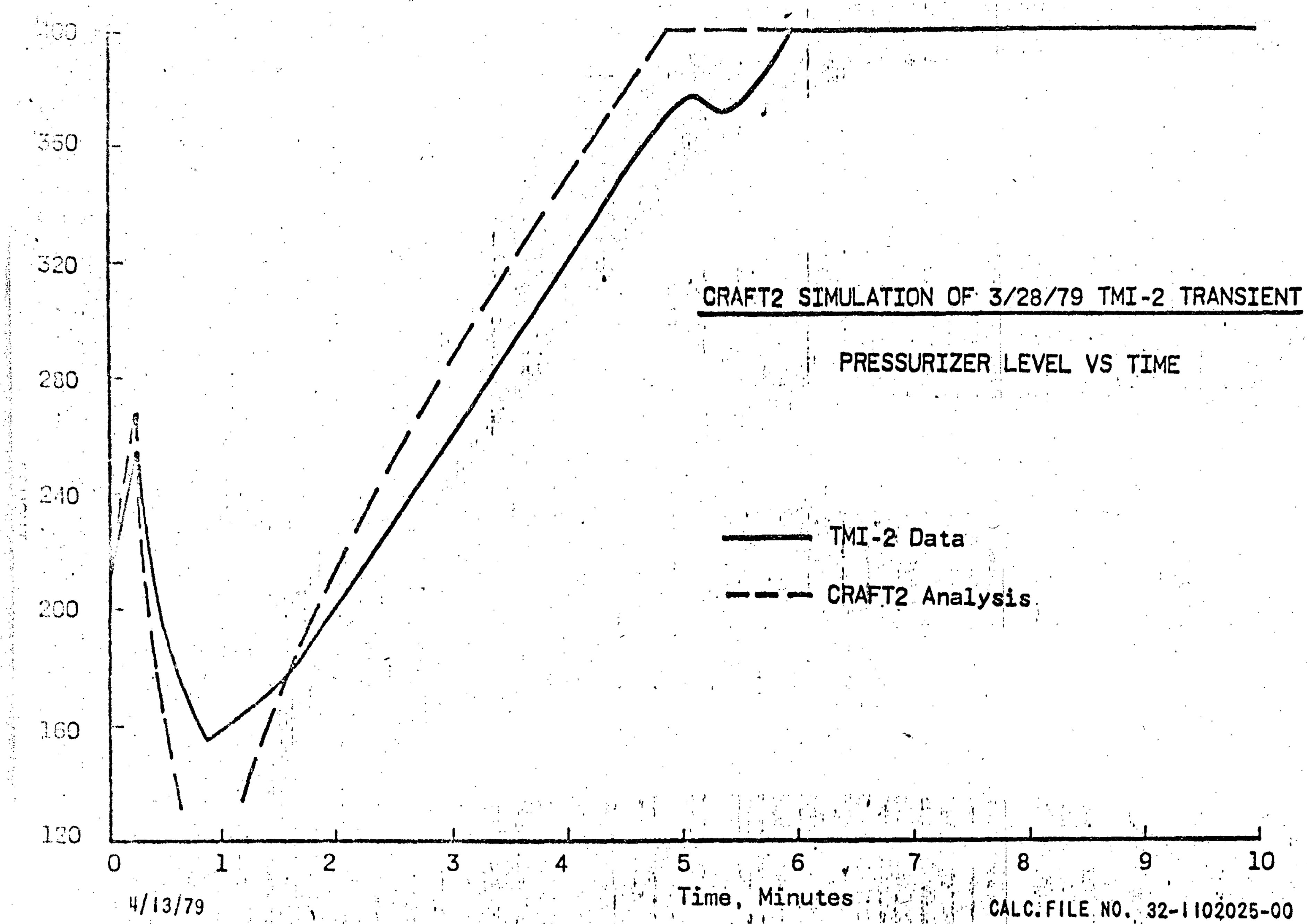
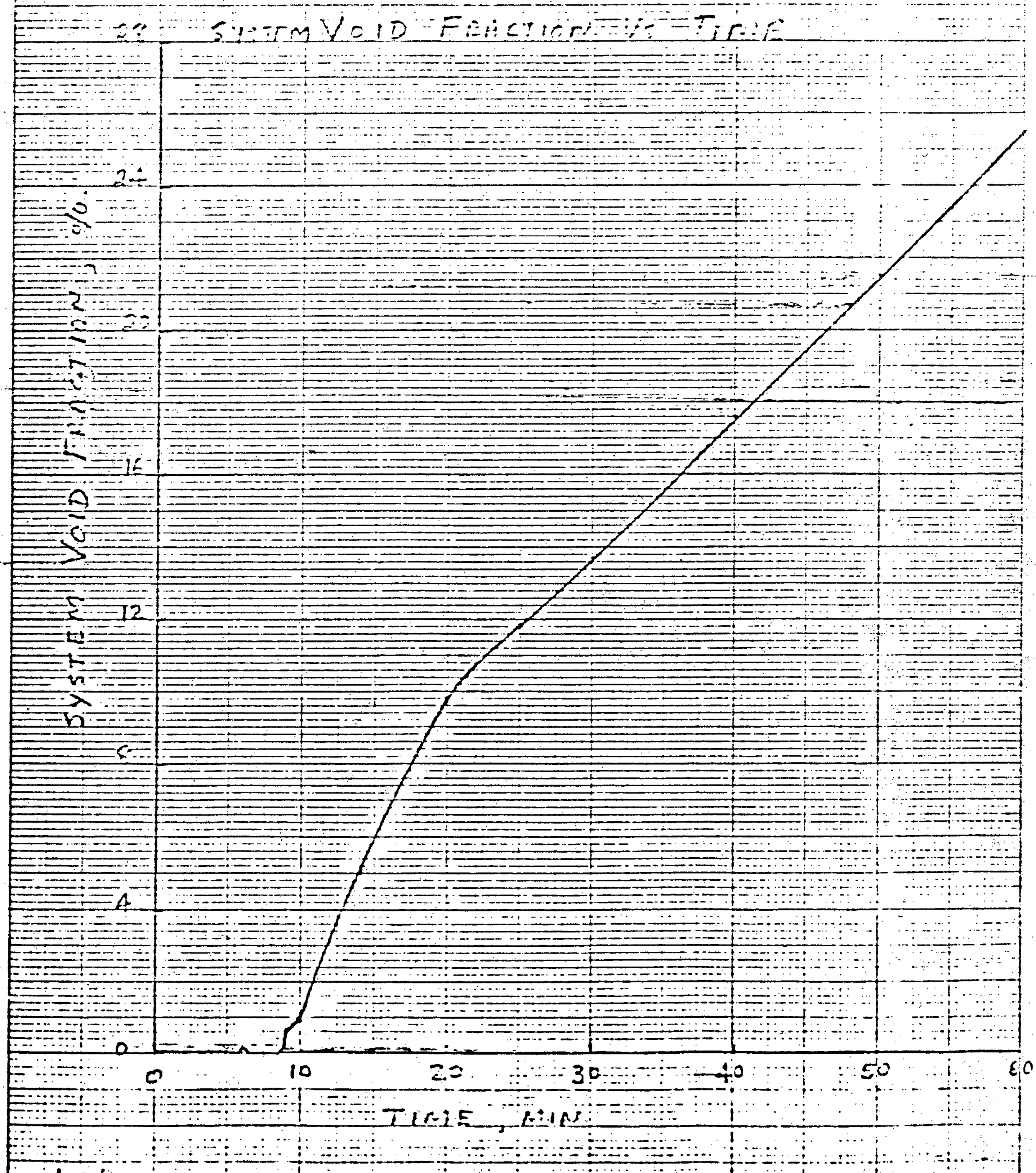

400
360
320
280
240
200
160
120
0
1
2
3
4
5
6
7
8
9
10
CRAFT2 SIMULATION OF 3/28/79 TMI-2 TRANSIENT
PRESSURIZER LEVEL VS TIME
TMI-2 Data
CRAFT2 Analysis
Time, Minutes
4/13/79
CALC. FILE NO. 32-1102025-00

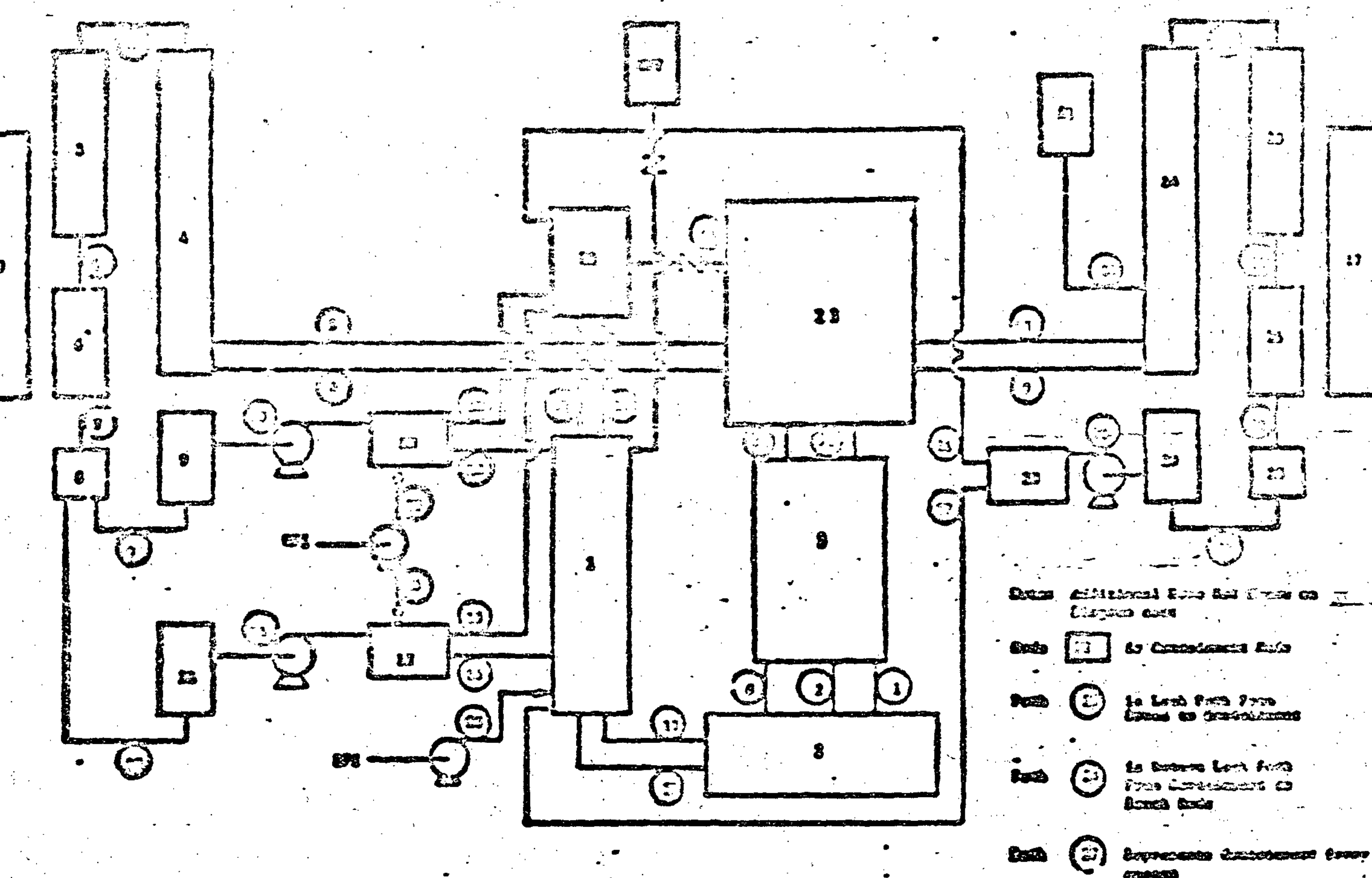
FIGURE 10


SYSTEM VOID FRACTION VS TIME
SYSTEM VOID FRACTION, %
0
4
8
12
16
20
24
28
0
10
20
30
40
50
60
TIME, MIN
4/18/79

ATTACHMENT 3

Case No. 5 Results

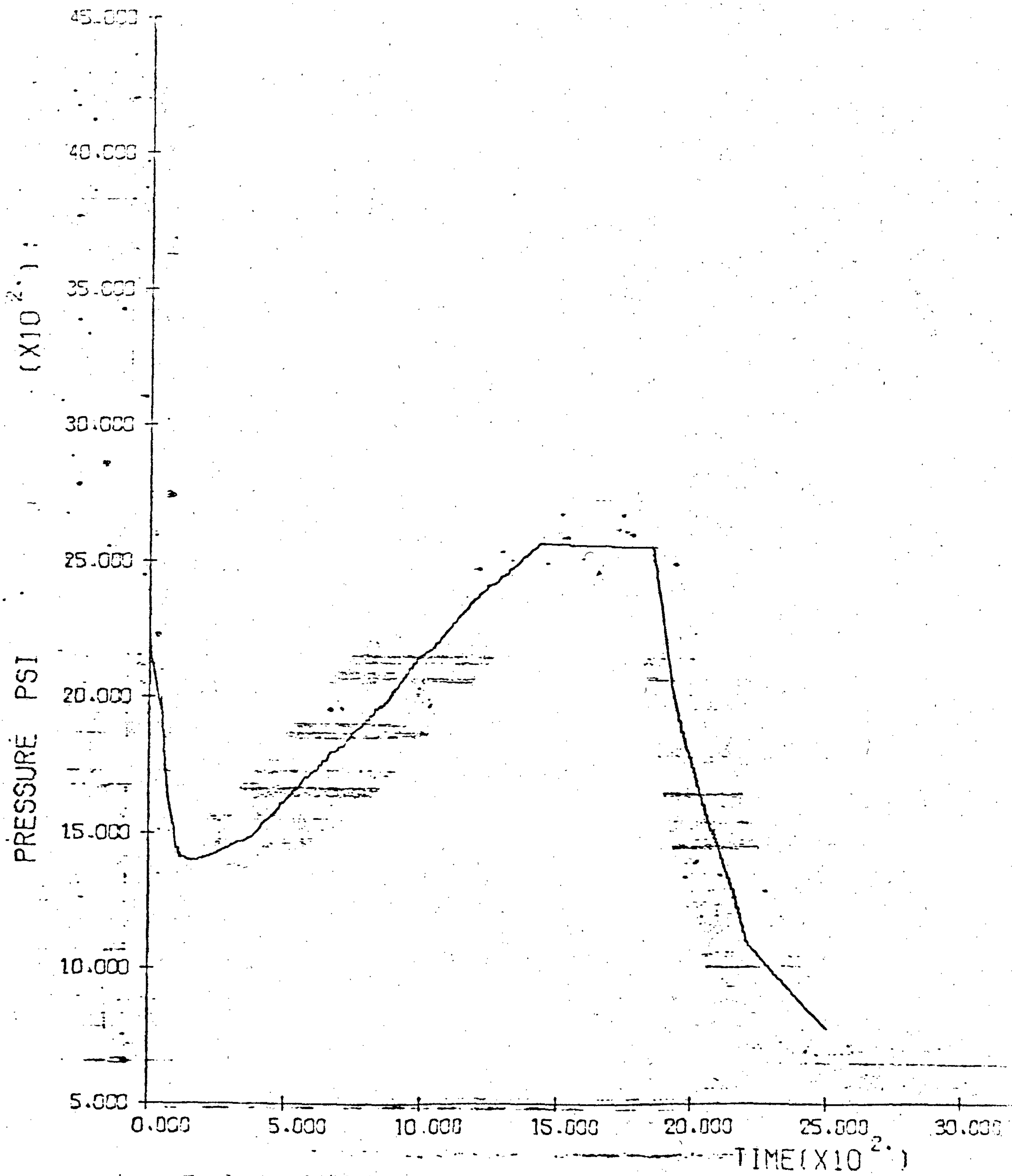
Figure 1. [illegible] Noding Diagram for Small Breaks



Node No.	Identification	Path No.	Identification
1	Downcomer	1,2	Core
2	Lower Plenum	3,4,18,19	Hot Leg Piping
3	Core	5,20	Hot Leg, Upper
4,14	Hot Leg Piping	6,21	SG Tubes
5,15	SG & Upper Head	7,22	SG Lower Head
6,16	Steam Generator Tubes	8	Core Bypass
7,17	Secondary, SG	9,10,24	Cold Leg Piping
8,18	SG Lower Head	10,16,25	Pumps
9,10,19	Cold Leg Piping	11,12,13,16,25,27	Cold Leg Piping
10,12,20	Cold Leg Piping	17,31	Downcomer
11	Upper Downcomer	13	HPI
21	Pressurizer	13,30	Upper Downcomer
22	Containment	30	Pressurizer
23	Upper Plenum	32	Vent Valve
		33,34	Leak & Return Path
		35,36	HPI
		37	Containment Sprays

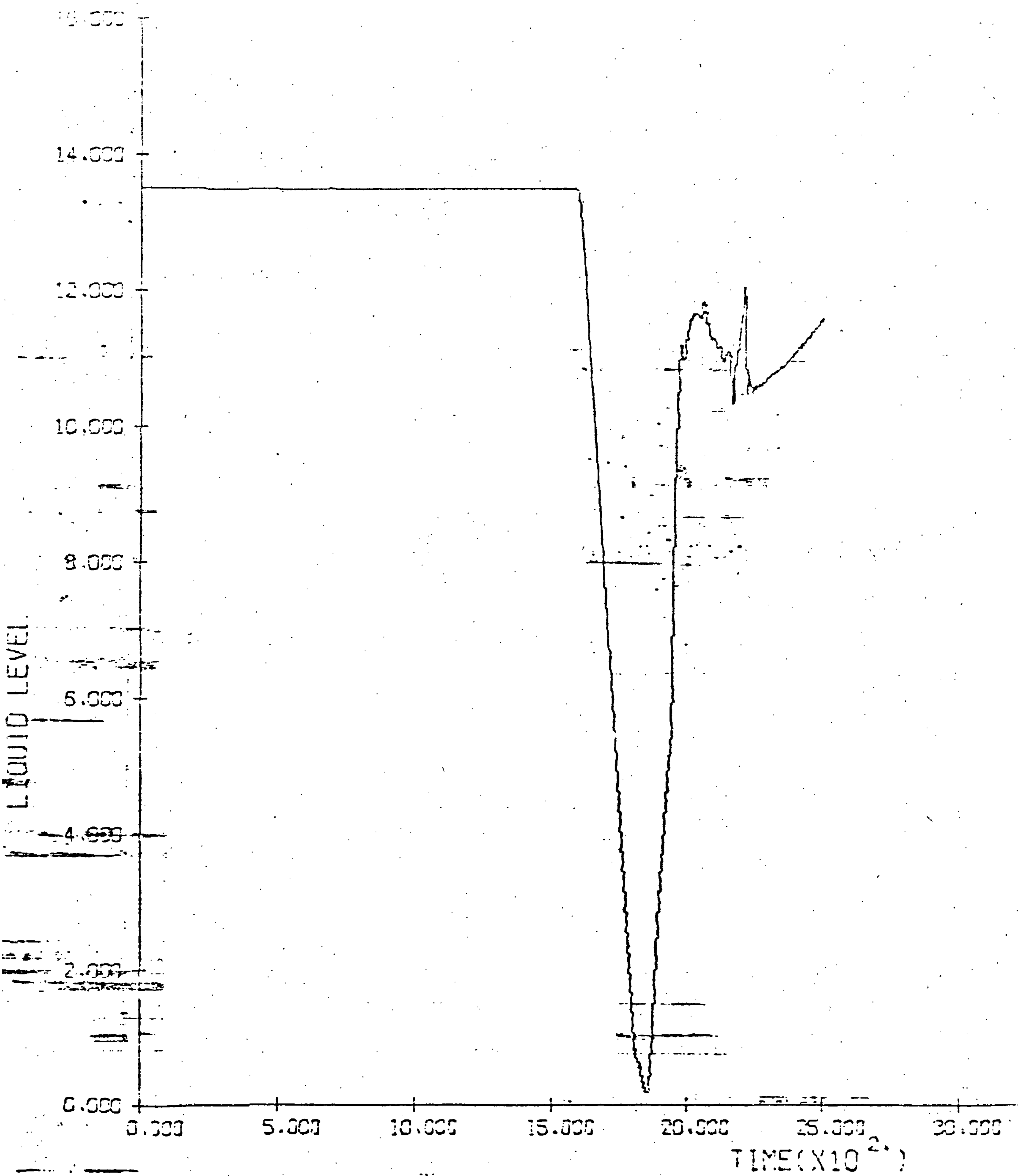
BC [illegible]
4/18/79

FIGURE 12



10HT .010 FT2-NO AUX FEED

NODE



10HT .010 FT2-NO AUX FEED

NODE 3

FIGURE 14

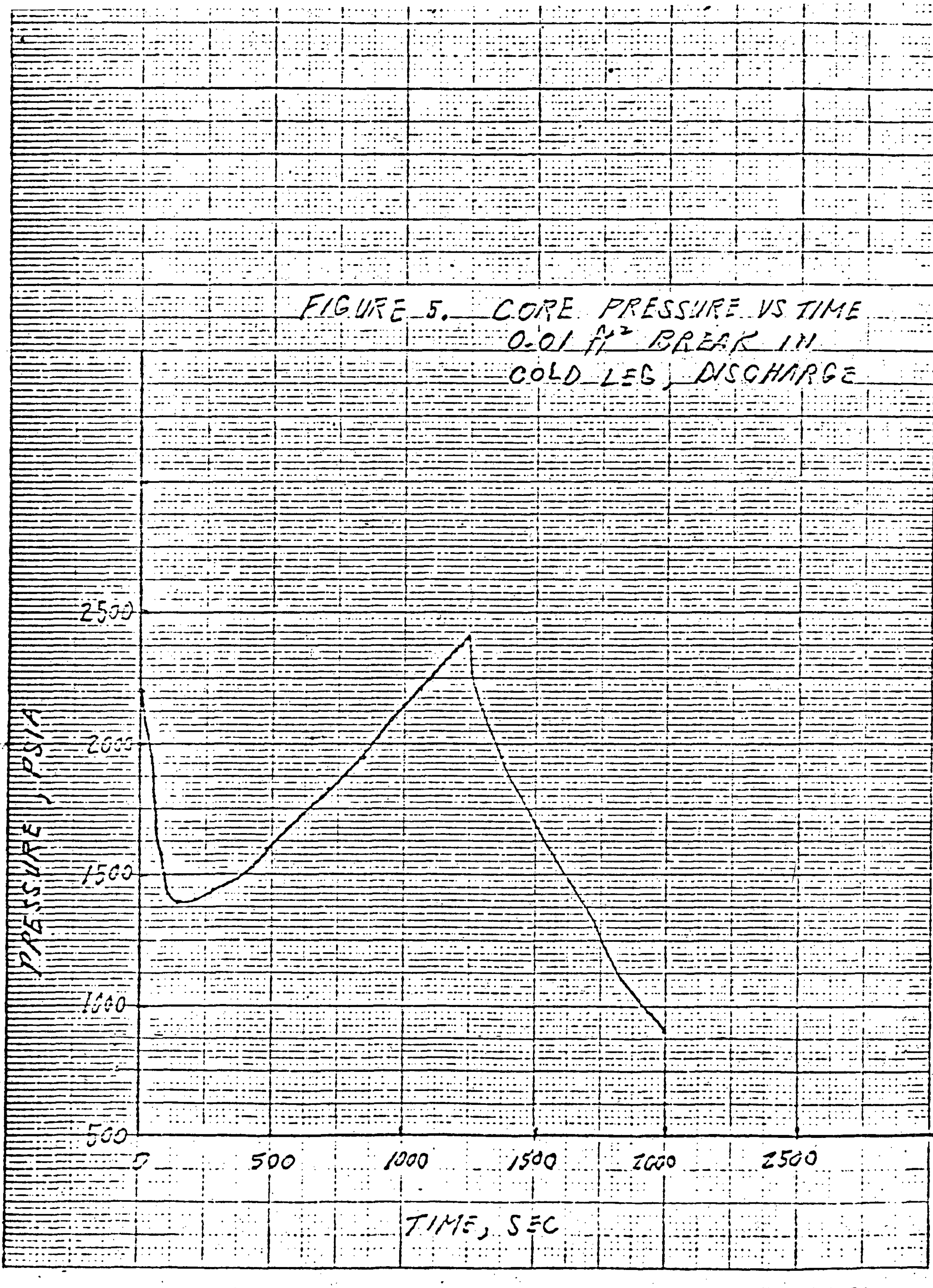


FIGURE 5. CORE PRESSURE VS TIME
0.01 ft² BREAK IN
COLD LEG, DISCHARGE
PRESSURE, PSIA
2500
2000
1500
1000
500
0
500
1000
1500
2000
2500
TIME, SEC

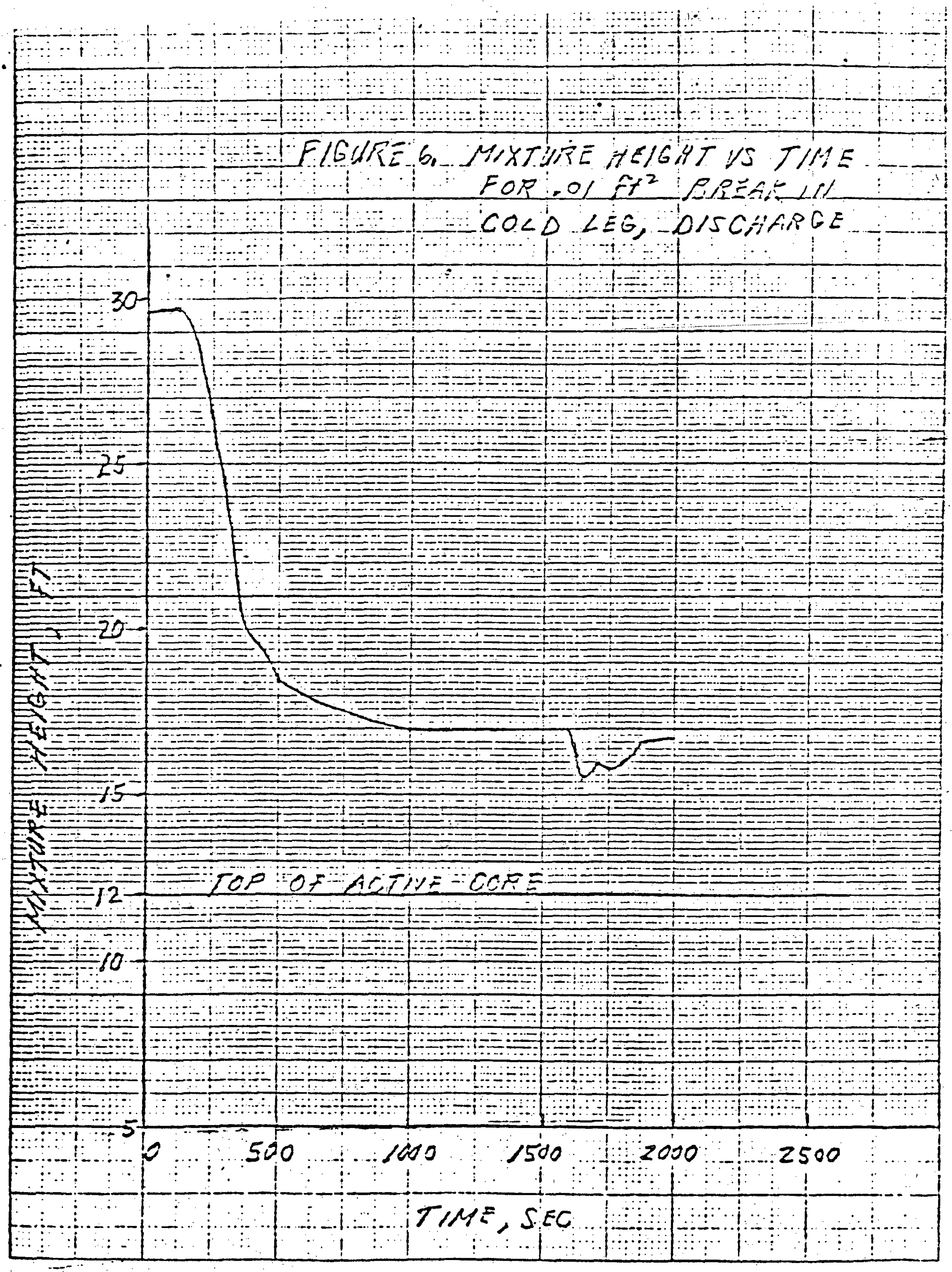


FIGURE 6. MIXTURE HEIGHT VS TIME
FOR .01 FT² BREAK IN
COLD LEG, DISCHARGE
30
25
20
15
12
10
5
TOP OF ACTIVE CORE
MIXTURE HEIGHT, FT
0
500
1000
1500
2000
2500
TIME, SEC

Reference: Letter from J. H. Taylor to R. J. Mattson, April 25, 1979.

Case No. 2 Results

Pressure vs. Time

LOFW w/ Stuck Open PORV

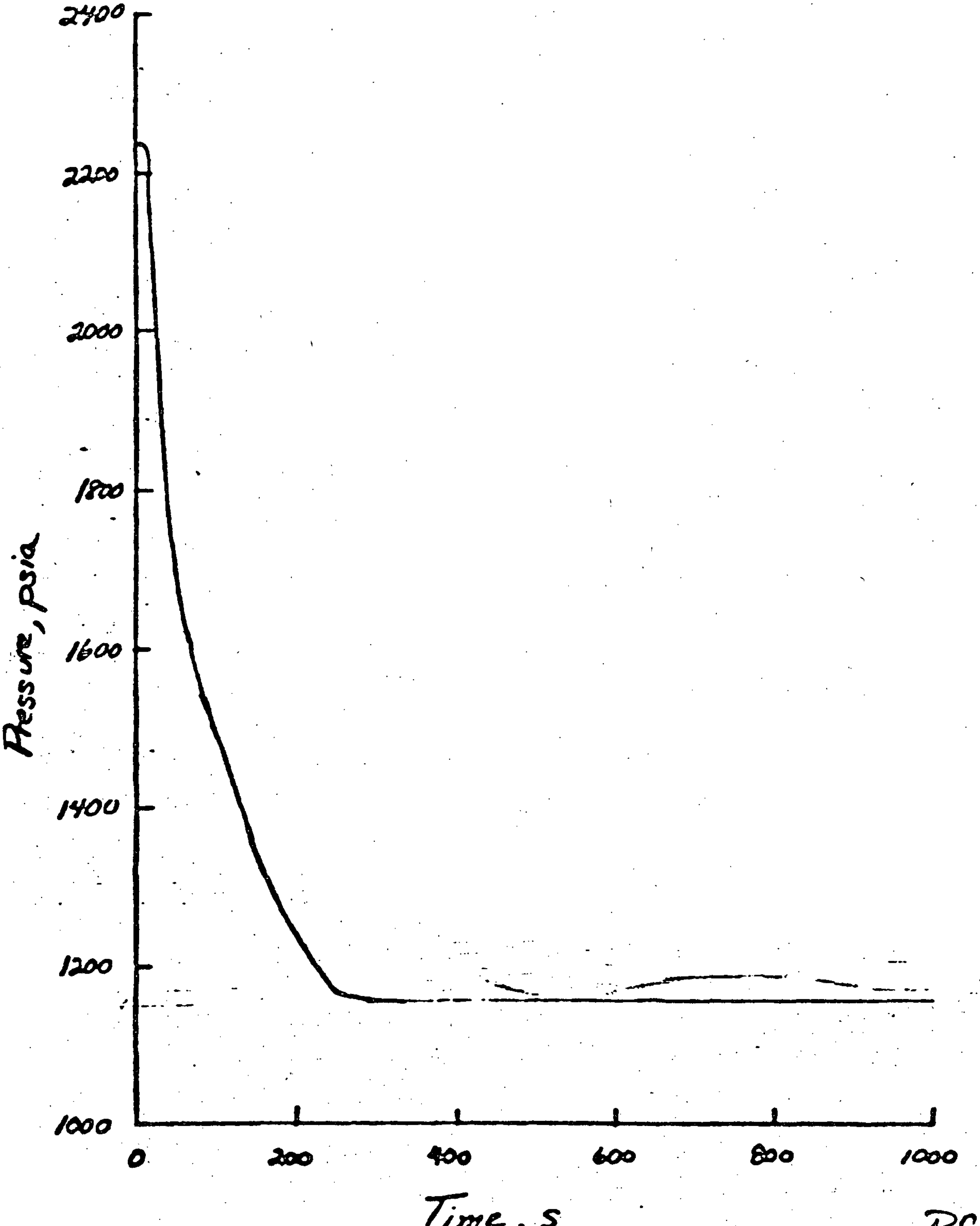


FIGURE 17

R.C. [illegible]
4/1/[illegible]

Pressurizer Level vs. Time

LOFW w/Stuck Open PORV

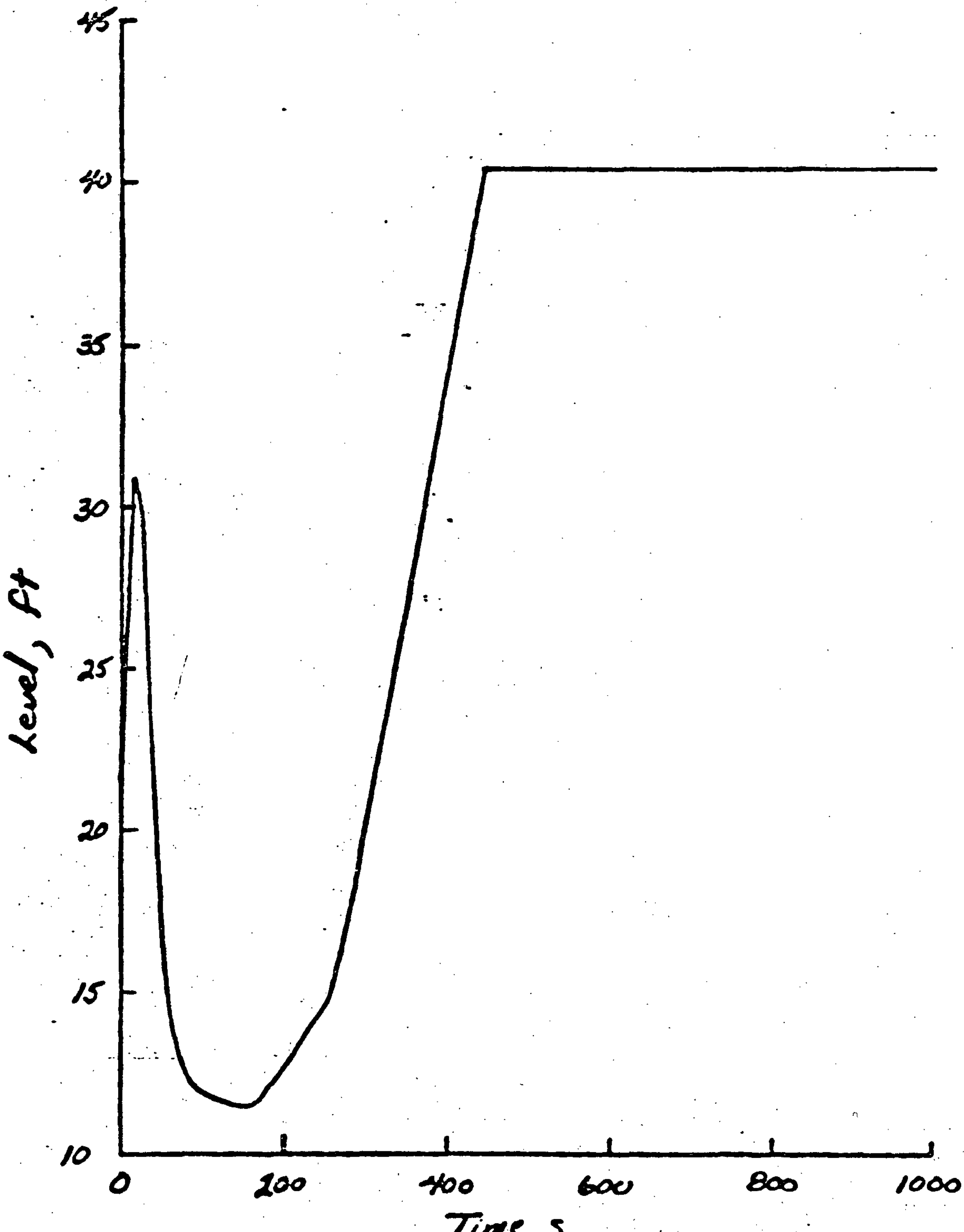


FIGURE 18

leak Flow vs. Time

LOFW w/ Stuck Open PORV

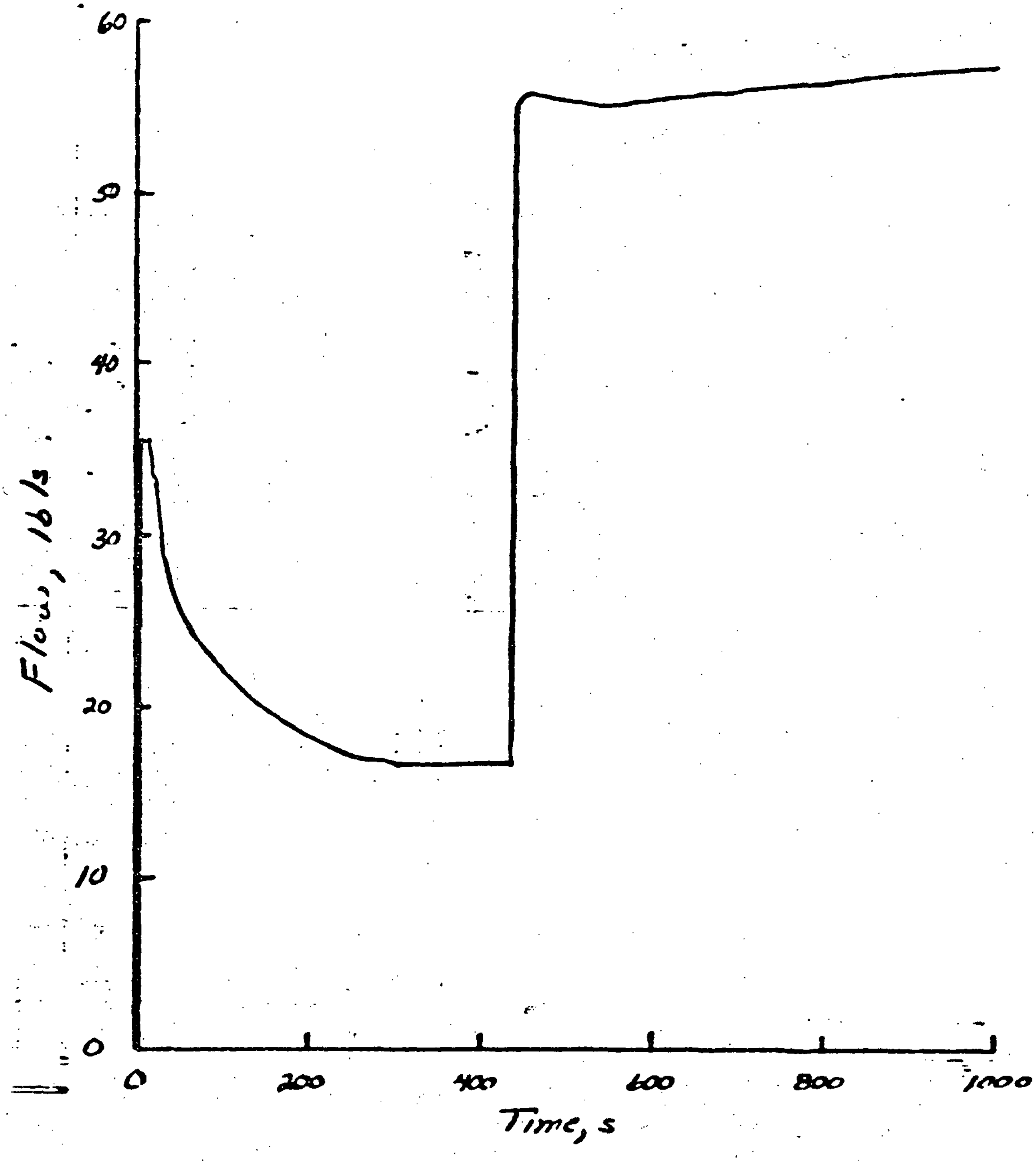


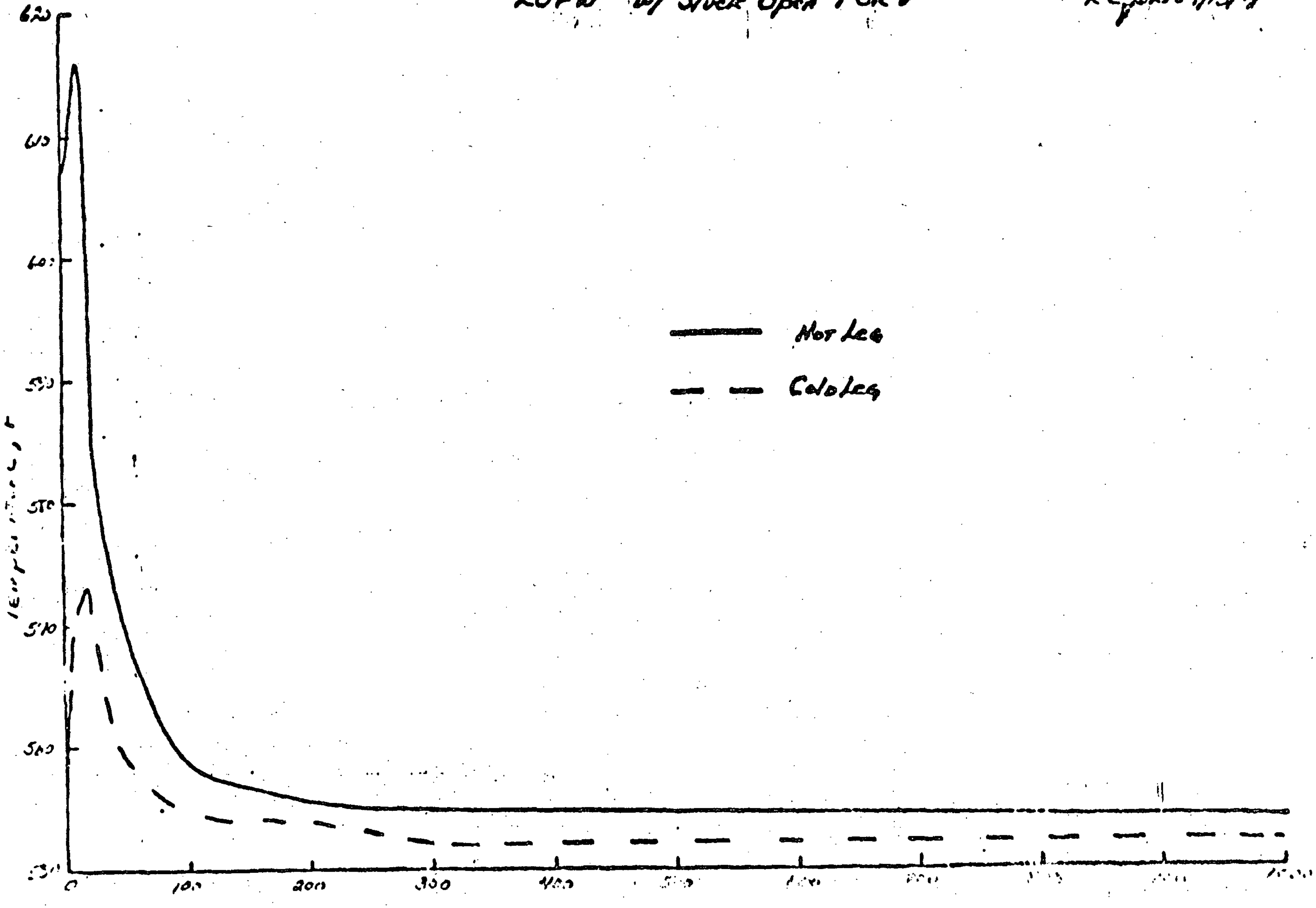
FIGURE 19

R.C. Jones
4/18/79

Hot and Cold Leg Temperatures vs. Time

LOFW w/ Stuck Open PORV

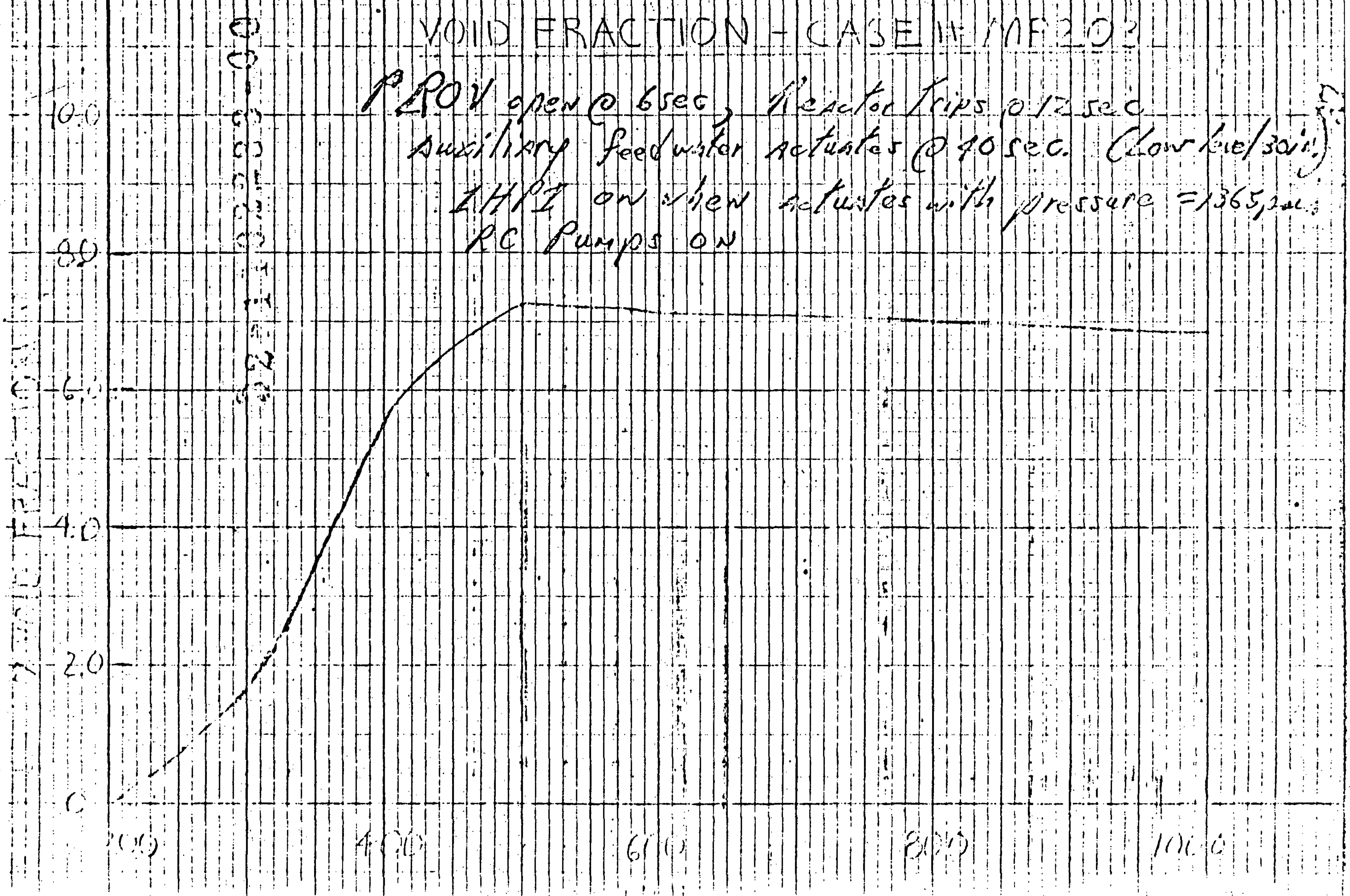
RC Jones 4/13/79



K+E 10 X 10 TO THE INCH • 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 0780

LOFW Transient with offsite power



Reference: Letter from J. H. Taylor to
R. J. Mattson, April 25, 1979.

Case No. 7 Results

Pressure vs. Time

Stuck Open PORV-SBA

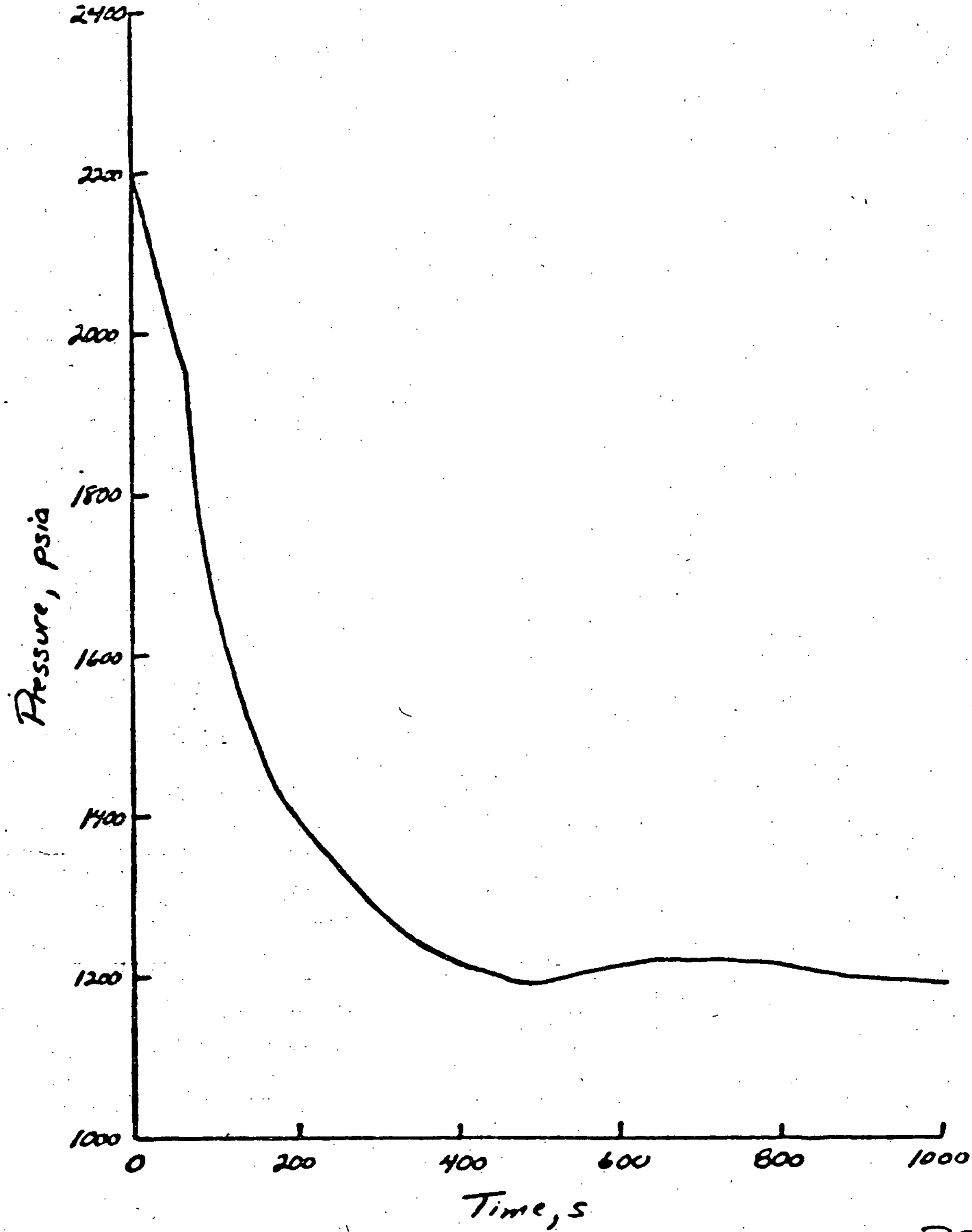


FIGURE 22

R.C. [illegible]
4/10/79

PRESSURIZER LEVEL VS TIME

Stuck Open PORV-SBA

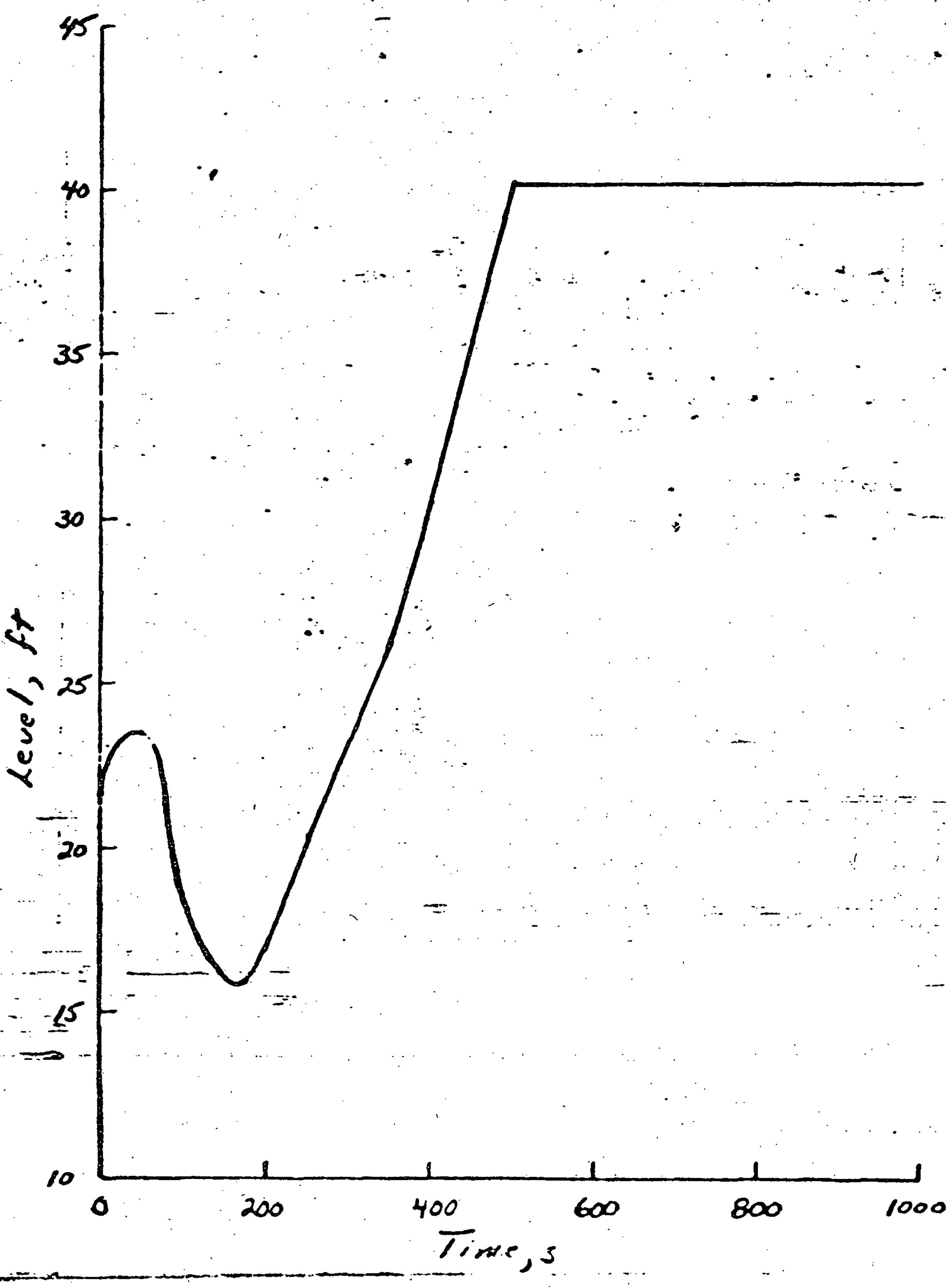


FIGURE 23

LEAK Flow vs. Time

Stuck Open PORV - SBA

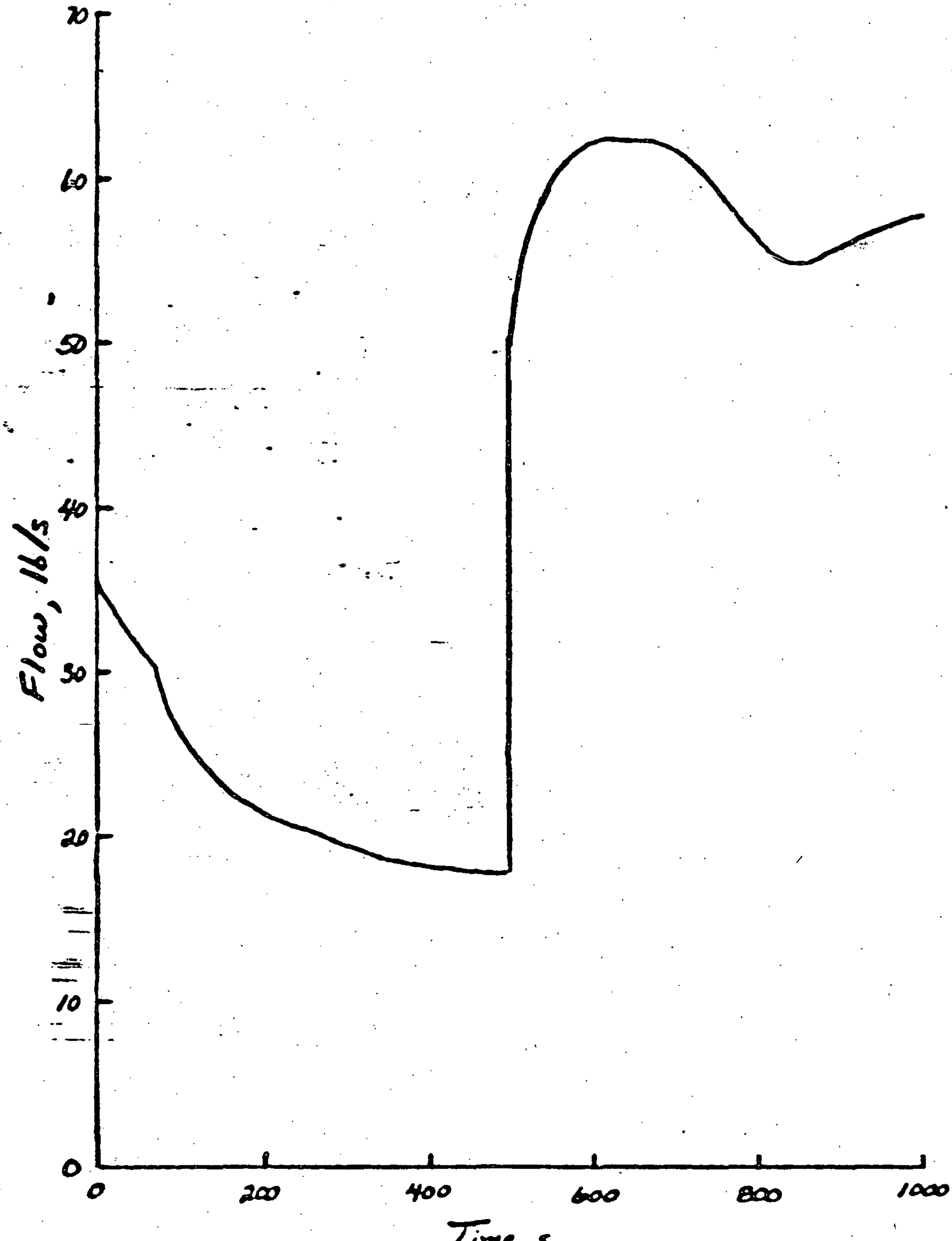


FIGURE 24

R.C. [illegible]
4/18/79

Core Flow vs. Time

Stuck Open PORV - SBA

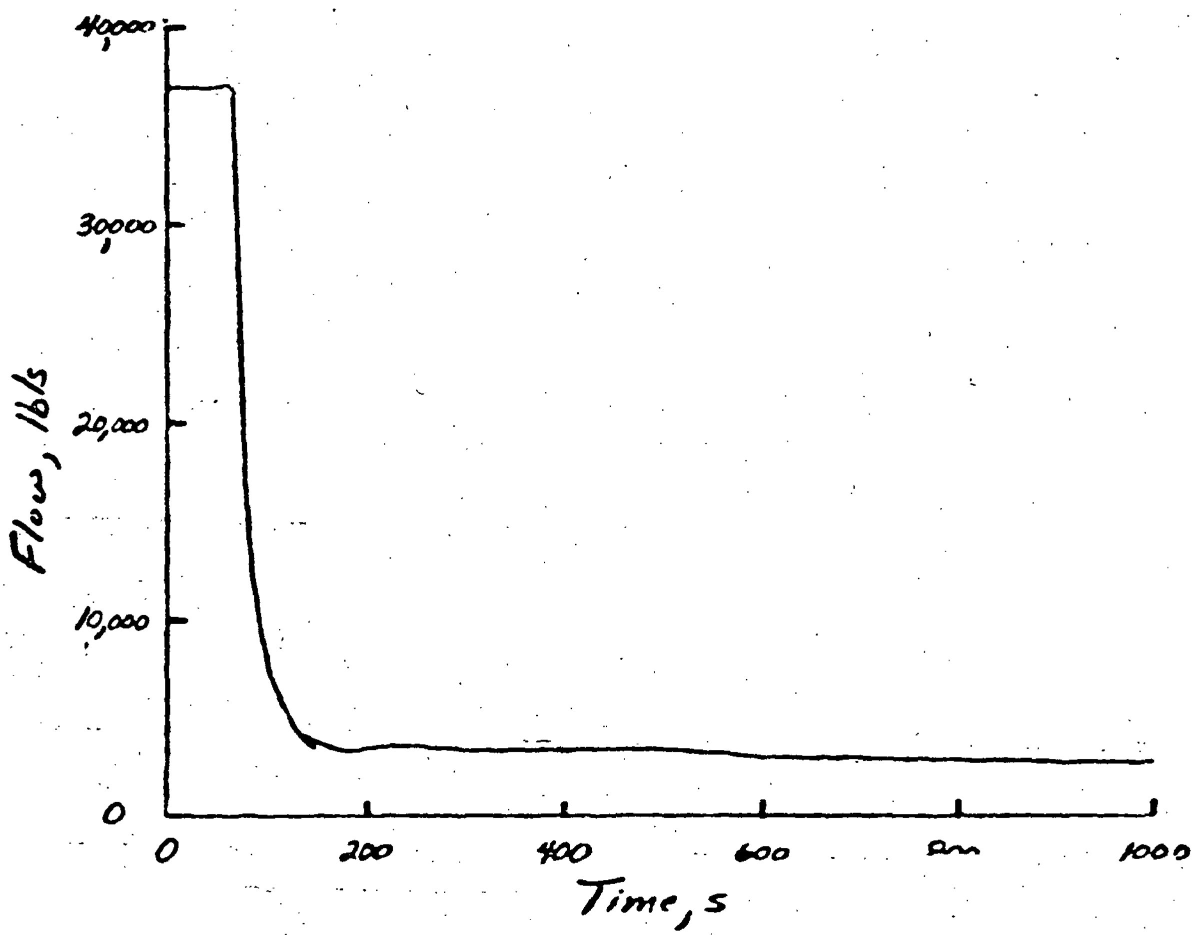
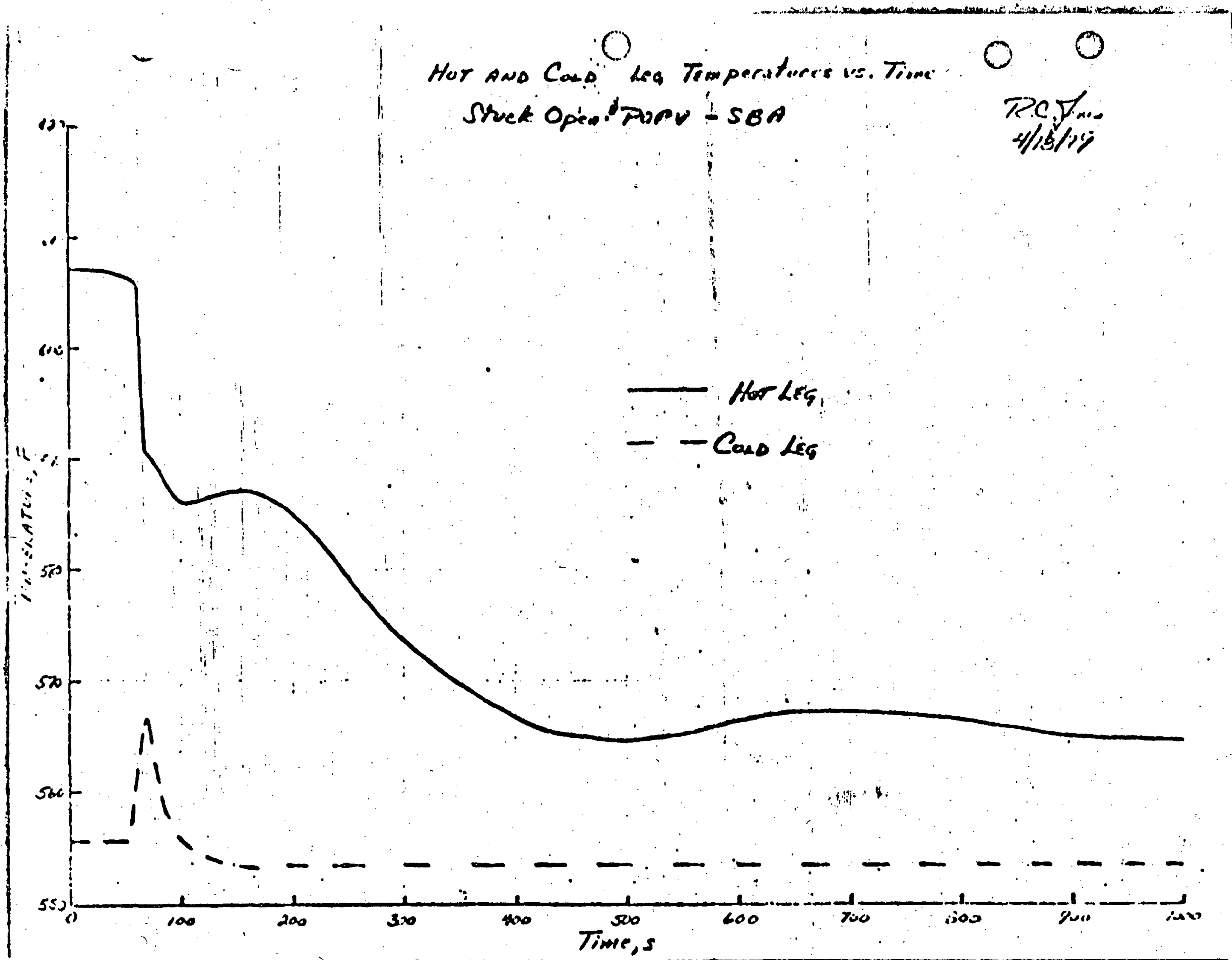


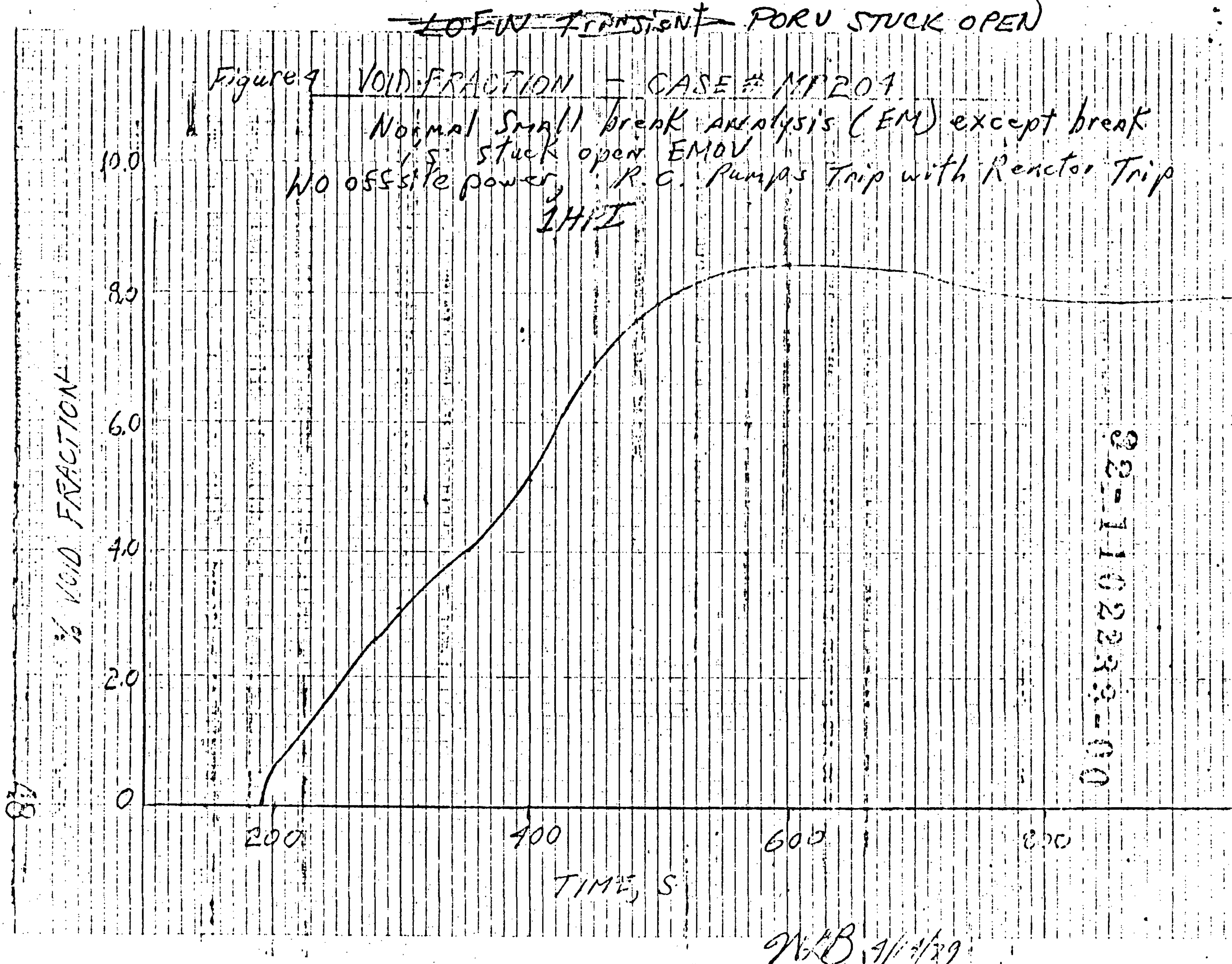
FIGURE 25

P.C. Jones
4/18/79



Hot and Cold Leg Temperatures vs. Time
Stuck Open PORV - SBA
R.C. J
4/13/79
Hot Leg
Cold Leg
Time, s
100
200
300
400
500
600
700
900
560
570

FIGURE 26



~~LOFW Transient~~ PORV STUCK OPEN
Figure 4 VOID FRACTION — CASE # MP201
Normal Small break analysis (EM) except break is stuck open EMOV
W/O offsite power, R.C. Pumps Trip with Reactor Trip
1 HPI
% VOID FRACTION
10.0
8.0
6.0
4.0
2.0
0
200
400
600
800
TIME, S
WKB 4/1/79

Reference: Letter from J. H. Taylor to R. J. Mattson, April 25, 1979.

Case No. 1 Results

Table 1. Sequence of Events 102045-00

1. Main feedwater pumps trip at time = 0.0 seconds.

   Note: All RC pumps remain powered throughout the transient.

2. Pressurizer EMOV valve open at 6.0 seconds and remains open (stuck).

3. Reactor scrams at 12.0 seconds.

4. Auxiliary feedwater starts at 40.0 seconds after loss of main feedwater (auxiliary feedwater level is set at 30 inches).

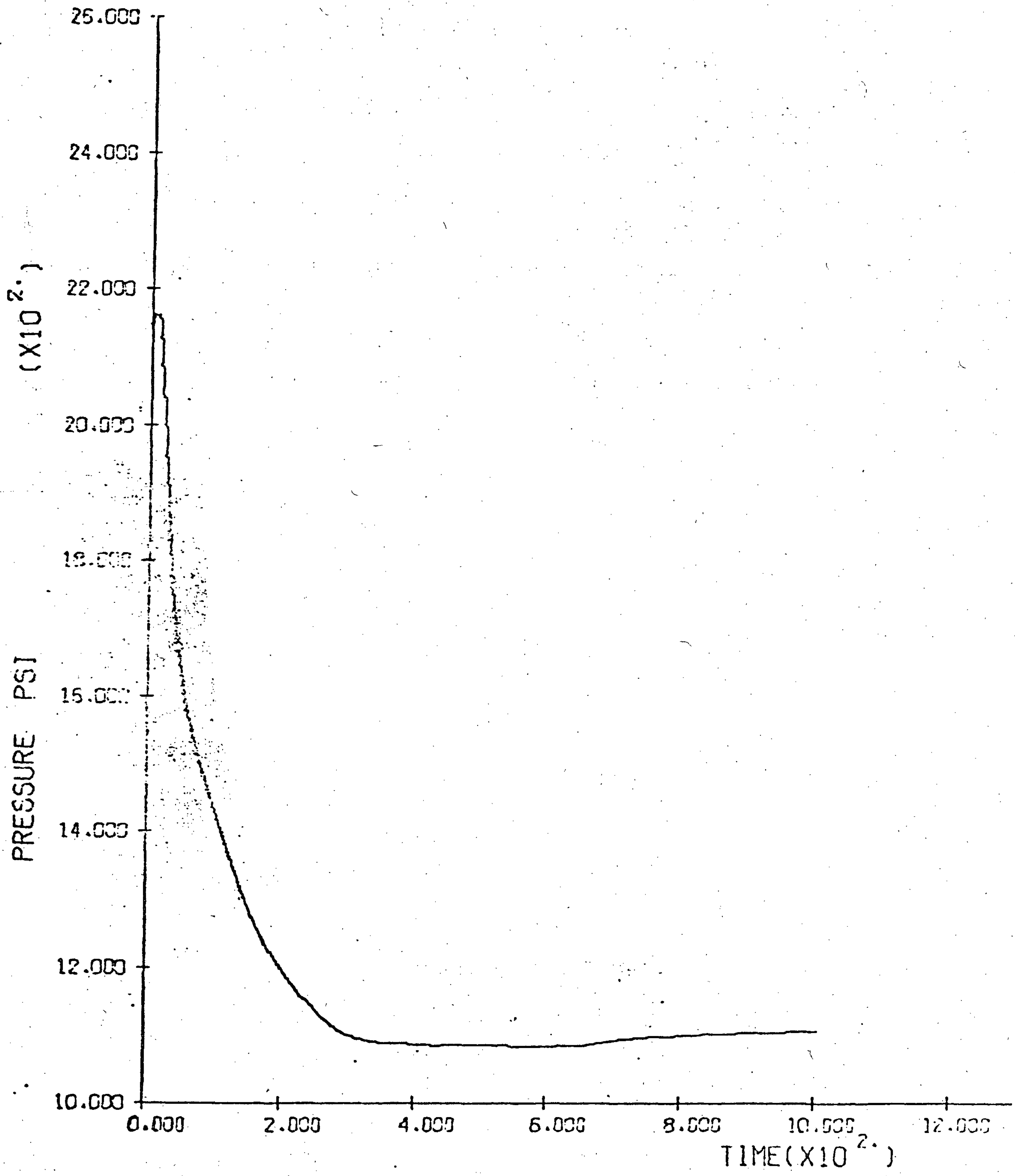
5. At 1365 psia, ESFAS actuation occurs, resulting in two HPI pumps injecting into the cold legs at 155 seconds.

6. Long term cooling established at 155 seconds.

7. Pressurizer goes solid at approximately 425 seconds.

FIGURE 28

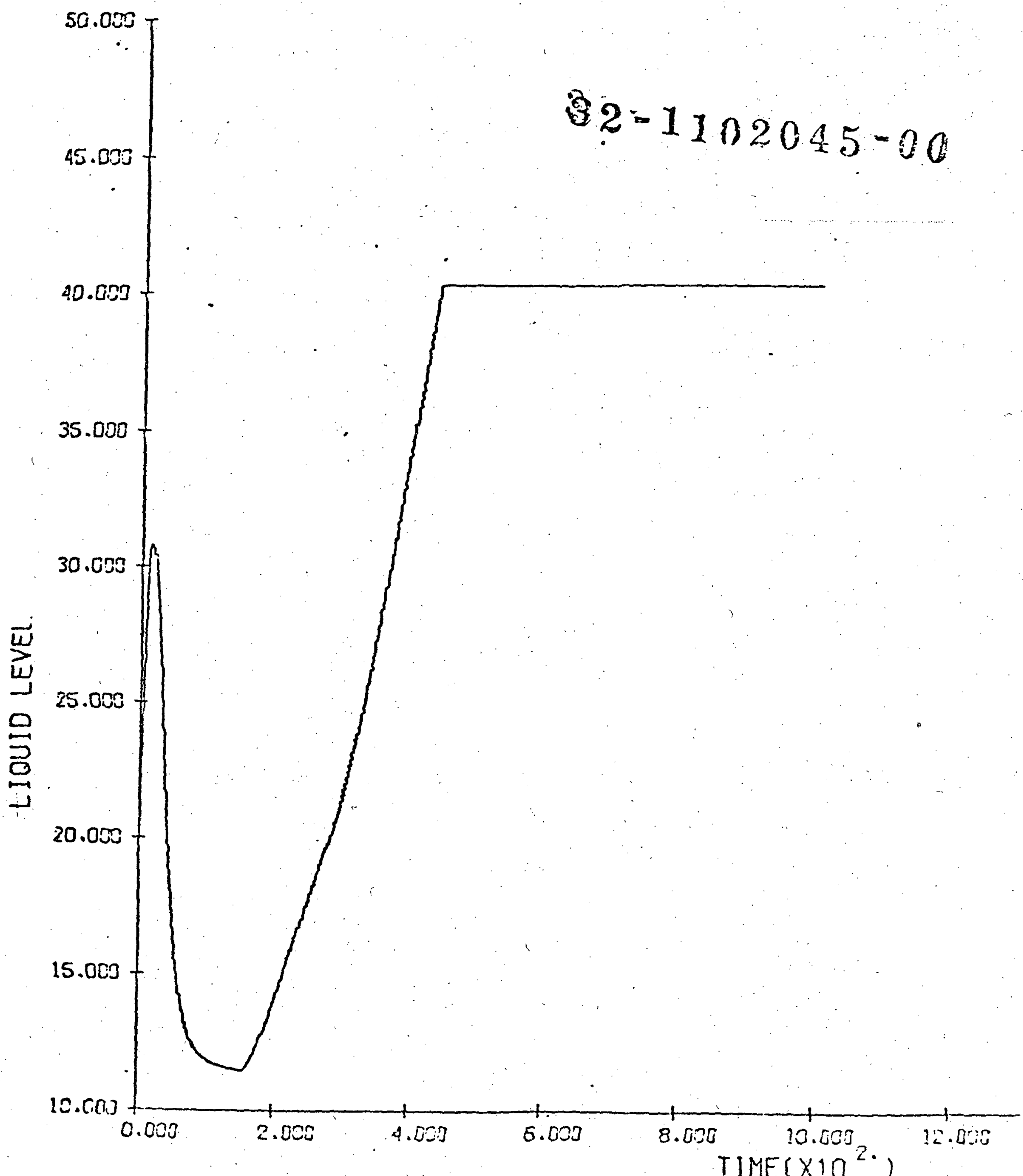
Figure 2. Pressurizer pressure vs. time



0200

FIGURE 29

Figure 3. Liquid Level in pressurizer vs. time



0200

FIGURE 30

0069 NODE 21

APPENDIX V

4.5 COLD SHUTDOWN CAPABILITY

EXCERPT FROM TMI-1 FSAR

The adequacy of the borated water storage tank as an interim heat sink for the Three Mile Island Nuclear Station, Unit 1, reactor coolant system has been evaluated for the following set of assumptions:

a. Steam line break occurs inside the intermediate or turbine building during rated power operation

b. Reactor trips

c. Loss of all feedwater to both steam generators occurs

d. Loss of off-site power occurs

In addition to this set of assumptions, this evaluation is valid for any situation where reactor coolant system energy removal through the steam generators is no longer available.

There are three primary areas of concern for this condition. These areas are prevention against core uncovering, protection against excessive reactor building pressure, and the ability to achieve cold shutdown conditions.

The B&W digital computer code CRAFT (10) was used to determine the characteristics of this accident with regard to core uncovering and mass energy releases to the containment. The mass and energy release data from CRAFT was used in the digital computer code CONTEMPT (11) for reactor building pressure calculations. The assumptions and results of the analysis are summarized in Table 6. A single steam generator blowdown was considered as the most conservative case since for a double blowdown the HPI pump would be started almost instantaneously on low reactor coolant system pressure actuation (1500 psig) meaning a lower probability of core uncovering.

Core uncovering is prevented by pumping water from the borated water storage tank via the makeup and purification system (HPI) into the reactor coolant system. With one makeup and purification (HPI) pump started 15 minutes after the break, the minimum coolant level in the reactor vessel occurs at approximately 140 minutes and at no time falls below the top of the core. Operator action is assumed to occur 15 minutes after the break in starting the makeup and purification pump (high pressure injection).

The building pressure increases during the transient as boiloff occurs through the pressurizer safety valves (2515 psia). Assuming the boiloff goes directly to the building atmosphere with no credit for the quench tank, the building pressure reaches the reactor building cooler and high pressure injection setpoint (4 psig) 38 minutes after the break. With one building cooler operative at this time, the building pressure reaches a maximum value of 24 psig and never exceeds the design pressure limit. Furthermore, the reactor spray actuation setpoint (30 psig) is not reached and a single building cooler provides adequate protection throughout the transient against excessive reactor building pressure.

High pressure injection of BWST water continues until the BWST is depleted (approximately 24 hours assuming one HPI pump is operating.) At this time further cooldown is achieved by using the decay heat (low pressure injection) pumps drawing from the reactor building sump to supply suction to the makeup and purification (HPI) pumps. The sump recirculation continues until the decay heat removal system (LPI) can be actuated to reduce the system to cold shutdown. Cold shutdown is then achieved by venting the system pressure and actuating the decay heat removal system to recirculate the reactor coolant through the decay heat coolers.

5.0 EMERGENCY PROCEDURES

The emergency procedures below are general in nature since it is deemed appropriate to allow for assessment of the incident prior to ultimately bringing the reactor to cold shutdown.

5.1 SYMPTOMS (STEAM LINE BREAK)

a. Rapid decrease of secondary steam pressure.

b. A steam line break detection system actuated alarm.

c. Megawatts generated reducing rapidly.

d. Decrease in pressurizer level, reactor coolant pressure, and cold leg temperature.

e. For a rupture outside the reactor building noise will be heard in the control room or a report made from personnel outside the control room.

5.2 IMMEDIATE ACTION

a. Automatic Action

1. Steam line break feedwater shut-off system actuates ($\leq$ 600 psi) and the low load control valves FW-V-16A and 16B, main feedwater valves FW-V-17A and 17B, and emergency feedwater valves EF-V-30A and 30B close.

2. Reactor trips

3. Turbine trips

4. High pressure injection initiates if low reactor coolant pressure of 1500 psig or reactor building pressure of 4 psig is reached.

5. Reactor building cooler actuation due to 4 psig in the reactor building.

b. Manual Action

1. Verify that the reactor has tripped; if not, trip it.

2. Verify the turbine has tripped (main stop valves closed); if not, trip it.

3. Notify shift foreman that the reactor has tripped.

4. Determine which steam generator has suffered the rupture from the steam line break detection system in the control room.

5. Verify that low load control valves FW-V-16A or 16B, main feedwater valves FW-V-17A or 17B, and emergency feedwater valves EF-V-30A or 30B on the affected steam generator are in the closed position.

6. Initiate emergency feedwater supply to the unaffected steam generator.

7. Determine if the makeup and purification system (high pressure injection) has started. Manually initiate it if both steam generators are inoperative and pressure setpoints have been exceeded.

5.3 LONG TERM ACTION (Emergency Feedwater)

If there are indications that the emergency feedwater system is not working properly, enter the intermediate building as soon as possible. Inspect the emergency feedwater system to determine if it has experienced any damage. Line up the undamaged emergency systems to supply water to the unaffected steam generator. Open steam dump valves on the unaffected steam generator. The valves may have to be operated using handwheels if the cabling has been damaged by the break. When the emergency feedwater valves have been lined up, start the emergency feedwater pumps. Throttle the feedwater control valves to maintain high level in the steam generator.

When the reactor coolant system pressure has decreased sufficiently initiate the decay heat removal system.

5.4 LONG TERM ACTION (Feed and Bleed)

When the contents of the borated water storage tank are depleted as determined from the borated water storage tank low-low level alarm in the control room, shift suction of high pressure injection from the borated water storage tank to the reactor building sump by opening valves DH-V-7A and 7B, DH-V-6A and 6B, and closing valves DH-V-5A and 5B (all remotely controlled from the control building).

When reactor coolant system temperature is below 440 F, close the core flood line discharge valves CF-1A and 1B, secure the makeup and purification pump (HPI), and depressurize the reactor coolant system by opening the pressurizer electromatic relief valve or pressurizer sample line (both remotely controlled from the control building). To initiate decay heat removal, open valves DH-1, DH-2, and DH-3 (normal decay heat let-down line).

6.0 SUMMARY AND CONCLUSIONS

The results of this design review are summarized as follows:

a. A rupture of the high energy piping systems is considered highly unlikely. The systems have been conservatively designed in accordance with the criteria in the B31.1.0 Code for Power Piping. Materials, fabrication, and quality assurance requirements of the code have been utilized. In addition, the main steam piping has been subject to 100 percent radiography of welds from the steam generators to the turbine stop valves, and the

TABLE 6

CHRONOLOGY OF EVENTS FOR HIGH ENERGY PIPE BREAK

Time (seconds)	Event
0	Double-ended break of a 24 inch diameter steam line on the secondary side
1	Reactor trip on variable low pressure; turbine stop valves close isolating the unaffected steam generator
47	Damaged steam generator blows dry
450	Unaffected steam generator provides no more heat sink; minimum system pressure of about 1550 psia is reached
900	Operator action starts one HPI pump
1200	Primary loop becomes solid with subcooled water; pressurizer code relief valve opens at setpoint of 2515 psia
2300	Reactor building cooler actuation setpoint of 4 psig is reached
5700	Steam first appears in the core
8500	Minimum coolant level in reactor vessel is reached; core remains covered
8800	Containment building pressure reaches the maximum value of 24 psig

A preliminary assessment has indicated that the double-ended rupture of up to 3 tubes during a LOCA would not seriously impair the capability to reflood and cool the core in accordance with the conservative requirements of Appendix K to 10 CFR Part 50.

QUESTION 5

What is the maximum secondary system pressure developed after turbine trip with first subsequent random failure being loss of main feedwater flow control leading to flooding of super-heat section of steam generators. Assume turbine trip without bypass (loss of condenser vacuum).

Response to Question 5

The maximum secondary side pressure developed, assuming turbine trip without bypass and a subsequent loss of main feedwater flow control, is equal to the setpoint of the main steam safety valves. There are two banks of safety valves. The "high" bank setpoint is about 1315 psia which includes 3% accumulation. The maximum allowable steam generator pressure is 1375 psia.

QUESTION 6

Does applicant know that time-dependent levels will occur in pressurizer, steam generator and reactor vessel after a relatively small primary coolant break which causes coolant to approach or even partly uncover fuel pins? What does operator do in respect to interpreting level in pressurizer?

During primary system refill from high pressure injection pumps there is some period when neither condensation nor natural convection is present to effect heat transport to secondary side. How is transition to natural convection <u>without assistance from primary coolant pumps</u> obtained.

Response to Question 6

There are two overriding concerns with any LOCA:

(1) Initial removal of fuel-stored heat.

(2) Continuous removal of core fission product decay heat.

For small breaks, fuel-stored heat is removed during the first few seconds of blowdown. The B&W ECCS system, using internal vent valves, precludes the interruption of decay heat removal for all accidents within the range of relatively small breaks (break size $<0.01\ ft^2$). Break location, ECCS injection, coolant phase separation, Reactor Coolant System (RCS) mixture levels and steam generator condensation have been considered in arriving at this conclusion.

As we understand the question, the concern is related to possible interruption of steam condensation within a steam generator due to refilling of the primary system. In general, such a situation can occur only at extended times during the final recovery stage of a LOCA when steam condensation is no longer required. However, even if this situation occurred earlier in time, the performance of the vent valves would be to equalize water levels between the hot and cold regions of the primary system, thereby assuring continuous fluid coverage of the core with no adverse consequences.

This is substantiated by a more detailed examination of the fluid conditions during a relatively small LOCA. Such an accident can be viewed as a very slow transient during which, at any particular time, the system is not meaningfully different from steady-state conditions. The RCS can then be properly described as a sealed manometer. For the B&W system, because of the vent valves, this manometer is double looped as illustrated in Figure 6-1 with important volumes identified by letters.

Many experiments have been run which show that as long as a fluid (quality less than, say, 70%) covers the core, no adverse core temperature excursion can occur at decay heat power levels. Thus, the design problem associated with small LOCAs is to achieve steady mass and energy balances which assure that the core remains covered. This means that mass injection equal to mass loss, and energy removal equal to decay heat is achieved. For a spectrum of break sizes appropriate for relatively small LOCAs, conservative analysis assures that no uncovering of the core occurs prior to achieving excess mass injection. Thus, any concerns with very small-break LOCAs deal with the energy balance once excess injection has been achieved.

For certain small breaks, the steam generator would act as an energy removing device. Energy removal occurs through a three-step sequence: initially, a solid flow-forced convection process would control heat removal, later a two-phase natural circulaton process involving both convection and condensation heat transfer would control, and finally a pure condensation mode would result. In this latter mode, fluid has fallen to approximately level B on Figure 6-1. As steam is produced in the core through boiling, it travels through D, F, and G and is condensed in the lower regions of H. Concerns over the impact of noncondensible gases have been examined for this phase and the following points apply:

(1) Insufficient noncondensibles are available in the initial RCS fluid to block the flow of steam at G (this is a 3-ft diameter pipe).

(2) Heat transfer coefficients with noncondensibles present are sufficiently large to condense steam in the lower regions of H. Even if the heat transfer were momentarily inadequate, this would merely cause a pressure increase and resultant temperature increase until the temperature difference compensated for the lower heat transfer coefficient.

(3) The open manometer paths D, F, G, H, and B assure that hydrostatic balances exist between regions H and A, and between regions K and A. If these balances do not exist, fluid movement will occur to produce them.

After excess mass injection is achieved, the RCS starts to refill. During refill, a rising water level in region H may eliminate condensing heat transfer. Note that a rise of level in H also means a rising level in K and A. Thus, no immediate core concern exists. Steam pockets will be formed at J and C. If the level continues to rise, a two-phase mixture will be forced into D and F. This will occur through the necessity of maintaining a hydrostatic balance with H. However, if condensation ceases, the energy balance is no longer maintained. As energy is not being adequately removed from the system, the system must repressurize. Two mechanisms are now possible:

(1) The break flow increases until it removes enough energy, or the break allows removal of enough mass to reestablish condensation, or

(2) Repressurization continues until energy removal is brought about through the pressurizer relief valve path E.

Most likely, mechanism (1) will repeat for several cycles prior to mechanism (2) occurring. In any case, uncovering of the core cannot take place. Again, if the core fluid level is lowered, then the fluid level in H must be low and condensation is a credible phenomenon. The flow pattern in D, the horizontal section of the hot leg, is of interest during repressurization. This is illustrated in Figure 6-2 along with the pressures within the system. The following hierarchy of pressures exists:

$$P_o < P_3 < P_1 < P_2$$

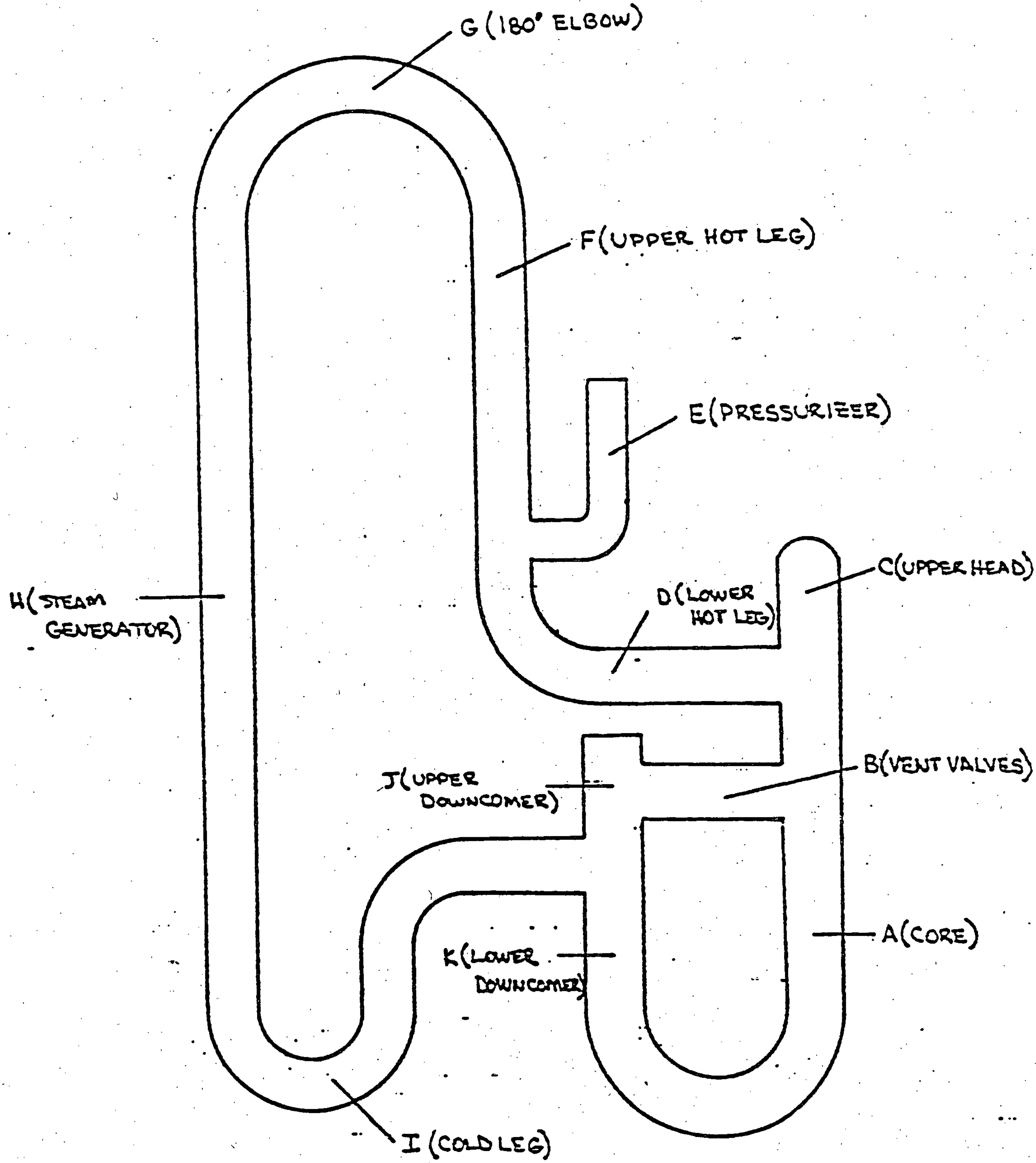


Figure 6-1 B&W System as a Sealed Manometer for a Relatively Small LOCA

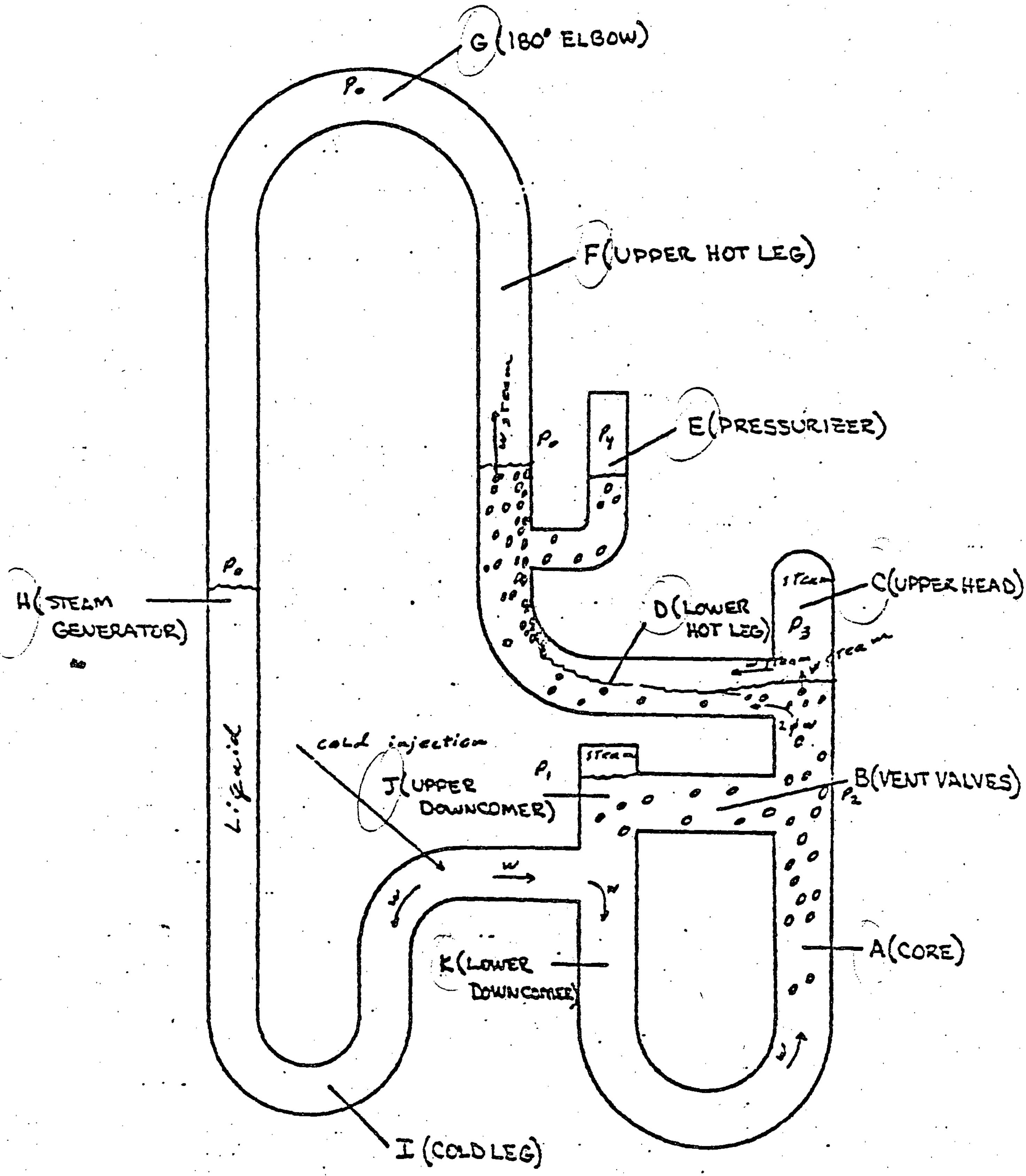


Figure 6-2 Flow Pattern During RCS Repressurization Following a Relatively Small LOCA

QUESTION 26

Considering such matters as (1) off-site power failure, (2) condenser vacuum failure, (3) spurious main feedwater valve closure (see item 21 preceding) and recent incidents of failures in auxiliary feedwater systems it appears that, single failure criteria notwithstanding, at least short term failures of the auxiliary feedwater system must be considered to estimate the needed reliability of such system.

What, for instance, would be the peak primary system pressure, consequences to primary coolant system safety and relief valves and rate of primary coolant loss following failure of the Auxiliary Feedwater pumps when needed?

Response to Question 26

The feedwater systems are designed to current NRC regulations. Since these regulations include criteria for design and analysis assuming one single failure, and the safety-grade Auxiliary Feedwater System contains multiple redundant trains (four 50%-size capacity pumps are installed with independent power sources), the Pebble Springs design complies with the latest requirements. Postulation of an event whereby all feedwater is lost requires multiple failures in the main and auxiliary feedwater systems.

Nonetheless, a preliminary analysis has been made to determine the event sequence, assuming that all feedwater is lost instantaneously without regard for a realistic mechanism. The following is an estimate of the sequence of events expected:

Time	Event
0 sec	All feedwater is lost and the RCS begins to increase in pressure.
~ 7 sec	Reactor trips on high RCS pressure.
~10 sec	Pressurizer begins to relieve decay heat via steam to the RC drain tank at the pressurizer safety valve setpoint of 2500 psig (RCS pressure about 2740 psig).
~ 2 min	Reactor coolant expansion causes the pressurizer to become water solid, and water relief to the RC drain tank begins (RCS pressure about 2500 psig).
<10 min	Containment pressure increases to the ESFAS setpoint (4 psig), and high-pressure ECCS coolant injection to the core starts automatically.
~45 min	High-pressure ECCS injection flow heat removal rate is about equal to the decay heat generation rate. Prior to this time, boiling has occurred in the core; and after this time, it will diminish. A coolable geometry is maintained at all times.
Long term	ECCS high-pressure injection will continue to provide coolant from the borated water storage tank (BWST). When the BWST low-level signal is reached, the operator can switch the ECCS high-pressure coolant injection to the recirculation mode, if auxiliary or main feedwater has not been restored (see Pebble Springs Section 6.3.1.4.1 for a discussion on this mode).

APPENDIX X

IE BULLETINS

(79-5, 79-05A, 79-05B, 79-06, 79-06A,
79-06A Rev. 1, 79-06B, 79-08)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

NUCLEAR INCIDENT AT THREE MILE ISLAND

Description of Circumstances:

On March 28, 1979 the Three Mile Island Nuclear Power Plant, Unit 2 experienced core damage which resulted from a series of events which were initiated by a loss of feedwater transient. Several aspects of the incident may have general applicability in addition to apparent generic applicability at operating Babcock and Wilcox reactors. This bulletin is provided to inform you of the nuclear incident and to request certain actions.

Actions To Be Taken By Licensees:

(Although the specific causes have not been determined for individual sequences in the Three Mile Island event, some of the following may have contributed).

For Babcock and Wilcox pressurized water reactor facilities with an operating license:

1. Review the description (Enclosure 1) of the initiating events and subsequent course of the incident. Also review the evaluation by the NRC staff of a postulated severe feedwater transient related to Babcock and Wilcox PWRs as described in Enclosure 2.

   These reviews should be directed at assessing the adequacy of your reactor systems to safely sustain cooldown transients such as these.

2. Review any transients of a similar nature which have occurred at your facility and determine whether any significant deviations from expected performance occurred. If any significant deviations are found, provide the details and an analysis of the significance and any corrective actions taken. This material may be identified by reference if previously submitted to the NRC.

3. Review the actions required by your operating procedures for coping with transients. The items that should be addressed include:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to ensure continued core cooling in the event that such voids are formed.

4. Review the actions requested by the operating procedures and the training instructions to assure that operators do not override automatic actions of engineered safety features without sufficient cause for doing so.

5. Review all safety related valve positions and positioning requirements to assure that engineered safety features and related equipment such as the auxiliary feedwater system, can perform their intended functions. Also review related procedures, such as those for maintenance and testing, to assure that such valves are returned to their correct positions following necessary manipulations.

6. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the containment to assure that undesired pumping of radioactive liquids and gases will not occur inadvertently.

   In particular assure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists and,

   b. Whether such systems are isolated by the containment isolation signal.

7. Review your prompt reporting procedures for NRC notification to assure very early notification of serious events.

The detailed results of these reviews shall be submitted within ten (10) days of the receipt of this Bulletin.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Construction Inspection, Washington, D.C. 20555.

For all other operating reactors or reactors under construction, this Bulletin is for information purposes and no report is requested.

Approved by GAO, B180225 (R0072); clearance expires 7-31-80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosures:

1. Preliminary Notifications Three Mile Island - PNO-67 and 67A, B, C, D, E, F, G
2. Evaluation of Feedwater Transients w/attachment
3. List of IE Bulletins issued in last 12 months

PRELIMINARY NOTIFICATION

March 28, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67

This preliminary notification constitutes EARLY notice of event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania
(Docket No. 50-320)

Subject: REACTOR SCRAM FOLLOWED BY A SAFETY INJECTION AT THREE MILE ISLAND - UNIT 2

The licensee notified Region I at approximately 7:45 AM of an incident at Three Mile Island Unit 2 (TMI-2) which occurred at approximately 4:00 AM at 98% power when the secondary feed pumps tripped due to a feedwater polishing system problem. This resulted in a turbine trip and subsequent reactor trip on High Reactor Coolant Pressure. A combination of Feed Pump Operation and Pressurizer Relief - Steam Generator relief valve operation caused a Reactor Coolant System (RCS) cooldown. At 1600 psig, Emergency Safeguards Actuation occurred. All ECCS components started and operated properly. Water level increased in the Pressurizer and Safety Injection was secured manually approximately 5 minutes after actuation. It was subsequently resumed. The Reactor Coolant Pumps were secured when low net positive suction head limits were approached.

About 7:00 AM, high activity was noted in the RCS Coolant Sample Lines (approximately 600 mr/hr contact readings). A Site Emergency was then declared. At approximately 7:30 AM, a General Emergency was declared based on High Radiation levels in the Reactor Building. At 8:30 AM site boundary radiation levels were reported to not be significant (less than 1 mr/hr). The source of activity was stated to be failed fuel as a result of the transient, and due to a known previous primary to secondary leak in Steam Generator B.

The Region I Incident Response Center was activated at 8:10 AM and direct communications with the licensee and IE:Headquarters was established. The Response Team was dispatched at 8:45 AM and arrived at the site at 10:05 AM.

At 10:45 AM the Reactor Coolant System Pressure was being held at 1950 psig with temperature at 220°F in the cold leg. By 10:45 AM, radiation levels of 3 mr/hr had been detected 500 yards offsite.

CONTINUED

There is significant media interest at the present time because of concern about potential offsite radiation/contamination. The Commonwealth of Pennsylvania and EPA have been informed. Press contacts are being made by the licensee and NRC.

Contact: GKlingler, IE x28019 FNolan, IE x28019 SEBryan, IE x28019

Distribution: Transmitted H St ~~3:35~~ 3:45

Chairman Hendrie	Commissioner Bradford	S. J. Chilk, SECY
Commissioner Kennedy	Commissioner Ahearne	C. C. Kammerer, CA
Commissioner Gilinsky		(For Distribution)
Transmitted: MNBB 3:50	P. Bldg 3:40	J. G. Davis, IE
L. V. Gossick, EDO	H. R. Denton, NRR	Region I 3:55
H. L. Ornstein, EDO	R. C. DeYoung, NRR	
J. J. Fouchard, PA	R. J. Mattson, NRR	
N. M. Haller, MPA	V. Stello, NRR	(MAIL)
R. G. Ryan, OSP	R. S. Boyd, NRR	J. J. Cummings, OIA
H. K. Shapar, ELD	SS Bldg 3:52	R. Minogue, SD
	W. J. Dircks, NMSS	

PRELIMINARY NOTIFICATION

March 29, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67A

This preliminary notification constitutes EARLY notice of event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND - UNIT 2

This supplements PNO-79-67 dated March 28, 1979.

As of 3:30 p.m., on March 28, 1979, the plant was being slowly cooled down with Reactor Coolant System (RCS) pressure at 450 psi, using normal letdown and makeup flow paths. The bubble has been collapsed in the A Reactor Coolant Loop hot leg, and some natural circulation cooling has been established. Pressurizer level has been decreased to the high range of visible indication, and some heaters are in operation. The secondary plant was being aligned to draw a vacuum in the main condenser and use the A Steam Generator for heat removal. The facility plans to continue a slow (3°F/hr) cooldown, until the Decay Heat Removal System can be placed in operation at 350 psi RCS pressure, 350°F RCS temperature in 15-18 hours.

As of 3:30 p.m., a plume approximately ½ mile wide and reading generally 1 mr/hr was moving to the north of the plant. The ARM's helicopter is being used to define the length of the plume. Airborne iodine levels of up to 1×10^{-8} uCi/ml have been detected in Middletown, Pennsylvania, which is located north of the site.

Media interest is continuing. The Commonwealth of Pennsylvania is being kept informed by plant personnel.

Contact: GKlingler, IE x28019 FNolan, IE x28019 SEBryan, IE x28019

Distribution: Transmitted H St [illegible] 10:30
Chairman Hendrie
Commissioner Kennedy
Commissioner Gilinsky
Commissioner Bradford
Commissioner Ahearne
10:32
S. J. Chilk, SECY
C. C. Kammerer, CA
(For Distribution)

Transmitted: MNBB 10:25
L. V. Gossick, EDO
H. L. Ornstein, EDO
J. J. Fouchard, PA
N. M. Haller, MPA
R. G. Ryan, OSP
H. K. Shapar, ELD

P. Bldg [illegible]
H. R. Denton, NRR
R. C. DeYoung, NRR
R. J. Mattson, NRR
V. Stello, NRR
R. S. Boyd, NRR
SS Bldg 10:28
W. J. Dircks, NMSS

J. G. Davis, IE
Region I 10:33

(MAIL)
J. J. Cummings, OIA
R. Minogue, SD

29 MAR 1979

PRELIMINARY NOTIFICATION

March 30, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67B

This preliminary notification constitutes EARLY notice of event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: Nuclear Incident at Three Mile Island

Plant Status

Three Mile Island Unit 2 is continuing to remove decay heat through A-loop steam generator using one reactor coolant pump in that loop for coolant circulation. The reactor coolant pressure and temperature were stable and under control throughout the night of March 29. There has been some difficulty in maintaining coolant letdown flow due to resistance in the purification filters. The licensee notified IE at about 11:00 p.m. on March 29 that they expected to remain in this cooling mode for at least 24 hours.

The licensee's engineering staff was requested by NRR to obtain a better estimate of the volume of the noncondensible "bubbles" in the reactor coolant system. There are apparently two such bubbles one in the pressurizer that has been intentionally established for control of pressure and level, and one in the reactor vessel head caused by the accumulation of noncondensible gases from failed fuel and radiolytic decomposition of water. The estimate is to be obtained by correlating pressurizer pressure and level indications over the past hours of stable operation. The volume of the bubble in the reactor vessel is of interest in assuring that sufficient volume remains in the upper head for collection of more noncondensible gases arising from continued operation in the present cooling mode as well as to assess the potential for movement of the bubble during a switchover to decay heat removal operation.

The licensee believes it is prudent to remain in the present cooling mode due to the potential for leakage of highly radioactive coolant from the decay heat removal system into the auxiliary building, movement of noncondensible gases into the reactor coolant loop, and boiling in the core when the reactor coolant pump is shut down.

CONTINUED

Fuel Damage

Preliminary assessment of the extent of fuel damage from a reactor coolant sample taken at approximately 5:00 p.m. on March 29 indicates significant releases of iodine and noble gases from the fuel. A 100 milliliter sample taken from the primary coolant system via a letdown line was measured at about 1,000 R/hr on contact (70-80 R/hr at one foot and 10-30 R/hr at three feet). Preliminary analysis of a diluted sample in the IE mobile laboratory indicated fission product concentrations of about 8 x 10^5 microcuries per milliliter. The sample will be flown to Bettis Laboratory for further analysis.

Thermocouple readings of coolant temperature at the outlet of the instrumented fuel assemblies indicate potential local core damage, possibly in one quarter of the total of 177 fuel assemblies and generally in the center of the core. Of the 52 readings at 5:00 a.m. on March 30, one was above the coolant saturation temperature of about 550°F, 7 were above 350°F, and 2 were off-scale, indicating temperatures higher than 700°F. Upon request of NRR, Babcock and Wilcox is developing a procedure for use by the licensee in taking direct potentiometer readings from the off-scale thermocouples since the temperature scale limitation of 700°F is controlled by the process computer, not the thermocouple itself.

Reactor Coolant System (RCS) Parameters

The RCS parameters have remained relatively stable during the period. Gradual RCS cooldown continued to about 1:30 a.m., March 30, when temperature was slightly increased to allow additional margin between RCS operating parameters and Technical Specification minimum pressurization limits. Following are the primary system parameters over this period:

	10:00 a.m. 3/29/79	7:00 p.m. 3/29/79	12:01 a.m. 3/30/79	3:00 a.m. 3/30/79	5:00a.m. 3/30/79
Pressurizer Level (inches)	348	321	326	342	354
Pressurizer Pressure (psi)	863	945	1023	1055	1053
Pressurizer Temperature (°F)	529	542	551	556	557
Loop A Core Inlet Temperature (°F)	281	277	275	278	274
Loop B Core Inlet Temperature (°F)	281	277	275	278	274

CONTINUED

Environmental Status

Two aerial surveys were conducted during the evening of March 29. The first flight was made about 8:15 p.m. during which measurements were taken in a circle around the site with a radius of about eight miles. No defined plume of radioactivity was detected, but residual pockets of radioactivity were identified at various points where the measured levels ranged from .025 to .050 milliroentgens per hours. (Natural background levels are about .005 to .015 milliroentgens per hour.) During the second flight, at about 10:30 p.m., a plume was detected northwest of the plant with a width equal to and confined within the boundaries of the river. The plume was touching down about one mile from the plant at Hill Island and then splitting into two parts - one on each side of Hill Island. Measurements at the east shoreline of the river, opposite Hill Isalnd indicated about four milliroentgens per hour and at the shoreline on mile north of Hill Island near Olmstead Air Force Base about one milliroentgen per hour. Additional measurements at five miles from the plant were on the order of .010 milliroentgens per hour and are in agreement with the earlier flight.

During the early morning hours of March 30, an NRC monitoring team took radiation measurements from a vehicle traveling both sides of the Susquehanna River from 10 miles south of Three Mile Island to 4 miles north. Radiation levels were highest near Cly, a community just south of the facility on the west side of the river. The level at Cly was 0.15 milliroentgen per hour. All other locations had levels less than 0.05 milliroentgens per hour.

Other Information

At approximately 4:00 p.m. on March 29, two employees of Metropolitan Edison Co. received radiation exposures in excess of the quarterly limit of 3 rems. The employees, an operator and a chemist, entered the auxiliary building to collect a sample of primary coolant. Present estimates are that the operator received 3.1 rems and the chemist 3.4 rems.

The licensee released less than 50,000 gallons of slightly contaminated industrial wastes on March 29, 1979. This release was terminated at NRC request at approximately 6:00 p.m., March 29, 1979, because of concerns expressed by state representatives. At about 12:15 a.m. on March 30, NRC gave the licensee permission to resume releases of the slightly contaminated industrial wastes to the Susquehanna River. This action was coordinated with the office of the Governor of Pennsylvania and a press rlease was issued by the State. Representatives of the news media expressed concern that they were not informed of the planned resumption of the release prior to permission having been granted.

CONTINUED

At 8:40 a.m., on March 30 the licensee began venting from the gaseous waste tanks. The impact of this operation is not yet known.

Contact: DThompson, IE x28111; EJordan, IE x 28111

Distribution: Transmitted H St 9:50
Chairman Hendrie
Commissioner Kennedy
Commissioner Gilinsky
Commissioner Bradford
Commissioner Ahearne
S. J. Chilk, SECY
C. C. Kammerer, CA
(For Distribution)

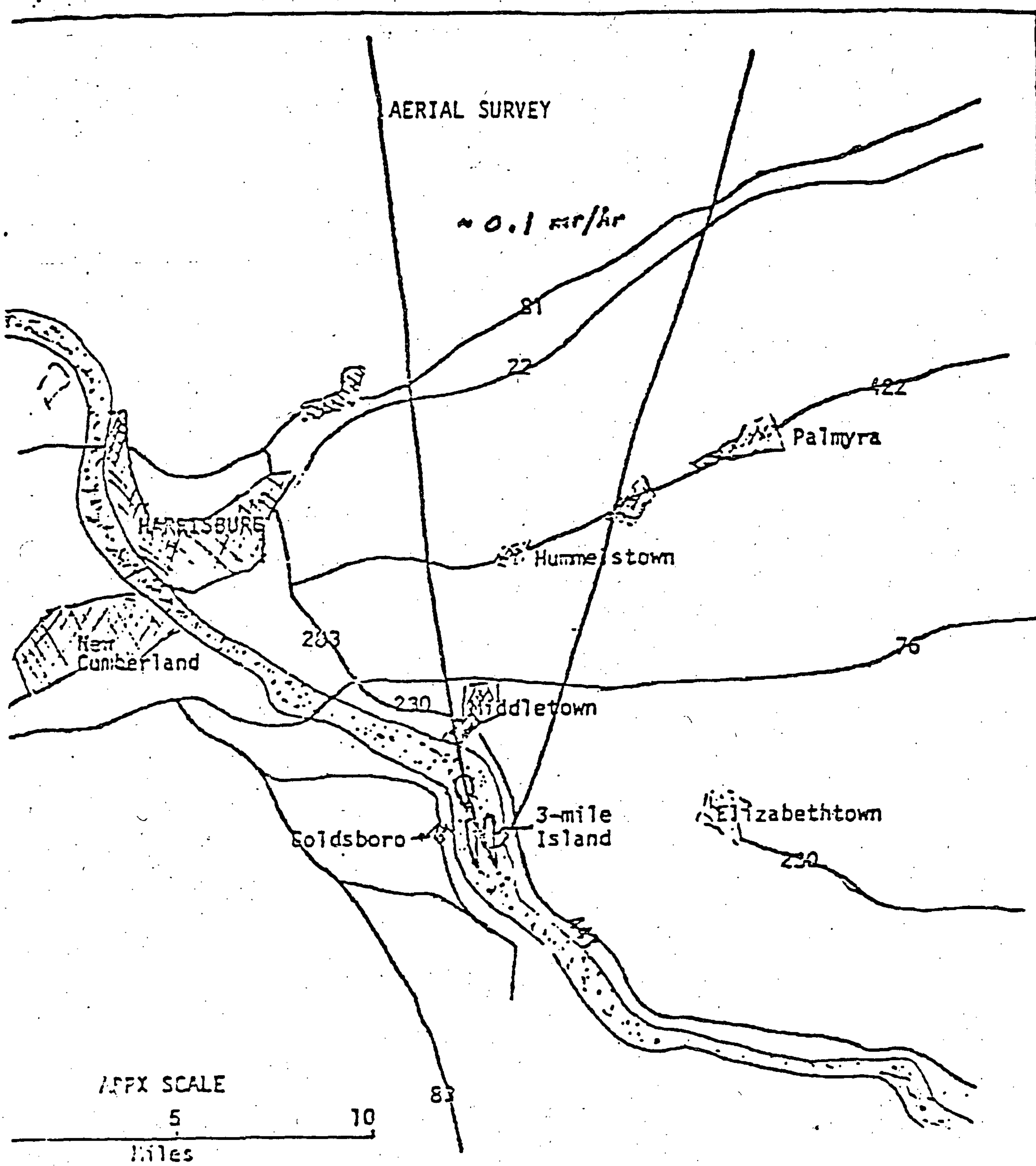
Transmitted: MNBB 10:02
L. V. Gossick, EDO
H. L. Ornstein, EDO
J. J. Fouchard, PA
N. M. Haller, MPA
R. G. Ryan, OSP
H. K. Shapar, ELD

P Bldg 10:15
H. R. Denton, NRR
R. C. DeYoung, NRR
R. J. Mattson, NRR
V. Stello, NRR
R. S. Boyd, NRR
(SS Bldg ______
W. J. Dircks, NMSS

J. G. Davis, IE
Region ____ _____

(MAIL)
J. J. Cummings, OIA
R. Minogue, SD

Attachments (7):
Aerial Survey (6)
Ground-Level Survey (1)



2?, 1979   4:30 p.m.

Plume in a N to NE direction, about 30° sector.
Primarily Xe-133. At distance of about 16 miles,
radiation measurements in the plume were about 0.1 mr/hr.

March 30, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67C

This preliminary notification constitutes EARLY notice of event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-520)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND

Plant Status

There have been intermittent uncontrolled releases of radioactivity into the atmosphere from the primary coolant system of Unit 2 of the Three Mile Island Nuclear Power Plant near Harrisburg, Pennsylvania. The licensee is attempting to stop the intermittent gaseous releases by transferring the radioactive coolant water into the primary containment building. The levels of radioactivity being measured have been as high as 20 to 25 millirem per hour in the immediate vicinity of the site at ground level. Off-site levels were a few milliroentgen.

At about 11:30 a.m. EST, the Chairman of the NRC has suggested to Governor Thornburg of the Commonwealth of Pennsylvania that pregnant women and pre-school children in an area within five miles of the plant site be evacuated. Members of the NRC technical staff are at the site and efforts to reduce the temperatures of the reactor fuel are continuing. These temperatures have been coming down slowly and the final depressurization of the reactor vessel has been delayed. There is evidence of severe damage to the nuclear fuel. Samples of primary coolant containing high-levels of radioiodine and instruments in the core indicate high fuel temperatures in some of the fuel bundles, and the presence of a large bubble of non-condensible gases in the top of the reactor vessel.

Because of these non-condensible gases, the possiblity exists of interrupting coolant flow within the reactor when its pressure is further decreased and the contained gases expand. Several options to reach a final safe state for the fuel are under consideration. In the meantime, the reactor is being maintained in a stable condition.

Contact: SEBryan, IE x28188 ELJordan, IE x28188

Distribution: Transmitted H St 4:15

Chairman Hendrie
Commissioner Kennedy
Commissioner Gilinsky

Commissioner Bradford
Commissioner Ahearne

S. J. Chilk, SECY
C. C. Kammerer, CA
(For Distribution)

Transmitted: MNBB ____
L. V. Gossick, EDO
H. L. Ornstein, EDO
J. J. Fouchard, PA
N. M. Haller, MPA
R. G. Ryan, OSP
H. K. Shapar, ELD

P. Bldg 4:17
H. R. Denton, NRR
R. C. DeYoung, NRR
R. J. Mattson, NRR
V. Stello, NRR
R. S. Boyd, NRR
SS Bldg ____
W. J. Dircks, NMSS

J. G. Davis, IE
Region I 4:30

(MAIL)
J. J. Cummings, OIA
R. Minogue, SD

IMMEDIATE

PRELIMINARY NOTIFICATION

March 30, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67D

This preliminary notification constitutes EARLY notice of an event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND

Plant Status

Gaseous radioactivity from the primary coolant system letdown has been contained in waste gas decay tanks since the last gaseous release at approximately 2:50 p.m. March 30, 1979. At the present reactor coolant letdown rate of approximately 20 gpm it may be necessary to make a planned release of radioactive gas tomorrow to prevent gas decay tank relief valve operation at its setpoint of 100 psi. The licensee has installed a temporary line from the gas decay system back to reactor containment which is under evaluation before being placed in operation. Containment pressure is being maintained slightly negative (-1 psi) as a result of fan cooler operation.

Reactor coolant temperature measured at fifty-two locations at the outlet of the core have continued to come down slowly. Three Outlet temperature instruments continue to indicate above saturation temperature.

The NRC staff was informed by the licensee on Friday morning that examination of containment pressure data for March 28 indicates a pressure spike up to approximately 30 psi occurred at approximately 1:50 p.m. NRC personnel are evaluating the possibility that a hydrogen explosion was the cause of the containment internal pressure spike.

The reactor coolant path is through one reactor coolant pump and one steam generator. The steam generator is being fed by an auxiliary feed-pump. Several options for depressurizing the reactor and continuing cooldown via the residual heat removal system are under consideration.

CONTINUED

The volume of non-condensible gases in the reactor vessel has been estimated to be approximately 1000 to 1500 cubic feet at 1000 psi. This volume is estimated to result in a water level of several feet over the top of the fuel. The rate of growth of the bubble in the reactor vessel is estimated to be less than 50 cubic feet per day at 1000 psi.

The Director of the Office of Nuclear Reactor Regulation, the Director of the Region I Office of Inspection and Enforcement and the Director of the Division of Operating Reactors arrived at the site at approximately 2 p.m. today to direct NRC activities at the site and site vicinity. Representatives of HEW and EPA are providing coordination and assistance to the NRC at the Incident Response Center.

NRC personnel assembled at the TMI site and vicinity in addition to the upper management personnel consist of the following:

	RI	RII	RIII	Hq
Reactor Inspectors (IE)	8	5	4	
Health Physicists (IE)	12	12	10	
Health Physicists (SP)				4
Public Affairs	1	1		1
Reactor System Analysts (NRR)				13
Radition Waste Specialists (NRR)				4
Health Physicists (NRR)				6
Operating Licensing (NRR)				2
Total Staff			83	

CONTINUED

The following equipment has been assembled at or near the site for support of NRC operations:

Equipment	Location
1 NRC Instrument Van with 2 telephone lines	Observation Center
1 NRC Office Van	"
1 Office Trailer (Supplied by Licensee)	"
200 Hand-Held Portable Radios from US Forest Service	
Portable Health Physics Instrumentation	
3 Helicopters from DOE for survey and support	
2 Laboratory Vans DOE/Bettis	

A sophisticated communications pod from DOE/NEST will arrive tomorrow.

ENVIRONMENTAL STATUS:
At approximately 3 P.M. on March 30, 1979, NRC analysis of eight vegetation samples from the offsite areas showed no detectable activity. At 5.30 P.M. the Pennsylvania State Radiation Health Department reported that environmental water and air samples collected in the vicinity of the Three Mile Island Plant showed no detectable activity except for some Xenon-133 and Xenon-135. Milk sample analysis showed no activity levels above background.

Offsite ground level gamma surveys in the Middletown and Goldsboro areas between 3:00 and 6:00 P.M. on March 30, ranged from .01 to 1 milliroentgens per hour. An aerial survey was made by helicopter from 4:00 - 6:00 P.M. on March 30, the site was surveyed in concentric circles at approximately one mile intervals and at a height of 300 to 1,000 feet. The highest radiation readings were over the site and measured 8 to 10 milliroentgens per hour. In the plume the highest radiation readings were 6 to 8 milliroentgens per hour. The plume followed the river in a northwesterly direction and was not detectable beyond five to six miles from the site. Site ground level surveys conducted between 7:30 - 8:00 P.M. ranged from .01 to 1.8 milliroentgens per hour.

CONTINUED

At 4 P.M. March 30, upper level winds were from the southeast. Forecast indicates precipitation in the form of thunderstorms moving in after 12 midnight, March 30. At 5:00 P.M. winds onsite at Three Mile Island were reported at 2 to 3 miles per hour generally from east to west.

Contact: EMHoward, IE x28111; EJordan, IE x28111

Distribution: Transmitted H St 1:10 a 3/31

Chairman Hendrie	Commissioner Bradford	S. J. Chilk, SECY
Commissioner Kennedy	Commissioner Ahearne	C. C. Kammerer, CA
Commissioner Gilinsky		(For Distribution)

Transmitted: MNBS 1:17	P Bldg 1:25	J. G. Davis, IE
L. V. Gossick, EDO	H. R. Denton, NRR	Region ____ ____
H. L. Ornstein, EDO	R. C. DeYoung, NRR	
J. J. Fouchard, PA	R. J. Mattson, NRR	
N. M. Haller, MPA	V. Stello, NRR	(MAIL)
R. G. Ryan, OSP	R. S. Boyd, NRR	J. J. Cummings, OIA
H. K. Shapar, ELD	(SS Bldg 1:33	R. Minogue, SD
	W. J. Dircks, NMSS	

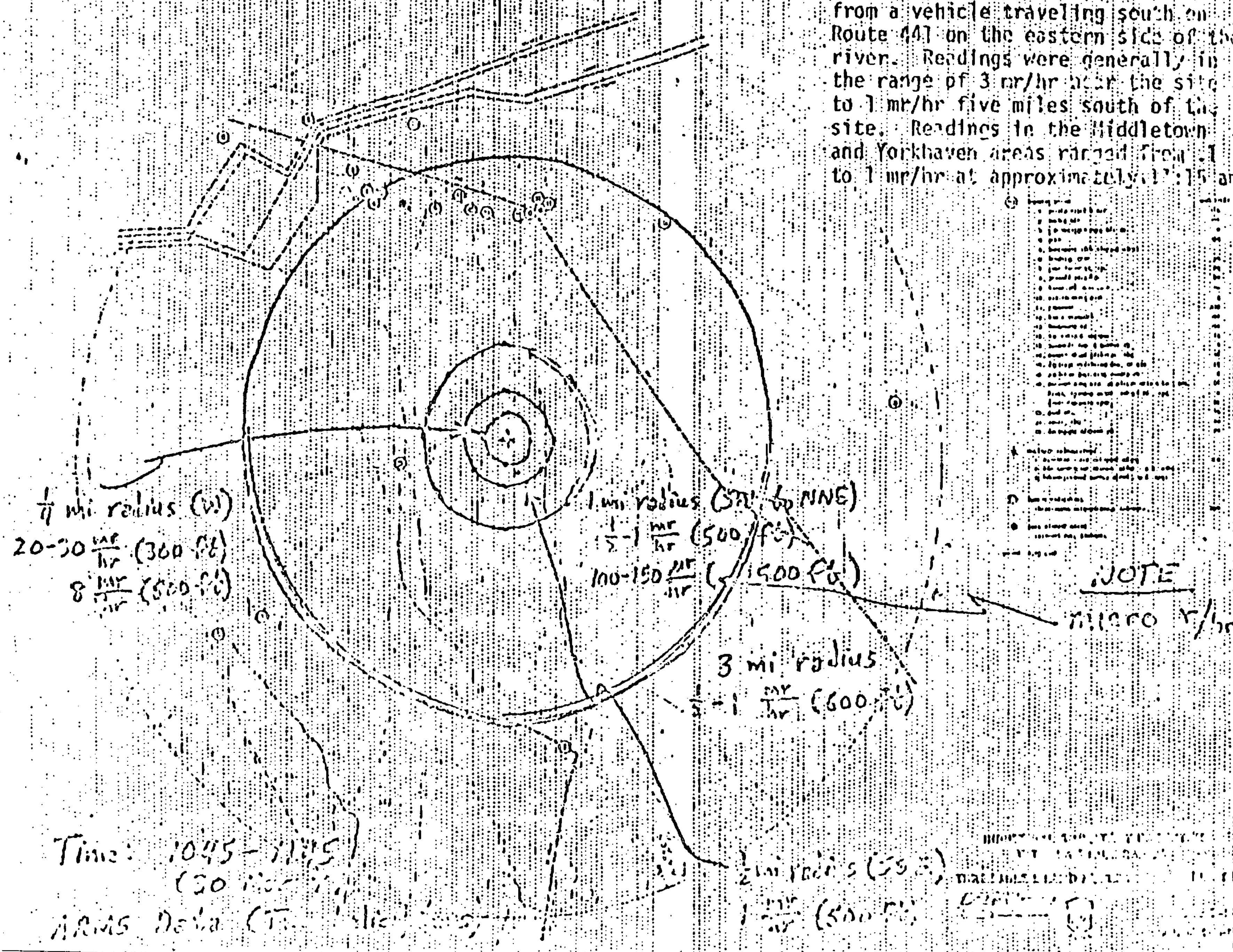
White House Situation Room 12:55 a.m. 3/31/79
EPA ____________
FDA/BRH ____________
DOE/EOC 2:00 am 3/31

Attachment (1)
Radiation Survey Map

IMMEDIATE

PRELIMINARY NOTIFICATION

At approximately 10:30 am, an NRC survey team took survey measurements from a vehicle traveling south on Route 441 on the eastern side of the river. Readings were generally in the range of 3 mr/hr near the site to 1 mr/hr five miles south of the site. Readings in the Middletown and Yorkhaven areas ranged from .1 to 1 mr/hr at approximately 11:15 am.



IMMEDIATE

PRELIMINARY NOTIFICATION

March 31, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67E

This immediate preliminary notification constitutes an update of event of safety and public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by NRC staff at this time.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND

Plant Status

Reactor cooling continues using the 1A main reactor coolant pump with steam generator A steaming to the main condenser. Changes to this cooling method are not planned for the near term. An operability status of equipment is being compiled for use as backup in the event of failure of existing operating equipment.

The hydrogen recombiner is in an operable status; however, shielding of its piping and components is not fully installed and is presently considered inadequate. Lead for shielding has been located and will be moved to the site on an expedited basis. Calculations of hydrogen in containment show that the present concentration is less than 4%, the staff's limit on allowed concentration to ensure an explosive mixture is not obtained. Attempts are being made to obtain a containment atmosphere sample.

The waste gas decay tank pressures were 80 psi at 10:15 p.m. on March 30 and had been relatively constant for about five hours. The tank is set to relieve pressure at 100 - 110 psi. The radiation field (60 R/hr at contact) prevents resetting relief points.

Reactor coolant temperatures measured by incore thermocouples at 52 locations presently show only one location above saturation temperature. Temperatures in the core as measured from outlet thermocouples are gradually decreasing. Other system parameters are remaining stable.

Environmental Status

Three ARMS flights of one-hour length were conducted beginning at 9:30 p.m. on March 30, and at midnight and 3:00 a.m. on March 31. At a

CONTINUED

distance of one mile from the plant, maximum readings ranged from 0.5 milliroentgens per hour (mr/hr) to 1.5 mr/hr. At the 18 mile point, readings of 0.1 to 0.2 mr/hr were obtained during the two earlier surveys and 0.5 mr/hr during the latest. Flights are being made at approximately three hour intervals.

Offsite ground level gamma surveys in the Middletown area and north, between 9:30 p.m. on March 30 and 1:00 a.m. on March 31, indicated levels from 0.2 to 0.5 mr/hr. These measurements were taken in the general direction of the plume measured in aerial surveys.

At 3:00 p.m. on March 29, (prior to the releases of March 30) the licensee pulled thermoluminescent dosimeters from 17 fixed positions located within a 15 mile radius of the site. The dosimeters had been in place for three months and had been exposed for about 32 hours after the incident. Only two dosimeters showed elevated exposures above normal levels. The highest reading observed was on Three Mile Island, 0.4 miles north of the reactor at the North Weather Station. At this location, the quarterly accumulated exposure was 81 mr, approximately 65 mr above the normal quarterly exposure rate. The other high exposure was observed at North Bridge, 0.7 miles NNE of the reactor at the entrance to the site. At this location, the total quarterly accumulated exposure was 37 mr or approximately 22 mr above the normal quarterly exposure rate.

During the evening milking hours on March 30, milk samples were collected by the Pennsylvania Department of Environmental Resources at the following locations:

Harrisburg (2 sites)
York
Middletown
Bainbridge
Etters

Analyses showed no detectable radioiodine. The cows had been fed on stored feed but had been outside for exericse.

The Pennsylvania Department of Environmental Resources also collected water samples at filtration plants at Columbia, PA (for the City of Lancaster) and Wrightsville on March 30 in the morning and early afternoon. Both sample points are downstream of Three Mile Island. No detectable activity was found.

CONTINUED

Contact: DThompson, IE x28111 NCMoseley, IE x28111

Distribution: Transmitted H St 9:04

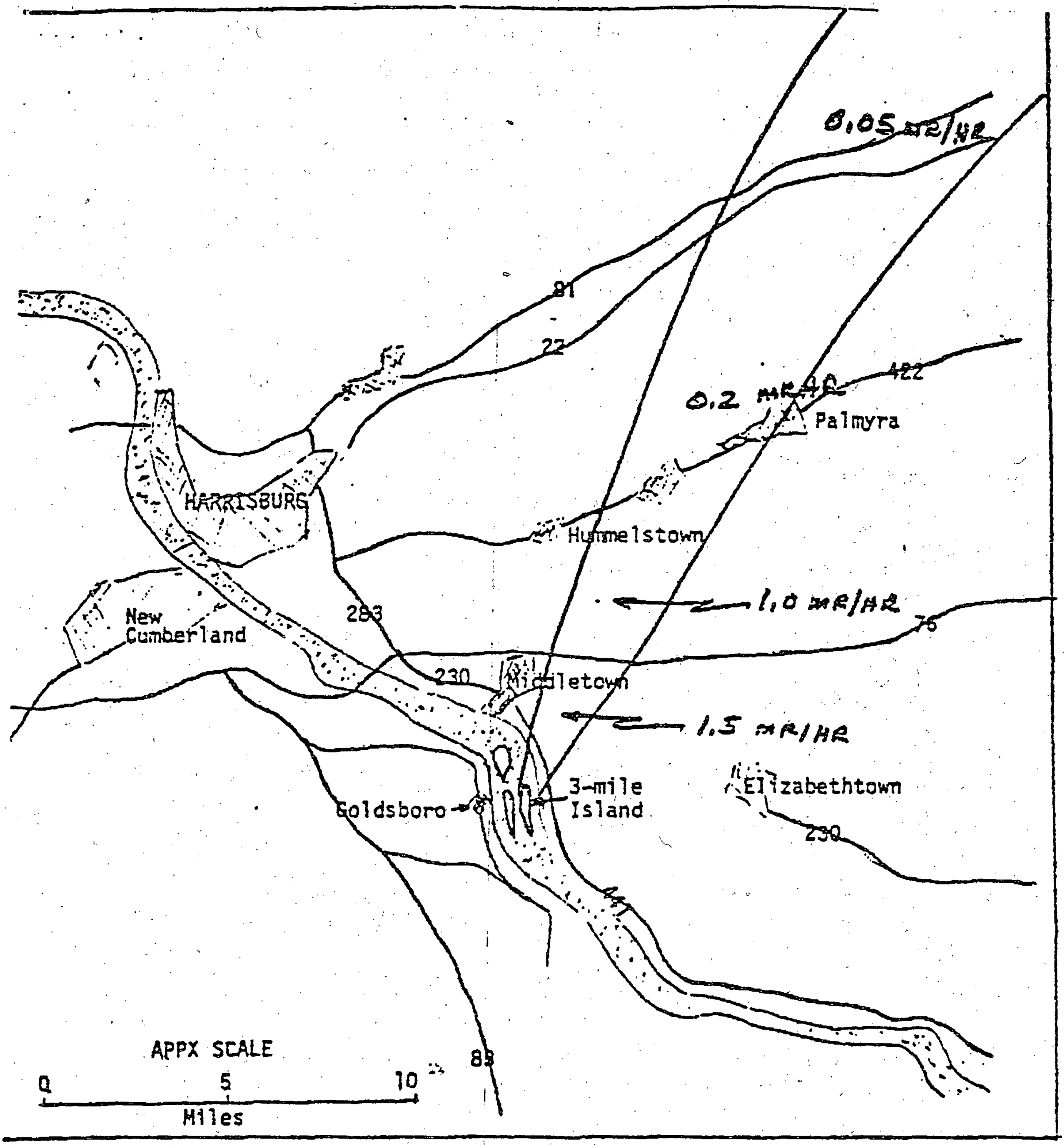
Chairman Hendrie	Commissioner Bradford	S. J. Chilk, SECY
Commissioner Kennedy	Commissioner Ahearne	C. C. Kammerer, CA
Commissioner Gilinsky		(For Distribution)
Transmitted: MNBB 9:08	P. Bldg 9:15	J. G. Davis, IE
L. V. Gossick, EDO	H. R. Denton, NRR	Region I 9:24
H. L. Ornstein, EDO	R. C. DeYoung, NRR	
J. J. Fouchard, PA	R. J. Mattson, NRR	
N. M. Haller, MPA	V. Stello, NRR	(MAIL)
R. G. Ryan, OSP	R. S. Boyd, NRR	J. J. Cummings, OIA
H. K. Shapar, ELD	SS Bldg 9:20	R. Minogue, SD
	W. J. Dircks, NMSS	

White House Situation Room ________
EPA ______
FDA/BRH ______
DOE/EOC ______

Attachment (1)
Radiation Survey Map

IMMEDIATE

PRELIMINARY NOTIFICATION



March 31, 1979 4:00 a.m. AERIAL SURVEY plume direction and radiation readings shown above.

March 31, 1979 1:00 a.m. All ground level readings were less than 0.1 mr/hr. measurements made in vehicle travelling route 441 from about ten miles south of plant to route 76 and south along roads on the west side of the river.

IMMEDIATE

PRELIMINARY NOTIFICATION

March 31, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67F

This preliminary notification constitutes summary information of an event of safety or public interest significance. The information presented is a summary of information as of 5:30 pm date 3/31/79.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND

Plant Status

There has been no change in the method of cooling the reactor since the previous report (PNO-79-67E). Reactor coolant temperatures measured by incore thermocouples at 52 locations have continued to decrease. At present none of the temperature readings is above saturation temperature for this pressure (554°F). System parameters remain stable. There has been a slight drop in pressurizer level from 215 to 191 inches.

Efforts continue to complete installation of components and piping on the hydrogen recombiner. Approximately 220 tons of lead shielding in various shapes and forms has arrived, or is on the way, to the site. Lead shielding is being installed around the recombiner. A decision to use the recombiner has not yet been made. Two samples of containment atmosphere have been analyzed which show hydrogen concentrations of 1.7 and 1.0%.

Efforts continue to estimate the volume of the noncondensible gas bubble above the core. Licensee calculations of the size of the bubble at 2:40 pm was 8[illegible]0 cubic feet at 875 psig. At about 4:20 pm this was recalculated by t licensee to be 621 cubic feet at 875 psig. This is being further evaluated.

Environmental Status

Three ARMS flights were conducted at about 6:00 a.m., 9:00 a.m., and 12:00 noon on March 31. All flights reflected a rather stable situation. Maximum readings in the plume were from 1.5 to 2.5 milliroentgens per hour (mr/hr) at a distance of one mile from the plant, from 0.5 to 1.0 mr/hr out to 7 miles, and 0.1 to 0.2 mr/hr beyond 10 miles. The plume width is about 1-1/2 to 2 miles. No radioiodines have been detected in the plume. Offsite ground level gamma surveys performed in the predominant wind direction indicated maximum levels of about 2 mr/hr at about 1/2 mile from the site in the direction of the plume. The wind was from the SSW at the time of the

CONTINUED

ARMS flights. At about 1 PM the winds shifted and are now blowing in a south easterly direction.

International Contacts

NRC's Office of International Programs (OIP) has prepared daily status reports, transmitted by Immediate Department of State telegrams to official NRC contacts in the 25 foreign countries with which NRC has regular official relations. OIP is also receiving many foreign telephone calls.

Two senior safety experts from the Federal Republic of Germany (FRG) arrived late March 30 and were briefed by NRC experts at the Operations Center, late March 30 and during March 31. Two French experts will arrive April 1. Washington Representatives or senior visitors of Japan, FRG, and Sweden also have been briefed in the Operations Center. OIP also has been briefing the President of the AECB of Canada, who offered to send any AECL or AECB experts who could be of assistance.

Contact with Licensee

NRC Regional Offices are transmitting to the utilities with operating licenses summary information (in the form of Preliminary Notifications) as they are prepared.

Contact: DThompson, IE x28111 EMHoward, IE x28111

Distribution: Transmitted H St 7:06p.

Chairman Hendrie	Commissioner Bradford	S. J. Chilk, SECY
Commissioner Kennedy	Commissioner Ahearne	C. C. Kammerer, CA
Commissioner Gilinsky		(For Distribution)

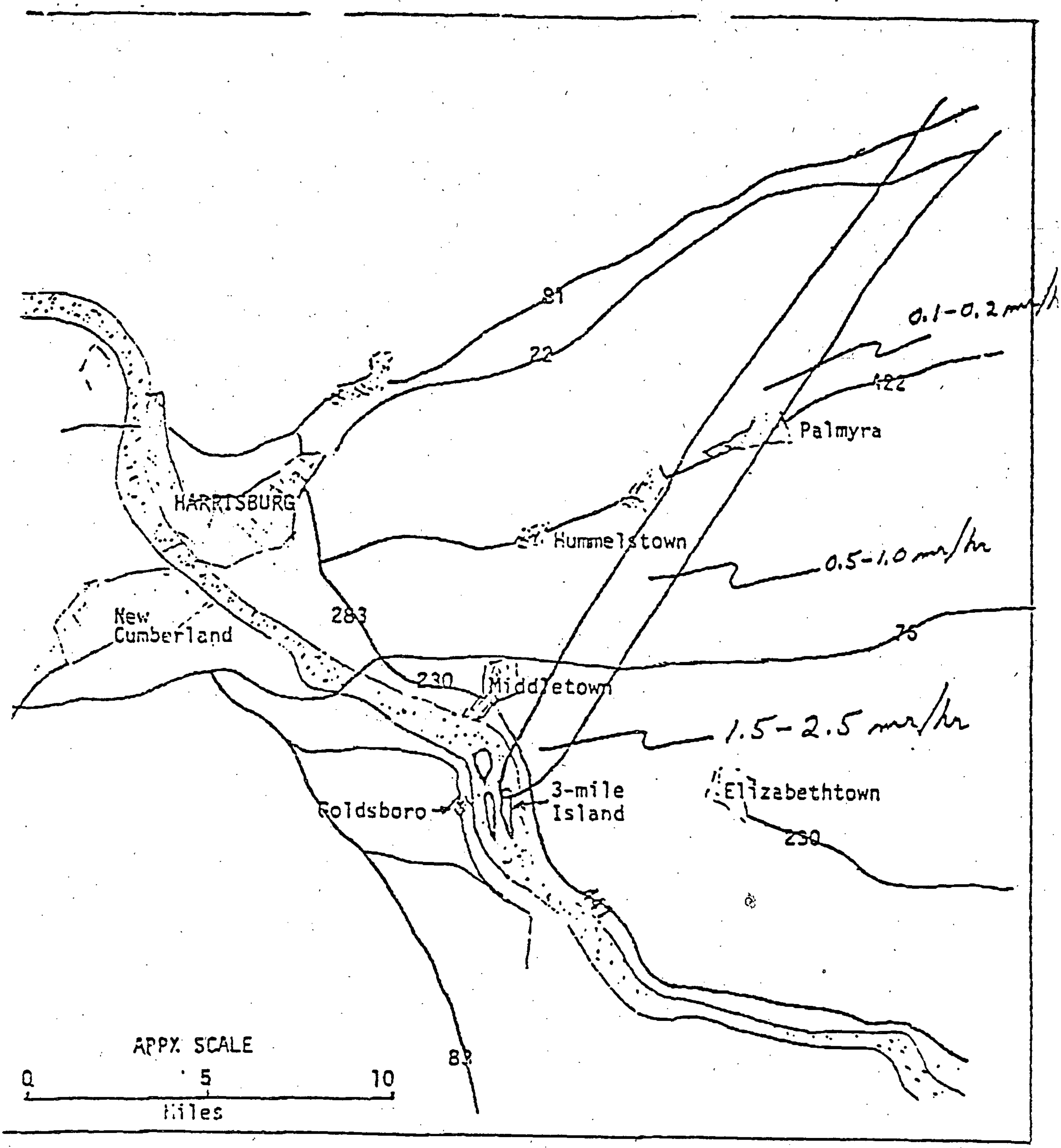
Transmitted: MNBB 7:10p	P. Bldg 7:15p	J. G. Davis, IE
L. V. Gossick, EDO	H. R. Denton, NRR	Region I - 9:00
H. L. Ornstein, EDO	R. C. DeYoung, NRR	Region II
J. J. Fouchard, PA	R. J. Mattson, NRR	Region III
N. M. Haller, MPA	V. Stello, NRR	Region IV
R. G. Ryan, OSP	R. S. Boyd, NRR	Region V - 7:05
H. K. Shapar, ELD	SS Bldg 7:20p	(MAIL)
	W. J. Dircks, NMSS	J. J. Cummings, OIA
		R. Minogue, SD

White House Situation Room 7:25p
EPA
FDA/
DOE/EOC

Attachment (1)
Radiation Survey Map

IMMEDIATE

PRELIMINARY NOTIFICATION



March 31, 1979

AERIAL SURVEY plume direction and radiation readings shown above conducted at 6:00 & 9:00 AM and 12:00 noon.

EVALUATION OF FEEDWATER TRANSIENT

A loss of offsite power occurred at Davis-Besse on November 29, 1977, which resulted in shrinkage of the primary coolant volume to the degree that pressurizer level indication was lost. A recommendation to convey this information to certain hearing boards resulted in the attached discussion and evaluation of the event. This discussion includes a review of a loss of feedwater safety analysis assuming forced flow, which predicts dispersed primary system voiding, but no loss of core cooling. During the Three Mile Island event, however, the forced flow appears to have been terminated during the transient.

Attachment:
Discussion and Evaluation of
Davis-Besse Transients

EXCERPT FROM MEMORANDUM ENTITLED "CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2", DATED JANUARY 8, 1979, FROM J.S. CRESWELL TO J.F. STREETER.

3. Inspection and Enforcement Report 50-346/78-06 documented that pressurizer level had gone offscale for approximately five minutes during the November 29, 1977 loss of offsite power event. There are some indications that other B&W plants may have problems maintaining pressurizer level indications during transients. In addition, under certain conditions such as loss of feedwater at 100% power with the reactor coolant pumps running the pressurizer may void completely. A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1. Because of pressurizer level maintenance problems the sizing of the pressurizer may require further review.

   Also noted during the event was the fact that Tcold went offscale (less than 520°F). In addition, it was noted that the makeup flow monitoring is limited to less than 160 gpm and that makeup flow may be substantially greater than this value. This information should be examined in light of the requirements of GDC 13.

DISCUSSION AND EVALUATION

The event at Davis Besse which resulted in loss of pressurizer level indication has been reviewed by NRR and the conclusion was reached that no unreviewed safety question existed.

The pressurizer, together with the reactor coolant makeup system, is designed to maintain the primary system pressure and water level within their operational limits only during normal operating conditions. Cooldown transients, such as loss of offsite power and loss of feedwater, sometimes result in primary pressure and volume changes that are beyond the ability of this system to control. The analyses of and experience with such transients show, however, that they can be sustained without compromising the safety of the reactor. The principal concern caused by such transients is that they might cause voiding in the primary coolant system that would lead to loss of ability to adequately cool the reactor core. The safety evaluation of the loss of offsite power transient shows that, though level indication is lost, some water remains in the pressurizer and the pressure does not decrease below about 1600 psi. In order for voiding to occur, the pressure must decrease below the saturation pressure corresponding to the system temperature. 1600 psi is the saturation pressure corresponding to 605°F, which is also the maximum allowable core outlet temperature. Voiding in the primary system (excepting the pressurizer) is precluded in this case, since pressure does not decrease to saturation.

The safety analysis for more severe cooldown transients, such as the loss of feedwater event, indicates that the water volume could decrease to less than the system volume exclusive of the pressurizer. During such an event, the emptying of the pressurizer would be followed by a pressure reduction below the saturation point and the formation of small voids throughout much of the primary system. This would not result in the loss of core cooling because the voids would be dispersed over a large volume and forced flow would prevent them from coalescing sufficiently to prevent core cooling. The high pressure coolant injection pumps are started automatically when the primary pressure decreases below 1600 psi. Therefore, any pressure reduction which is sufficient to allow voiding will also result in water injection which will rapidly restore the primary water to normal levels.

For these reasons, we believe that the inability of the pressurizer and normal coolant makeup system to control some transients does not provide a basis for requiring more capacity in these systems.

General Design Criterion 13 of Appendix A to 10 CFR 50 requires instrumentation to monitor variables over their anticipated ranges for "anticipated operational occurrences". Such occurrances are specifically defined to include loss of all offsite power. The fact that T cold goes off scale at 520°F is not considered to be a deviation from this requirement because this indicator is backed up by wide range temperature indication that extends to a low limit of 50°F. Neither do we consider the makeup flow monitoring to deviate since the amount of makeup flow in excess of 160 gpm does not appear to be a significant factor in the course of these occurrences.

The loss of pressurizer water level indication could be considered to deviate from GDC 13, because this level indication provides the principal means of determining the primary coolant inventory. However, provision of a level indication that would cover all anticipated occurrences may not be practical. As discussed above, the loss of feedwater event can lead to a momentary condition wherein no meaningful level exists, because the entire primary system contains a steam water mixture.

It should be noted that the introduction to Appendix A (last paragraph) recognizes that fulfillment of some of the criteria may not always be appropriate. This introduction also states that departures from the Criteria must be identified and justified. The discussion of GDC 13 in the Davis Besse FSAR lists the water level instrumentation, but does not mention the possibility of loss of water level indication during transients. This apparent omission in the safety analysis will be subjected to further review.

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism - General Electric Model CR105X	4/14/78	All Power Reactor Facilities with an Operating License (OL) or Construction Permit (CP)
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority I Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power, Test and Research Reactor Facilities with an OL having Fuel Element Transfer Tubes
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/78	All BWR Power Reactor Facilities with an OL (for action) or CP (for information)
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/24/78	BWR Power Reactor Facilities with an OL for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee. All other BWR Power Reactor Facilities with an OL for information
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All General and Specific Licensees with the subject Kay-Ray, Inc. Gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR Facilities with an OL (for action), and all other Power Reactor Facilities with an OL or CP (for information)

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL, except the 11 Systematic Evaluation Program Plants (for action), and all other Power Reactor Facilities with an OL or CP (for information)
79-02	Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts	3/8/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured by Youngstown Welding and Engineering Company	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP

ENCLOSURE 2

LIST OF LICENSEES AND CONSTRUCTION PERMIT HOLDERS
RECEIVING IE BULLETIN 79-05 FOR INFORMATION

Baltimore Gas and Electric Company ATTN: Mr. A. E. Lundvall, Jr. Vice President - Supply P. O. Box 1475 Baltimore, Maryland 21203	Docket Nos. 50-317 50-318
Boston Edison Company M/C Nuclear ATTN: Mr. G. Carl Andognini, Manager Nuclear Operations Department 800 Boylston Street Boston, Massachusetts 02199	Docket No. 50-293
Connecticut Yankee Atomic Power Company ATTN: Mr. W. G. Counsil Vice President - Nuclear Engineering and Operations P. O. Box 270 Hartford, Connecticut 06101	Docket No. 50-213
Consolidated Edison Company of New York, Inc. ATTN: Mr. W. J. Cahill, Jr. Vice President 4 Irving Place New York, New York 10003	Docket Nos. 50-03 50-247
Duquesne Light Company ATTN: Mr. C. N. Dunn Vice President Operations Division 435 Sixth Avenue Pittsburgh, Pennsylvania 15219	Docket No. 50-334
Jersey Central Power and Light Company ATTN: Mr. Ivan R. Finfrock, Jr. Vice President Madison Avenue at Punch Bowl Road Morristown, New Jersey 07960	Docket No. 50-219

Maine Yankee Atomic Power Company ATTN: Mr. Robert H. Groce Licensing Engineer 20 Turnpike Road Westborough, Massachusetts 01581	Docket No. 50-309
Niagara Mohawk Power Corporation ATTN: Mr. R. R. Schneider Vice President Electric Operations 300 Erie Boulevard West Syracuse, New York 13202	Docket No. 50-220
Northeast Nuclear Energy Company ATTN: Mr. W. G. Counsil Vice President - Nuclear Engineering and Operations P. O. Box 270 Hartford, Connecticut 06101	Docket Nos. 50-336 50-245 50-423
Philadelphia Electric Company ATTN: Mr. S. L. Daltroff Vice President Electric Production 2301 Market Street Philadelphia, Pennsylvania 19101	Docket Nos. 50-277 50-278
Power Authority of the State of New York Indian Point 3 Nuclear Power Plant ATTN: Mr. J. P. Bayne Resident Manager P. O. Box 215 Buchanan, New York 10511	Docket No. 50-286
Power Authority of the State of New York James A. FitzPatrick Nuclear Power Plant ATTN: Mr. J. D. Leonard, Jr. Resident Manager P. O. Box 41 Lycoming, New York 13093	Docket No. 50-333

Public Service Electric and Gas Company — Docket No. 50-272
ATTN: Mr. F. W. Schneider
Vice President - Production
80 Park Place
Newark, New Jersey 07101

Rochester Gas and Electric Company — Docket No. 50-244
ATTN: Mr. Leon D. White, Jr.
Vice President
Electric and Steam Production
89 East Avenue
Rochester, New York 14649

Vermont Yankee Nuclear Power Corporation — Docket No. 50-271
ATTN: Mr. Robert H. Groce
Licensing Engineer
20 Turnpike Road
Westborough, Massachusetts 01581

Yankee Atomic Electric Company — Docket No. 50-29
ATTN: Mr. Robert H. Groce
Licensing Engineer
20 Turnpike Road
Westborough, Massachusetts 01581

Duquesne Light Company — Docket No. 50-412
ATTN: Mr. E. J. Woolever
Vice President
435 Sixth Avenue
Pittsburgh, Pennsylvania 15219

Jersey Central Power & Light Company — Docket No. 50-363
ATTN: Mr. I. R. Finfrock, Jr.
Vice President
260 Cherry Hill Road
Parsippany, New Jersey 07054

Long Island Lighting Company — Docket Nos. 50-322, 50-516, 50-517
ATTN: Mr. Andrew W. Wofford
Vice President
175 East Old Country Road
Hicksville, New York 11801

Niagara Mohawk Power Corporation — Docket No. 50-410
ATTN: Mr. G. K. Rhode
Vice President
System Project Management
300 Erie Boulevard, West
Syracuse, New York 13202

Pennsylvania Power & Light Company — Docket Nos. 50-387, 50-388
ATTN: Mr. Norman W. Curtis
Vice President
Engineering and Construction (N-4)
2 North Ninth Street
Allentown, Pennsylvania 18101

Philadelphia Electric Company — Docket Nos. 50-352, 50-353
ATTN: Mr. V. S. Boyer
Vice President
Engineering and Research
2301 Market Street
Philadelphia, Pennsylvania 19101

Public Service Electric & Gas Company — Docket Nos. 50-354, 50-355, 50-311
ATTN: Mr. T. J. Martin
Vice President
Engineering and Construction
80 Park Place
Newark, New Jersey 07101

Public Service Company of New Hampshire — Docket Nos. 50-443, 50-444
ATTN: Mr. W. C. Tallman
President
1000 Elm Street
Manchester, New Hampshire 03105

Rochester Gas & Electric Corporation — Docket No. 50-485
ATTN: Mr. J. E. Arthur
Chief Engineer
89 East Avenue
Rochester, New York 14649

Metropolitan Edison Company — Docket Nos. 50-289, 50-320
ATTN: Mr. J. G. Herbein
Vice President - Generation
P. O. Box 542
Reading, Pennsylvania 19640

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, DC 20555

APRIL 5, 1979

IE Bulletin 79-05A

NUCLEAR INCIDENT AT THREE MILE ISLAND - SUPPLEMENT

Description of Circumstances:

Preliminary information received by the NRC since issuance of IE Bulletin 79-05 on April 1, 1979 has identified six potential human, design and mechanical failures which resulted in the core damage and radiation releases at the Three Mile Island Unit 2 nuclear plant. The information and actions in this supplement clarify and extend the original Bulletin and transmit a preliminary chronology of the TMI accident through the first 16 hours (Enclosure 1).

1. At the time of the initiating event, loss of feedwater, both of the auxiliary feedwater trains were valved out of service.

2. The pressurizer electromatic relief valve, which opened during the initial pressure surge, failed to close when the pressure decreased below the actuation level.

3. Following rapid depressurization of the pressurizer, the pressurizer level indication may have led to erroneous inferences of high level in the reactor coolant system. The pressurizer level indication apparently led the operators to prematurely terminate high pressure injection flow, even though substantial voids existed in the reactor coolant system.

4. Because the containment does not isolate on high pressure injection (HPI) initiation, the highly radioactive water from the relief valve discharge was pumped out of the containment by the automatic initiation of a transfer pump. This water entered the radioactive waste treatment system in the auxiliary building where some of it overflowed to the floor. Outgassing from this water and discharge through the auxiliary building ventilation system and filters was the principal source of the offsite release of radioactive noble gases.

5. Subsequently, the high pressure injection system was intermittently operated attempting to control primary coolant inventory losses through the electromatic relief valve, apparently based on pressurizer level indication. Due to the presence of steam and/or noncondensible voids elsewhere in the reactor coolant system, this led to a further reduction in primary coolant inventory.

6. Tripping of reactor coolant pumps during the course of the transient, to protect against pump damage due to pump vibration, led to fuel damage since voids in the reactor coolant system prevented natural circulation.

Actions To Be Taken by Licensees:

For all Babcock and Wilcox pressurized water reactor facilities with an operating license (the actions specified below replace those specified in IE Bulletin 79-05):

1. (This item clarifies and expands upon item 1. of IE Bulletin 79-05.)

   In addition to the review of circumstances described in Enclosure 1 of IE Bulletin 79-05, review the enclosed preliminary chronology of the TMI-2 3/28/79 accident. This review should be directed toward understanding the sequence of events to ensure against such an accident at your facility(ies).

2. (This item clarifies and expands upon item 2. of IE Bulletin 79-05.)

   Review any transients similar to the Davis Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item.

3. (This item clarifies item 3. of IE Bulletin 79-05.)

   Review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed.

4. (This item clarifies and expands upon item 4. of IE Bulletin 79-05.)

Review the actions directed by the operating procedures and training instructions to ensure that:

a. Operators do not override automatic actions of engineered safety features.

b. Operating procedures currently, or are revised to, specify that if the high pressure injection (HPI) system has been automatically actuated because of low pressure condition, it must remain in operation until either:

(1) Both low pressure injection (LPI) pumps are in operation and flowing at a rate in excess of 1000 gpm each and the situation has been stable for 20 minutes, or

(2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing RCS pressure. If 50 degree subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated.

c. Operating procedures currently, or are revised to, specify that in the event of HPI initiation, with reactor coolant pumps (RCP) operating, at least one RCP per loop shall remain operating.

d. Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water inventory in the reactor primary system.

5. (This item revises item 5. of IE Bulletin 79-05.)

Verify that emergency feedwater valves are in the open position in accordance with item 8 below. Also, review all safety-related valve positions and positioning requirements to assure that valves are positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance and testing, to ensure that such valves are returned to their correct positions following necessary manipulations.

6. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to cause containment isolation of all lines whose isolation does not degrade core cooling capability upon automatic initiation of safety injection.

7. For manual valves or manually-operated motor-driven valves which could defeat or compromise the flow of auxiliary feedwater to the steam generators, prepare and implement procedures which:

   a. require that such valves be locked in their correct position; or

   b. require other similar positive position controls.

8. Prepare and implement immediately procedures which assure that two independent steam generator auxiliary feedwater flow paths, each with 100% flow capacity, are operable at any time when heat removal from the primary system is through the steam generators. When two independent 100% capacity flow paths are not available, the capacity shall be restored within 72 hours or the plant shall be placed in a cooling mode which does not rely on steam generators for cooling within the next 12 hours.

   When at least one 100% capacity flow path is not available, the reactor shall be made subcritical within one hour and the facility placed in a shutdown cooling mode which does not rely on steam generators for cooling within 12 hours or at the maximum safe shutdown rate.

9. (This item revises item 6 of IE Bulletin 79-05.)

   Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

10. Review and modify as necessary your maintenance and test procedures to ensure that they require:

    a. Verification, by inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

    b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

    c. A means of notifying involved reactor operating personnel whenever a safety-related system is removed from and returned to service.

11. All operating and maintenance personnel should be made aware of the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident.

12. Review your prompt reporting procedures for NRC notification to assure very early notification of serious events.

For Babcock and Wilcox pressurized water reactor facilities with an operating license, respond to Items 1, 2, 3, 4.a and 5 by April 11, 1979. Since these items are substantially the same as those specified in IE Bulletin 79-05, the required date for response has not been changed. Respond to Items 4.b through 4.d, and 6 through 12 by April 16, 1979.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, DC 20555.

For all other reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B 180225 (R0072); clearance expires 7-31-80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosures:

1. Preliminary Chronology of TMI-2 3/38/79 Accident Until Core Cooling Restored.

2. List of IE Bulletins issued in last 12 months.

PRELIMINARY

CHRONOLOGY OF TMI-2 3/28/79 ACCIDENT
UNTIL CORE COOLING RESTORED

TIME (Approximate)	EVENT
about 4 AM (t = 0)	Loss of Condensate Pump Loss of Feedwater Turbine Trip
t = 3-6 sec.	Electromatic relief valve opens (2255 psi) to relieve pressure in RCS
t = 9-12 sec.	Reactor trip on high RCS pressure (2355 psi)
t = 12-15 sec.	RCS pressure decays to 2205 psi (relief valve should have closed)
t = 15 sec.	RCS hot leg temperature peaks at 611 degrees F, 2147 psi (450 psi over saturation)
t = 30 sec.	All three auxiliary feedwater pumps running at pressure (Pumps 2A and 2B started at turbine trip). No flow was injected since discharge valves were closed.
t = 1 min.	Pressurizer level indication begins to rise rapidly
t = 1 min.	Steam Generators A and B secondary level very low - drying out over next couple of minutes.
t = 2 min.	ECCS initiation (HPI) at 1600 psi
t = 4 - 11 min.	Pressurizer level off scale - high - one HPI pump manually tripped at about 4 min. 30 sec. Second pump tripped at about 10 min. 30 sec.
t = 6 min.	RCS flashes as pressure bottoms out at 1350 psig (Hot leg temperature of 584 degrees F)
t = 7 min., 30 sec.	Reactor building sump pump came on.

TIME	EVENT
t = 8 min.	Auxiliary feedwater flow is initiated by opening closed valves
t = 8 min. 18 sec.	Steam Generator B pressure reached minimum
t = 8 min. 21 sec.	Steam Generator A pressure starts to recover
t = 11 min.	Pressurizer level indication comes back on scale and decreases
t = 11-12 min.	Makeup Pump (ECCS HPI flow) restarted by operators
t = 15 min.	RC Drain/Quench Tank rupture disk blows at 190 psig (setpoint 200 psig) due to continued discharge of electromatic relief valve
t = 20 - 60 min.	System parameters stabilized in saturated condition at about 1015 psig and about 550 degrees F.
t = 1 hour, 15 min.	Operator trips RC pumps in Loop B
t = 1 hour, 40 min.	Operator trips RC pumps in Loop A
t = 1-3/4 - 2 hours	CORE BEGINS HEAT UP TRANSIENT - Hot leg temperature begins to rise to 620 degrees F (off scale within 14 minutes) and cold leg temperature drops to 150 degrees F. (HPI water)
t = 2.3 hour	Electromatic relief valve isolated by operator after S.G.-B isolated to prevent leakage
t = 3 hours	RCS pressure increases to 2150 psi and electromatic relief valve opened
t = 3.25 hours	RC drain tank pressure spike of 5 psig
t = 3.8 hours	RC drain tank pressure spike of 11 psi - RCS pressure 1750; containment pressure increases from 1 to 3 psig
t = 5 hours	Peak containment pressure of 4.5 psig
t = 5 - 6 hours	RCS pressure increased from 1250 psi to to 2100 psi

TIME	EVENT
t = 7.5 hours	Operator opens electromatic relief valve to depressurize RCS to attempt initiation of RHR at 400 psi
t = 8 - 9 hours	RCS pressure decreases to about 500 psi Core Flood Tanks partially discharge
t = 10 hour	28 psig containment pressure spike, containment sprays initiated and stopped after 500 gal. of NaOH injected (about 2 minutes of operation)
t = 13.5 hours	Electromatic relief valve closed to repressurize RCS, collapse voids, and start RC pump
t = 13.5 - 16 hours	RCS pressure increased from 650 psi to 2300 psi
t = 16 hours	RC pump in Loop A started, hot leg temperature decreases to 560 degrees F, and cold leg temperature increases to 400 degrees F. indicating flow through steam generator
Thereafter	S/G "A" steaming to condenser Condenser vacuum re-established RCS cooled to about 280 degrees F., 1000 psi
Now (4/4)	High radiation in containment All core thermocouples less than 460 degrees F. Using pressurizer vent valve with small makeup flow Slow cooldown RB pressure negative

LISTING OF IE BULLETINS ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism - General Electric Model CR105X	4/14/78	All Power Reactor Facilities with an Operating License (OL) or Construction Permit (CP)
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority I Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power, Test and Research Reactor Facilities with an OL having Fuel Element Transfer Tubes
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/78	All BWR Power Reactor Facilities with an OL (for action) or CP (for information)
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/24/78	BWR Power Reactor Facilities with an OL for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee. All other BWR Power Reactor Facilities with an OL for information
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All General and Specific Licensees with the subject Kay-Ray, Inc. Gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR Facilities with an OL (for action), and all other Power Reactor Facilities with an OL or CP (for information)

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL, except the 11 Systematic Evaluation Program Plants (for action), and all other Power Reactor Facilities with an OL or CP (for information)
79-02	Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts	3/8/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured by Youngstown Welding and Engineering Company	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All Babcock and Wilcox Power Reactor Facilities with an OL, Except Three Mile Island 1 and 2 (For Action), and All Other Power Reactor Facilities With an OL or CP (For Information)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, DC 20555

APRIL 21, 1979

IE Bulletin 79-05B

NUCLEAR INCIDENT AT THREE MILE ISLAND - SUPPLEMENT

Description of Circumstances:

Continued NRC evaluation of the nuclear incident at Three Mile Island Unit 2 has identified measures in addition to those discussed in IE Bulletin 79-05 and 79-05A which should be acted upon by licensees with reactors designed by B&W. As discussed in Item 4.c. of Actions to be taken by Licensees in IEB 79-05A, the preferred mode of core cooling following a transient or accident is to provide forced flow using reactor coolant pumps.

It appears that natural circulation was not successfully achieved upon securing the reactor coolant pumps during the first two hours of the Three Mile Island (TMI) No. 2 incident of March 28, 1979. Initiation of natural circulation was inhibited by significant coolant voids, possibly aggravated by release of noncondensible gases, in the primary coolant system. To avoid this potential for interference with natural circulation, the operator should ensure that the primary system is subcooled, and remains subcooled, before any attempt is made to establish natural circulation.

Natural circulation in Babcock and Wilcox reactor systems is enhanced by maintaining a relatively high water level on the secondary side of the once through steam generators (OTSG). It is also promoted by injection of auxiliary feedwater at the upper nozzles in the OTSGs. The integrated Control System automatically sets the OTSG level setpoint to 50% on the operating range when all reactor coolant pumps (RCP) are secured. However, in unusual or abnormal situations, manual actions by the operator to increase steam generator level will enhance natural circulation capability in anticipation of a possible loss of operation of the reactor coolant pumps. As stated previously, forced flow of primary coolant through the core is preferred to natural circulation.

Other means of reducing the possibility of void formation in the reactor coolant system are:

A. Minimize the operation of the Power Operated Relief Valve (PORV) on the pressurizer and thereby reduce the possibility of pressure reduction by a blowdown through a PORV that was stuck open.

B. Reduce the energy input to the reactor coolant system by a prompt reactor trip during transients that result in primary system pressure increases.

This bulletin addresses, among other things, the means to achieve these objectives.

Actions To Be Taken by Licensees:

For all Babcock and Wilcox pressurized water reactor facilities with an operating license: (Underlined sentences are modifications to, and supersede, IEB-79-05A).

1. Develop procedures and train operation personnel on methods of establishing and maintaining natural circulation. The procedures and training must include means of monitoring heat removal efficiency by available plant instrumentation. The procedures must also contain a method of assuring that the primary coolant system is subcooled by at least 50°F before natural circulation is initiated.

   In the event that these instructions incorporate anticipatory filling of the OTSG prior to securing the reactor coolant pumps, a detailed analysis should be done to provide guidance as to the expected system response. The instructions should include the following precautions:

   a. maintain pressurizer level sufficient to prevent loss of level indication in the pressurizer;

   b. assure availability of adequate capacity of pressurizer heaters, for pressure control and maintain primary system pressure to satisfy the subcooling criterion for natural circulation;

   c. maintain pressure - temperature envelope within Appendix G limits for vessel integrity.

   Procedures and training shall also be provided to maintain core cooling in the event both main feedwater and auxiliary feedwater are lost while in the natural circulation core cooling mode.

2. Modify the actions required in Item 4a and 4b of IE Bulletin 79-05A to take into account vessel integrity considerations.

   "4. Review the action directed by the operating procedures and training instructions to ensure that:

      a. Operators do not override automatic actions of engineered safety features, <u>unless continued operation of engineered</u>

safety features will result in unsafe plant conditions. For example, if continued operation of engineered safety features would threaten reactor vessel integrity then the HPI should be secured (as noted in b(2) below).

b. Operating procedures currently, or are revised to, specify that if the high pressure injection (HPI) system has been automatically actuated because of low pressure condition, it must remain in operation until either:

(1) Both low pressure injection (LPI) pumps are in operation and flowing at a rate in excess of 1000 gpm each and the situation has been stable for 20 minutes, or

(2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing RCS pressure. If 50 degrees subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50 degrees F and the length of time HPI is in operation shall be limited by the pressure/temperature considerations for the vessel integrity."

3. Following detailed analysis, describe the modifications to design and procedures which you have implemented to assure the reduction of the likelihood of automatic actuation of the pressurizer PORV during anticipated transients. This analysis shall include consideration of a modification of the high pressure scram setpoint and the PORV opening setpoint such that reactor scram will preclude opening of the PORV for the spectrum of anticipated transients discussed by B&W in Enclosure 1. Changes developed by this analysis shall not result in increased frequency of pressurizer safety valve operation for these anticipated transients.

4. Provide procedures and training to operating personnel for a prompt manual trip of the reactor for transients that result in a pressure increase in the reactor coolant system. These transients include:

a. loss of main feedwater

b. turbine trip

c. Main Steam Isolation Valve closure

d. Loss of offsite power

e. Low OTSG level

f. low pressurizer level.

5. Provide for NRC approval a design review and schedule for implementation of a safety grade automatic anticipatory reactor scram for loss of feedwater, turbine trip, or significant reduction in steam generator level.

6. The actions required in item 12 of IE Bulletin 79-05A are modified as follows:

   Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

7. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the above items.

Response schedule for B&W designed facilities:

a. For Items 1, 2, 4 and 6, all facilities with an operating license respond within 14 days of receipt of this Bulletin.

b. For Item 3, all facilities currently operating, respond within 24 hours. All facilities with an operating license, not currently operating, respond before resuming operation.

c. For Items 5 and 7, all facilities with an operating license respond in 30 days.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D. C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

INTRODUCTION

THE CONTINUING REVIEW OF THE SEQUENCE OF EVENTS LEADING TO THE INCIDENT AT TMI-2 ON MARCH 28, 1979 SHOWS THAT ACTION CAN BE TAKEN TO PROVIDE ASSURANCE THAT THE PILOT-OPERATED RELIEF VALVE (PORV) MOUNTED ON THE PRESSURIZER OF B&W PLANTS WILL NOT BE ACTUATED BY ANTICIPATED TRANSIENTS WHICH HAVE OCCURRED OR HAVE A SIGNIFICANT PROBABILITY OF OCCURRING IN THESE PLANTS. THIS ACTION MUST NOT DEGRADE THE SAFETY OF THE AFFECTED PLANTS WITH RESPECT TO THEIR RESPONSE TO NORMAL, UPSET OR ACCIDENT CONDITIONS NOR LEAD TO UNREVIEWED SAFETY CONCERNS. THE ANTICIPATED TRANSIENTS OF CONCERN ARE:

1. LOSS OF EXTERNAL ELECTRICAL LOAD
2. TURBINE TRIP
3. LOSS OF MAIN FEEDWATER
4. LOSS OF CONDENSER VACUUM
5. INADVERTENT CLOSURE OF MAIN STEAM ISOLATION VALVES (MSIV).

A NUMBER OF ALTERNATIVES WERE CONSIDERED IN DEVELOPING THE ACTIONS PROPOSED BELOW INCLUDING:

1. RESTRICTING REACTOR POWER TO A VALUE WHICH WOULD ASSURE NO ACTUATION OF THE PORV. THE REACTOR PROTECTION SYSTEM, DESIGN PRESSURE AND PORV SETPOINTS REMAINED AT THEIR CURRENT VALUES.

2. LOWERING THE HIGH PRESSURE REACTOR TRIP SETPOINT TO A VALUE WHICH WOULD ASSURE NO ACTUATION OF THE PORV. THE DESIGN PRESSURE OF THE REACTOR AND THE SETPOINT FOR PORV ACTUATION REMAINED AT THEIR CURRENT VALUES.

 LOWERING THE HIGH PRESSURE REACTOR TRIP SETPOINT AND ADJUSTING THE OPERATING PRESSURE (AND TEMPERATURE) OF THE REACTOR TO ASSURE NO PORV ACTUATION AND TO PROVIDE ADEQUATE MARGIN TO ACCOMMODATE VARIATIONS IN OPERATING PRESSURE. THE SETPOINT FOR PORV ACTUATION REMAINED AT ITS CURRENT VALUE. THIS ALTERNATIVE WOULD REDUCE NET ELECTRICAL OUTPUT.

4. ADJUSTING THE HIGH PRESSURE TRIP AND THE PORV SETPOINTS TO ASSURE NO PORV ACTUATION FOR THE CLASS OF ANTICIPATED EVENTS OF CONCERN. THE DESIGN PRESSURE OF THE REACTOR REMAINED AT ITS CURRENT VALUE.

AN ANALYSIS OF THE IMPACT OF THESE VARIOUS ALTERNATIVES AND THEIR CONTRIBUTION TO ASSURING THAT THE PORV WILL NOT ACTUATE FOR THE CLASS OF ANTICIPATED TRANSIENT OF CONCERN HAS BEEN COMPLETED. THE RESULTS SHOW THAT:

LOWERING THE HIGH PRESSURE REACTOR TRIP SETPOINT FROM <u>2355 PSIG TO 2300 PSIG</u>

AND

RAISING THE SETPOINT FOR THE PILOT OPERATED RELIEF VALVE FROM <u>2255 PSIG TO 2450 PSIG</u>

PROVIDES THE REQUIRED ASSURANCE. THIS ACTION HAS THE FURTHER ADVANTAGES OF:

EXTRACT OF B&W COMMUNICATION - RECEIVED BY NRC
4/20/79

1. REDUCING THE PROBABILITY OF PORV AND ASME CODE PRESSURIZER SAFETY VALVE ACTUATION FOR OTHER INCREASING PRESSURE TRANSIENTS.

2. PRESERVING PRESSURE RELIEF CAPACITY FOR ALL HIGH PRESSURE TRANSIENTS.

3. ELIMINATING THE POSSIBILITY OF INTRODUCING UNREVIEWED SAFETY CONCERNS.

4. REDUCING THE TIME AT WHICH THE STEAM SYSTEM HEAT SINK WOULD BE LOST IN THE EVENT EMERGENCY FEEDWATER FLOW WERE DELAYED.

A SUMMARY OF THE IMPACT OF THE PROPOSED SETPOINT CHANGES ON ALL ANTICIPATED TRANSIENTS IS GIVEN IN TABLE 1.

B&W PLANTS ARE CURRENTLY CAPABLE OF RUNBACK TO 15% OF FULL POWER UPON LOSS OF LOAD OR TRIP OF THE TURBINE. THIS CAPABILITY REQUIRES ACTUATION OF THE PILOT-OPERATED RELIEF VALVES. THE CAPABILITY INCREASES THE RELIABILITY OF POWER SUPPLY TO THE SYSTEM BY RETURNING THE UNITS TO POWER GENERATION MORE QUICKLY AFTER THESE TRANSIENTS. THE ACTION PROPOSED ABOVE WILL REQUIRE THAT THE REACTOR BE TRIPPED FOR THESE EVENTS.

NRC NOTE:

The effect of changing the reactor coolant system pressure trip setpoint upon peak pressurizer pressure is typified by the attached figure 1. which was developed by B&W for a loss of feedwater transient.

TABLE 1

SUMMARY OF PROTECTION AGAINST PORV ACTUATION
PROVIDED BY PROPOSED SETPOINT CHANGES FOR ALL
ANTICIPATED TRANSIENTS

EXTRACT OF B&W COMMUNICATION - RECEIVED BY NRC 4/20/79

1. ANTICIPATED TRANSIENTS WHICH HAVE OCCURRED AT B&W PLANTS AND WHICH WOULD NORMALLY ACTIVATE PORV AT THE CURRENT SETPOINT (2255 PSIG):

   A. TURBINE TRIP
   B. LOSS OF EXTERNAL ELECTRICAL LOAD
   C. LOSS OF MAIN FEEDWATER
   D. LOSS OF CONDENSER VACUUM
   E. INADVERTENT CLOSURE OF MSIV

2. ANTICIPATED TRANSIENTS WHICH HAVE OCCURRED AT B&W PLANTS AND WHICH WOULD NORMALLY ACTUATE PORV AT THE PROPOSED SETPOINT (2450 PSIG):

   NONE

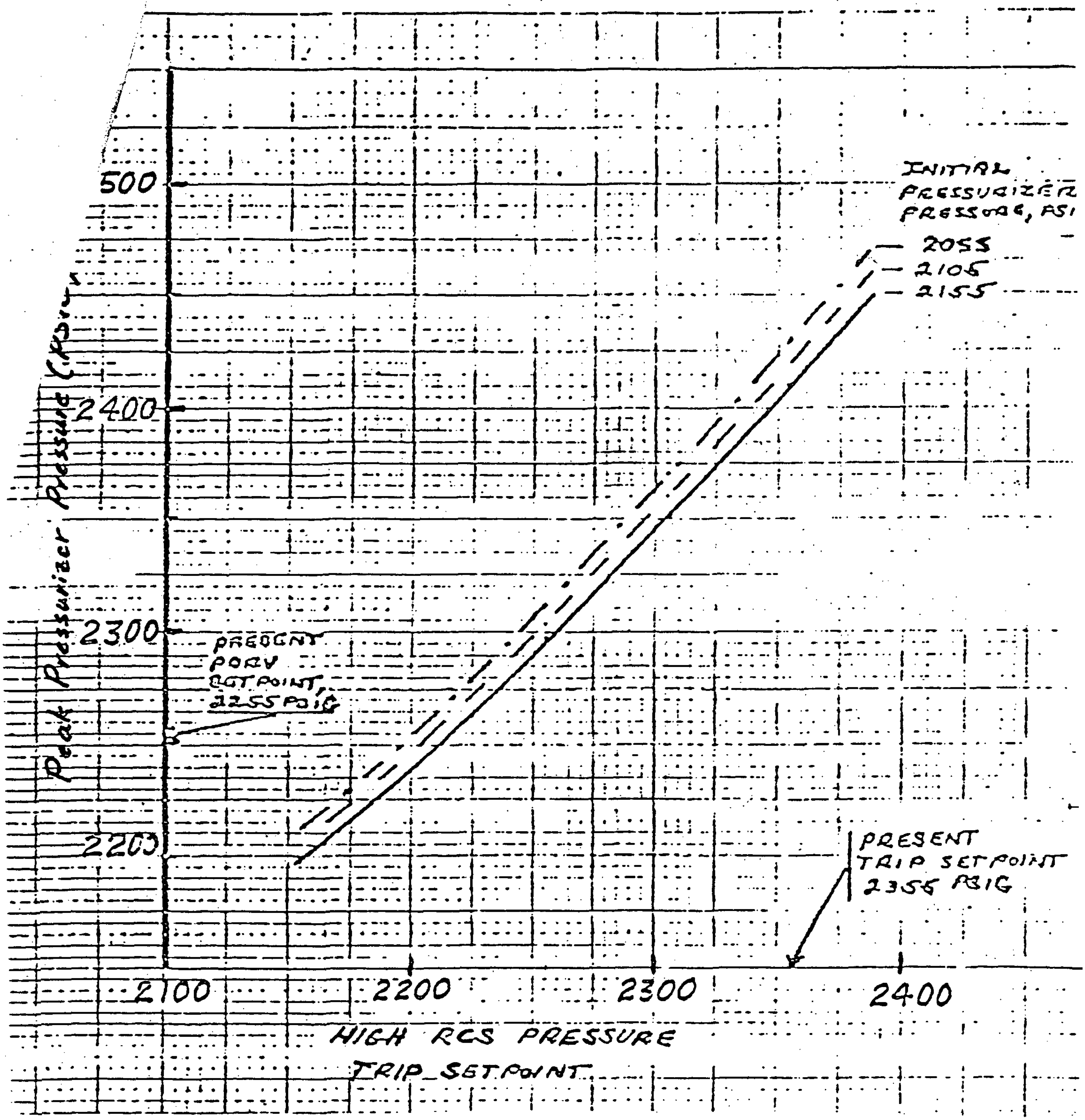
3. ANTICIPATED TRANSIENTS WHICH HAVE NOT OCCURRED AT B&W PLANTS (LOW PROBABILITY EVENTS) AND WHICH WOULD NORMALLY ACTUATE PORV AT THE CURRENT SETPOINT (2255 PSIG):

   A. SOME CONTROL ROD GROUP WITHDRAWALS (MODERATE TO HIGH REACTIVITY WORTH GROUPS NOT OTHERWISE PROTECTED BY HIGH FLUX TRIP).
   B. MODERATOR DILUTION.

4. ANTICIPATED TRANSIENTS WHICH HAVE NOT OCCURRED AT B&W PLANTS (LOW PROBABILIT EVENTS) AND WHICH WOULD ACTUATE THE PORV AT THE PROPOSED SETPOINT (2450 PSIG):

   A. SOME CONTROL ROD GROUP WITHDRAWALS (HIGH REACTIVITY WORTH NOT OTHERWISE PROTECTED BY HIGH FLUX TRIP).

EXTRACT OF B&W COMMUNICATION - RECEIVED BY NRC
4/20/79



Peak pressurizer pressure as a function of RCS pressure trip setpoint for a loss of feedwater transient for expected conditions and various initial pressures.

Figure 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

April 11, 1979

IE Bulletin No. 79-06

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

As previously discussed in IE Bulletin 79-05 and 79-05A, the Three Mile Island Nuclear Power Plant, Unit 2 experienced significant core damage which resulted from a series of events initiated by a loss of feedwater transient and apparently compounded by operational errors. Several aspects of the incident have generic applicability to all light water power reactor facilities, in addition to those previously identified as applicable to Babcock and Wilcox reactors. This bulletin is to identify certain actions to be taken by all other light water power reactor facilities with an operating license. Actions previously have been required of licensees with B&W reactors.

Action to be taken by licensees:

For all pressurized water power reactor facilities with an operating license except Babcock and Wilcox reactors:

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

   b. Operations personnel should be instructed to: (1) not override automatic action of engineered safety features without careful review of plant conditions; and (2) not make operational decisions based on a single plant parameter indication when a confirmatory indication is available.

   c. All licensed operators and plant management and supervision with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

2. For pressurized water reactor facilities review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed.

3. For pressurized water reactor facilities that use pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, instruct operators to manually initiate safety injection when the pressurizer pressure indication reaches the actuation set point whether or not the level indication has dropped to the actuation set point.

4. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to cause containment isolation of all lines whose isolation does not degrade core cooling capability upon automatic initiation of safety injection.

5. For pressurized water reactor facilities for which the auxiliary feedwater system is not automatically initiated, prepare and implement immediately procedures which require the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which can be limited by such action.

6. For all pressurized water reactors, prepare and implement immediately procedures which:

   a. Identify those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators may utilize to determine that pressurizer power operated relief valve(s) are open, and

b. Direct the plant operators to manually close the power operated relief block valve(s) when reactor coolant system pressure is reduced to the set point for normal automatic closure of the power operated relief valve(s) and the valve(s) fail to close.

7. Review the action directed by the operating procedures and training instructions to ensure that:

a. Operators do not override automatic actions of engineered safety features without careful review of plant conditions.

b. Operators are provided additional information and instructions to not rely upon any one plant parameter but to also examine other related indications in evaluating plant conditions.

8. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (daily/shift checks, etc.) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

9. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

b. Whether such systems are isolated by the containment isolation signal.

c. The basis on which continued operability of the above features is assured.

10. Review and modify as necessary your maintenance and test procedures to ensure that they require:

a. Verification, by test or inspection per technical specifications, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

c. Explicit notification of involved reactor operating personnel whenever a safety-related system is removed from and returned to service.

11. Review your prompt reporting procedures for NRC notification to assure very early notification of serious events.

For all pressurized water power reactor facilities with an operating license except Babcock and Wilcox reactors, respond to Items 1-11 within 14 days of the receipt of this Bulletin.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D.C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism-General Model CR105X	4/14/78	All Power Reactor Facilities with an OL or CP
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority 1 Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power and Research Reactor Facilities with a Fuel Element transfer tube and an OL.
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/79	All BWR Power Reactor Facilities with an OL or CP
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/21/78	BWR Power Reactor Facilities for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All general and specific licensees with the subject Kay-Ray, Inc. gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR facilities with an OL or CP
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-02	Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts	3/2/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects In ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured By Youngstown Welding and Engineering Co.	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All B&W Power Reactor Facilities with an OL
79-05A	Nuclear Incident at Three Mile Island	4/5/79	All B&W Power Reactor Facilities with an OL

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

Description of Circumstances:

IE Bulletin 79-06 identified actions to be taken by the licensees of all pressurized water power reactors (except Babcock & Wilcox reactors) as a result of the Three Mile Island Unit 2 incident. This Bulletin clarifies the actions of Bulletin 79-06 for reactors designed by Westinghouse, and the response to this bulletin will eliminate the need to respond to Bulletin 79-06.

Actions to be taken by Licensees:

For all Westinghouse pressurized water reactor facilities with an operating license (the actions specified below replace those identified in IE Bulletin 79-06 on an item by item basis):

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; (3) that the potential exists, under certain accident or transient conditions, to have a water level in the pressurizer simultaneously with the reactor vessel not full of water; and (4) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

   b. Operational personnel should be instructed to: (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 7a.); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

2. Review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed. (e.g., remote venting)

3. For your facilities that use pressurizer water level coincident pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, trip the low pressurizer level setpoint bistables such that, when the pressurizer pressure reaches the low setpoint, safety injection would be initiated regardless of the pressurizer level. In addition, instruct operators to manually initiate safety injection when the pressurizer pressure indication reaches the actuation setpoint whether or not the level indication has dropped to the actuation setpoint.

4. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to permit containment isolation whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

5. For facilities for which the auxiliary feedwater system is not automatically initiated, prepare and implement immediately procedures which require the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate adequate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which can be limited by such action.

6. For your facilities, prepare and implement immediately procedures which:

   a. Identify those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators may utilize to determine that pressurizer power operated relief valve(s) are open, and

   b. Direct the plant operators to manually close the power operated relief block valve(s) when reactor coolant system pressure is reduced to below the set point for normal automatic closure of the power operated relief valve(s) and the valve(s) remain stuck open.

7. Review the action directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions. For example, if continued operation of engineered safety features would threaten reactor vessel integrity then the HPI should be secured (as noted in b(2) below).

   b. Operating procedures currently, or are revised to, specify that if the high pressure injection (HPI) system has been automatically actuated because of low pressure condition, it must remain in operation until either:

      (1) Both low pressure injection (LPI) pumps are in operation and flowing for 20 minutes or longer; at a rate which would assure stable plant behavior; or

      (2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing RCS pressure. If 50 degress subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50 degrees F and the length of time HPI is in operation shall be limited by the pressure/temperature considerations for the vessel integrity.

c. Operating procedures currently, or are revised to, specify that in the event of HPI initiation with reactor coolant pumps (RCP) operating, at least one RCP shall remain operating for two loop plants and at least two RCPs shall remain operating for 3 or 4 loop plants as long as the pump(s) is providing forced flow.

d. Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water, inventory in the reactor primary system.

8. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks,) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

9. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

10. Review and modify as necessary your maintenance and test procedures to ensure that they require:

    a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

11 Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

12. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

13. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the above items.

For all light water reactor facilities designed by Westinghouse with an operating license, respond to Items 1-12 within 10 days of the receipt of this Bulletin. Respond to item 13 (Technical Specification Change proposals) in 30 days.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D.C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosure:
List of IE Bulletins Issued in Last
Twelve Months

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism - General Electric Model CR105X	4/14/78	All Power Reactor Facilities with an Operating License (OL) or Construction Permit (CP)
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority I Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power, Test and Research Reactor Facilities with an OL having Fuel Element Transfer Tubes
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/78	All BWR Power Reactor Facilities with an OL (for action) or CP (for information)
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/24/78	BWR Power Reactor Facilities with an OL for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee. All other BWR Power Reactor Facilities with an OL for information
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All General and Specific Licensees with the subject Kay-Ray, Inc. Gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR Facilities with an OL (for action), and all other Power Reactor Facilities with an OL or CP (for information)

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL, except the 11 Systematic Evaluation Program Plants (for action), and all other Power Reactor Facilities with an OL or CP (for information)
79-02	Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts	3/8/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured by Youngstown Welding and Engineering Company	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All Babcock and Wilcox Power Reactor Facilities with an OL, Except Three Mile Island 1 and 2 (For Action), and All Other Power Reactor Facilities With an OL or CP (For Information)
79-05A	Nuclear Incident at Three Mile Island - Supplement	4/5/79	Same as 79-05

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-06	Review of Operational Errors and System Mis-alignments Identified During the Three Mile Incident	4/11/79	All Pressurized Water Power Reactor Facilities with an OL Except B&W Facilities (For Action), All Other Power Reactor Facilities With an OL or CP (For Information)

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

REGION III

April 18, 1979

IE Bulletin No. 79-06A
(Revision No. 1)

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

IE Bulletin 79-06A identified actions to be taken by the licensees of all pressurized water reactors designed by Westinghouse.

Item No. 3 of the actions to be taken, as stated in the original bulletin, was:

> "3. For your facilities that use pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, trip the low pressurizer level setpoint bistables such that, when the pressurizer pressure reaches the low setpoint, safety injection would be initiated regardless of the pressurizer level. In addition, instruct operators to manually initiate safety injection when the pressurizer pressure indication reaches the actuation setpoint whether or not the level indication has dropped to the actuation setpoint."

Information from licensees and Westinghouse has identified that implementation of this action would preclude the performance of surveillance testing of the pressurizer pressure bistables without initiating a safety injection.

In order to permit surveillance testing of the pressurizer pressure bistables, the low pressurizer level bistables that must operate in coincidence with the low pressurizer pressure bistables may be restored to normal operation for the duration of the surveillance test of that coincident pressurizer pressure channel. At the conclusion of the surveillance test of each pressurizer pressure channel, the coincident pressurizer level channel must be returned to the tripped mode defined in Action Item 3 of IE Bulletin 79-06A.

As a result, Item 3 should be revised as follows:

"3. For your facilities that use pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, trip the low pressurizer level setpoint bistables such that, when the pressurizer pressure reaches the low setpoint, safety injection would be initiated regardless of the pressurizer level. The pressurizer level bistables may be returned to their normal operating positions during the pressurizer pressure channel functional surveillance tests. In addition, instruct operators to manually initiate safety injection when the pressurizer pressure indication reaches the actuation setpoint whether or not the level indication has dropped to the actuation setpoint."

Item 13 of the actions to be taken, as stated in the original bulletin, was:

"13. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the above items."

Long term resolutions of some of these required actions may require design changes. Therefore, Item 13 of actions to be taken should be revised as follows:

"13. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the above items and identify design changes necessary in order to effect long term resolutions of these items."

For all light water reactor facilities designed by Westinghouse with an operating license, respond to Items 1-12 within 10 days of the receipt of this Bulletin. Respond to Item 13 (Technical Specification Change proposals and identification of design changes in 30 days.)

The other requirements of IE Bulletin 79-06A remain in effect.

Approved by GAO, B180225 (R0072); clearance expires 7-31-80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosure: Listing of
IE Bulletins Issued
in Last Twelve Months

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-09	Failure of GE Type AK-2 Circuit Breaker In Safety Related Systems	4/17/79	All Power Reactor Facilities with an OL
79-08	Events Relevant to BWR Reactors Identified During Three Mile Island Incident	4/14/79	All BWR Power Reactor Facilities with an OL
79-07	Seismic Stress Analysis of Safety-Related Piping	4/14/79	All Power Reactor Facilities with an OL or CP
79-06B	Review of Operational Errors and System Mis-alignments Identified During the Three Mile Island Incident	4/14/79	All Combustion Engineer-ing Designed Pressurized Water Power Reactor Facilities with an Operating Licensee
79-06A	Review of Operational Errors and System Mis-alignments Identified During the Three Mile Island Incident	4/14/79	All Pressurized Water Power Reactor Facilities of Westinghouse Design with an OL
79-06	Review of Operational Errors and System Mis-alignments Identified During the Three Mile Island Incident	4/11/79	All Pressurized Water Power Reactors with an OL except B&W facilities
79-05A	Nuclear Incident at Three Mile Island	4/5/79	All B&W Power Reactor Facilities with an OL
79-05	Nuclear Incident at Three Mile Island	4/2/79	All Power Reactor Facilities with an OL and CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured by Youngstown Welding and Engineering Co.	3/12/79	All Power Reactor Facilities with an OL or CP
79-02	Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts	3/2/79	All Power Reactor Facilities with an OL or CP
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL or CP
78-14	Deterioration of BUNA-N Components in ASCO	12/19/78	All GE BWR facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7950, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All general and specific licensees with the subject Kay-Ray, Inc. gauges
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/21/78	BWR Power Reactor Facilities for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/79	All BWR Power Reactor Facilities with an OL or CP
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power and Research Reactor Facilities with a Fuel Element transfer tube and an OL
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority 1 Material Licensees
78-06	Defective Cutler-Hammer Type M Relays with DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

Description of Circumstances:

IE Bulletin 79-06 identified actions to be taken by the licensees of all pressurized water power reactors (except Babcock & Wilcox reactors) as a result of the Three Mile Island Unit 2 incident. This Bulletin clarifies the actions of Bulletin 79-06 for reactors designed by Combustion Engineering, and the response to this bulletin will eliminate the need to respond to Bulletin 79-06.

Actions to be taken by Licensees:

For all Combustion Engineering pressurized water reactor facilities with an operating license (the actions specified below replace those identified in IE Bulletin 79-06 on an item by item basis):

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; (3) that the potential exists, under certain accident or transient conditions, to have a water level in the pressurizer simultaneously with the reactor vessel not full of water; and (4) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

   b. Operational personnel should be instructed to: (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 6a.); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

2. Review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed. (e.g., remote venting)

3. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to permit containment isolation whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

4. For facilities for which the auxiliary feedwater system is not automatically initiated, prepare and implement immediately procedures which require the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate adequate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which can be limited by such action.

5. For your facilities, prepare and implement immediately procedures which:

   a. Identify those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators may utilize to determine that pressurizer power operated relief valve(s) are open, and

   b. Direct the plant operators to manually close the power operated relief block valve(s) when reactor coolant system pressure is reduced to below the set point for normal automatic closure of the power operated relief valve(s) and the valve(s) remain stuck open.

6. Review the action directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions. For example, if continued operation of engineered safety features would threaten reactor vessel integrity then the HPI should be secured (as noted in b(2) below).

   b. Operating procedures currently, or are revised to, specify that if the high pressure injection (HPI) system has been automatically actuated because of low pressure condition, it must remain in operation until either:

      (1) Both low pressure injection (LPI) pumps are in operation and flowing for 20 minutes or longer; at a rate which would assure stable plant behavior; or

      (2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing RCS pressure. If 50 degress subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50 degrees F and the length of time HPI is in operation shall be limited by the pressure/temperature considerations for the vessel integrity.

   c. Operating procedures currently, or are revised to, specify that in the event of HPI initiation with reactor coolant pumps (RCP) operating, at least one RCP shall remain operating in each loop as long as the pump(s) is providing forced flow.

   d. Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water, inventory in the reactor primary system.

7. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks,) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

8. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

9. Review and modify as necessary your maintenance and test procedures to ensure that they require:

   a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

   b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

   c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

10. Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

11. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

12. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the above items.

For all light water reactor facilities designed by Combustion with an operating license, respond to Items 1-11 within 10 days of the receipt of this Bulletin. Respond to item 12 (Technical Specification Change proposals) in 30 days.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D.C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosure:
List of IE Bulletins Issued in Last
Twelve Months

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism - General Electric Model CR105X	4/14/78	All Power Reactor Facilities with an Operating License (OL) or Construction Permit (CP)
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority I Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power, Test and Research Reactor Facilities with an OL having Fuel Element Transfer Tubes
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/78	All BWR Power Reactor Facilities with an OL (for action) or CP (for information)
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/24/78	BWR Power Reactor Facilities with an OL for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee. All other BWR Power Reactor Facilities with an OL for information
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All General and Specific Licensees with the subject Kay-Ray, Inc. Gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR Facilities with an OL (for action), and all other Power Reactor Facilities with an OL or CP (for information)

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL, except the 11 Systematic Evaluation Program Plants (for action), and all other Power Reactor Facilities with an OL or CP (for information)
79-02	Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts	3/8/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured by Youngstown Welding and Engineering Company	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All Babcock and Wilcox Power Reactor Facilities with an OL, Except Three Mile Island 1 and 2 (For Action), and All Other Power Reactor Facilities With an OL or CP (For Information)
79-05A	Nuclear Incident at Three Mile Island - Supplement	4/5/79	Same as 79-05

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS (CONTINUED)

Bulletin No.	Subject	Date Issued	Issued to
79-06	Review of Operational Errors and System Misalignments Identified During the Three Mile Incident	4/11/79	All Pressurized Water Power Reactor Facilities with an OL Except B&W Facilities (For Action), All Other Power Reactor Facilities With an OL or CP (For Information)
79-06A	Same Title as 79-06	4/14/79	All Westinghouse Designed Pressurized Power Reactor Facilities with an OL (For Action), and All Other Power Reactor Facilities with an OL or CP (For Information)

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

REGION III

April 14, 1979

IE Bulletin No. 79-08

EVENTS RELEVANT TO BOILING WATER POWER REACTORS IDENTIFIED DURING THREE MILE ISLAND INCIDENT

Description of Circumstances:

On march 28, 1979 the Three Mile Island Nuclear Power Plant, Unit 2 experienced core damage which resulted from a series of events which were initiated by a loss of feedwater transient. Several aspects of the incident may have general applicability to operating boiling water reactors. This bulletin requests certain actions of licensees of operating boiling water reactors.

Actions to be taken by Licensees:

For all Boiling water reactor facilities with an operating license complete the actions specified below:

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

   b. Operational personnel should be instructed to (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 5a of this bulletin); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

2. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

3. Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure, by which this action is taken in a timely sense.

4. Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems.

5. Review the action directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions (e.g. vessel integrity).

   b. Operators are provided additional information and instructions to not rely upon vessel level indication alone for manual actions, but to also examine other plant parameter indications in evaluating plant conditions.

6. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks,) surveillance to to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

7. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

8. Review and modify as necessary your maintenance and test procedures to ensure that they require:

   a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

   b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

   c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

9. Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

10. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

11. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the items above.

For all boiling water reactor facilities with an operating license, respond to Items 1-10 within 10 days of the receipt of this Bulletin. Respond to item 11 (Technical Specification Change proposals) in 30 days.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D.C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosure: Listing of IE Bulletins Issued in Last Twelve Months

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism-General Model CR105X	4/14/78	All Power Reactor Facilities with an OL or CP
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority 1 Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power and Research Reactor Facilities with a Fuel Element transfer tube and an OL.
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/79	All BWR Power Reactor Facilities with an OL or CP
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/21/78	BWR Power Reactor Facilities for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All general and specific licensees with the subject Kay-Ray, Inc. gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR facilities with an OL or CP
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL or CP

LISTING OF IE BULLETINS ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-02	Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts	3/2/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects In ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured By Youngstown Welding and Engineering Co.	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All B&W Power Reactor Facilities with an OL
79-05A	Nuclear Incident at Three Mile Island	4/5/79	All B&W Power Reactor Facilities with an OL
79-06	Review of Operational Errors and System Misalignments Identified During The Three Mile Island Incident	4/11/79	All Pressurized Water Power Reactor Facilit-ies Except B&W Facilit ies
79-06 A	Review of Operational Errors and System Misalignments Identified During The Three Mile Island Incident	4/11/79	All Westinghouse PWR Facilities with an OL
79-06B	Review of Operational Errors and System Misalignments Identified During The Three Mile Island Incident	4/11/79	All Combustion Engineer-ing PWR Facilities with an OL

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-07	Seismic Stress Analysis of Safety Related Piping	4/14/79	All Power Reactor Facilities with an OL or CP
79-08	Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident	4/14/79	All Power Reactor Facilities with an OL or CP

APPENDIX Y

COMMISSION SHUTDOWN ORDERS

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of)
)
SACRAMENTO MUNICIPAL UTILITY DISTRICT) Docket No. 50-312
)
Rancho Seco Nuclear Generating Station)

ORDER

I.

The Sacramento Municipal Utility District (the licensee or SMUD) is the holder of Facility Operating License No. DPR-54 which authorizes the operation of the nuclear power reactor known as the Rancho Seco Nuclear Generating Station (the facility or Rancho Seco), at steady state power levels not in excess of 2772 megawatts thermal (rated power). The facility is a Babcock & Wilcox (B&W) designed pressurized water reactor (PWR) located at the licensee's site in Sacramento County, California.

II.

In the course of its evaluation to date of the accident at the Three Mile Island Unit No. 2 facility, which utilizes a B&W designed PWR, the Nuclear Regulatory Commission staff has ascertained that B&W designed reactors appear to be unusually sensitive to certain off-normal transient conditions originating in the secondary system. The features of the B&W design that contribute to this sensitivity are: (1) design of the steam generators to operate with relatively small liquid volumes in the secondary side; (2) the lack of direct initiation of reactor trip upon the occurrence of off-normal conditions in the feedwater system; (3) reliance on an integrated control system (ICS) to automatically regulate feedwater flow; (4) actuation before reactor trip of a pilot-operated relief valve on the primary system pressurizer (which, if the valve sticks open, can aggravate the event); and (5) a low steam generator elevation (relative to the reactor vessel) which provides a smaller driving head for natural circulation.

Because of these features, B&W designed reactors place more reliance on the reliability and performance characteristics of the auxiliary feedwater system, the integrated control system, and the emergency core cooling system (ECCS) performance to recover from frequent anticipated transients, such as loss of offsite power and loss of normal feedwater, than do other PWR designs. This, in turn, places a large burden on the plant operators in the event of off-normal system behavior during such anticipated transients.

As a result of a preliminary review of the Three Mile Island Unit No. 2 accident chronology, the NRC staff initially identified several human errors that occurred during the accident and contributed significantly to its severity. All holders of operating licenses were subsequently instructed to take a number of immediate actions to avoid repetition of these errors, in accordance with bulletins issued by the Commission's Office of Inspection and Enforcement (IE). In addition, the NRC staff began an immediate reevaluation of the design features of B&W reactors to determine whether additional safety corrections or improvements were necessary with respect to these reactors. This evaluation involved numerous meetings with B&W and certain of the affected licensees.

The evaluation identified design features as discussed above which indicated that B&W designed reactors are unusually sensitive to certain off-normal transient conditions originating in the secondary system. As a result, an additional bulletin was issued by IE which instructed holders of operating licenses for B&W designed reactors to take further actions, including immediate changes to decrease the reactor high pressure trip point and increase the pressurizer pilot-operated relief valve setting. Also, as a result of this evaluation, the NRC staff identified certain other safety concerns that warranted additional short-term design and procedural changes at operating facilities having B&W designed reactors. These were identified as items (a) through (e) on page 1-7 of the Office of Nuclear Reactor Regulation Status Report to the Commission of April 25, 1979.

After a series of discussions between the NRC staff and the licensee concerning possible design modifications and changes in operating procedures, the licensee agreed in a letter dated April 27, 1979, to perform promptly the following actions:

(a) Upgrade the timeliness and reliability of delivery from the Auxiliary Feedwater System by carrying out actions as identified in Enclosure 1 of the licensee's letter of April 27, 1979.

(b) Develop and implement operating procedures for initiating and controlling auxiliary feedwater independent of Integrated Control System control.

(c) Implement a hard-wired control-grade reactor trip that would be actuated on loss of main feedwater and/or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) Provide for one Senior Licensed Operator assigned to the control room who has had Three Mile Island Unit No. 2 (TMI-2) training on the B&W simulator.

In its letter the licensee also stated that Rancho Seco would be shut down on April 28, 1979 and would remain shut down until (a) through (e) above are completed (The facility was shut down on April 28, 1979 as stated).

In addition to these modifications to be implemented promptly, the licensee has also proposed to carry out certain additional long-term modifications to further enhance the capability and reliability of the reactor to respond to various transient events. These are:

- The licensee will provide to the NRC staff a proposed schedule for implementation of identified design modifications which specifically relate to items 1 through 9 of Enclosure 1 to the licensee's letter of April 27, 1979, and would significantly improve safety.

- The licensee will submit a failure mode and effects analysis of the Integrated Control System to the NRC staff as soon as practicable. The licensee stated that this analysis is now underway with high priority by B&W.

- The reactor trip following loss of main feedwater and/or trip of the turbine to be installed promptly pursuant to this Order will thereafter be upgraded so that the components are safety grade. The licensee will submit this design to the NRC staff for review.

- The licensee will continue operator training and have a minimum of two licensed operators per shift with TMI-2 simulator training at B&W by June 1, 1979. Thereafter, at least one licensed operator with TMI-2 simulator training at B&W will be assigned to the control room. All training of licensed personnel will be completed by June 28, 1979.

The Commission has concluded that the prompt actions set forth as (a) through (e) above are necessary to provide added reliability to the reactor system to respond safely to feedwater transients and should be confirmed by a Commission order.

The Commission finds that operation of Rancho Seco should not be resumed until the actions described in paragraphs (a) through (e) above have been satisfactorily completed.

For the foregoing reasons, the Commission has found that the public health, safety and interest require that this Order be effective immediately.

III.

Copies of the following documents are available for inspection at the Commission's Public Document Room at 1717 H Street, N.W., Washington, D.C. 20555, and are being placed in the Commission's local public document room in the Business and Municipal Department, Sacramento City - County Library, 828 I Street, Sacramento, California 95814:

(1) Office of Nuclear Reactor Regulation Status Report on Feedwater Transients in B&W Plants, April 25, 1979.

(2) Letter from J. J. Mattimoe (SMUD) to Harold Denton (NRR) dated April 27, 1979.

Accordingly, pursuant to the Atomic Energy Act of 1954, as amended, and the Commission's Rules and Regulations in 10 CFR Parts 2 and 50, IT IS HEREBY ORDERED THAT:

(1) The licensee shall take the following actions with respect to Rancho Seco:

(a) Upgrade the timeliness and reliability of delivery from the Auxiliary Feedwater System by carrying out actions as identified in Enclosure 1 of the licensee's letter of April 27, 1979.

(b) Develop and implement operating procedures for initiating and controlling auxiliary feedwater independent of Integrated Control System control.

(c) Implement a hard-wired control-grade reactor trip that would be actuated on loss of main feedwater and/or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) Provide for one Senior Licensed Operator assigned to the control room who has had Three Mile Island Unit No. 2 (TMI-2) training on the B&W simulator.

(2) The licensee shall maintain Rancho Seco in a shutdown condition (the facility was shut down on April 28, 1979) until items (a) through (e) in paragraph (1) above are satisfactorily completed. Satisfactory completion will require confirmation by the Director, Office of Nuclear Reactor Regulation, that the actions specified have been taken, the specified analyses are acceptable, and the specified implementing procedures are appropriate.

(3) The licensee shall as promptly as practicable also accomplish the long-term modifications set forth in Section II of this Order.

V.

Within twenty (20) days of the date of this Order, the licensee or any person whose interest may be affected by this Order may request a hearing with respect to this Order. Any such request shall not stay the immediate effectiveness of this Order.

FOR THE NUCLEAR REGULATORY COMMISSION

Samuel J. Chilk
Secretary of the Commission

Dated at Washington, D.C.
this 7th day of May 1979.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	Dockets Nos. 50-269
	)	50-270
DUKE POWER COMPANY	)	and 50-287
	)	
Oconee Nuclear Station, Units Nos. 1, 2 and 3	)	

ORDER

I.

The Duke Power Company (the licensee), is the holder of Facility Operating Licenses Nos. DPR-38, DPR-47 and DPR-55 which authorize the operation of the nuclear power reactors known as Oconee Nuclear Station, Units Nos. 1, 2 and 3 (the facilities, or Oconee 1, 2 and 3), at steady state power levels not in excess of 2568 megawatts thermal (rated power) for each unit. The facilities are Babcock & Wilcox (B&W) designed pressurized water reactors (PWR's) located at the licensee's site in Oconee County, South Carolina.

II.

In the course of its evaluation to date of the accident at the Three Mile Island Unit No. 2 facility, which utilizes a B&W designed PWR, the Nuclear Regulatory Commission staff has ascertained that B&W designed reactors appear to be unusually sensitive to certain off-normal transient conditions originating in the secondary system. The features of the B&W design that contribute to this sensitivity are: (1) the design of steam generators to operate with relatively small liquid volumes in the secondary side; (2) the lack of direct initiation of reactor trip upon the occurrence of off-normal conditions in the feedwater system; (3) reliance on an integrated control system (ICS) to automatically regulate feedwater flow; (4) actuation before reactor trip of a pilot-operated relief valve on the primary system pressurizer (which, if the valve sticks open, can aggravate the event); and (5) a low steam generator elevation (relative to the reactor vessel) which provides a smaller driving head for natural circulation.

Because of these features, B&W designed reactors place more reliance on the reliability and performance characteristics of the auxiliary feedwater system, the ICS, and the emergency core cooling system (ECCS) performance to recover from frequent anticipated transients, such as loss of offsite power and loss of normal feedwater, than do other PWR designs. This, in turn, places a large burden on the plant operators in the event of off-normal system behavior during such anticipated transients.

As a result of a preliminary review of the Three Mile Island Unit No. 2 accident chronology, the NRC staff initially identified several human errors that occurred during the accident and contributed significantly to its severity. All holders of operating licenses were subsequently instructed to take a number of immediate actions to avoid repetition of these errors, in accordance with bulletins issued by the Commission's Office of Inspection and Enforcement (IE). In addition, the NRC staff began an immediate reevaluation of the design features of B&W reactors to determine whether additional safety corrections or improvements were necessary with respect to these reactors. This evaluation involved numerous meetings with B&W and certain of the affected licensees.

The evaluation identified design features as discussed above which indicated that B&W designed reactors are unusually sensitive to certain off-normal transient conditions originating in the secondary system. As a result, an additional bulletin was issued by IE which instructed holders of operating licenses for B&W designed reactors to take further actions, including immediate changes to decrease the reactor high pressure trip point and increase the pressurizer pilot-operated relief valve setting. Also, as a result of this evaluation, the NRC staff identified certain other safety concerns that warranted additional short-term design and procedural changes at operating facilities having B&W designed reactors. These were identified as items (a) through (e) on page 1-7 of the Office of Nuclear Reactor Regulation Status Report to the Commission on April 25, 1979.

After a series of discussions between the NRC staff and the licensee concerning possible design modifications and changes in operating procedures, the licensee agreed in letters dated April 25, 26, and May 4, 1979 to perform promptly the following actions:

(a) Install automatic starting of the interconnected emergency feedwater system so that all three pumps will receive a start signal from any affected unit, and test the system for stability. The emergency feedwater pump discharge flow will be connected to the interconnection headers such that each or all emergency feedwater pumps can supply water to any unit. Until these modifications and tests are completed, operating personnel have been stationed at each emergency feedwater pump with a direct communication link to that unit's control room. In addition, the following procedural changes, put into effect on April 25, 1979 to enhance the reliability of the emergency feedwater system, will remain in force:

(1) The discharges of these pumps have been tied together by alignment of manual valves such that each and all of the pumps can supply emergency feedwater to any Oconee Unit requiring it.

(2) Administrative controls have been established so that in the event of loss of both main feedwater pumps on an affected unit, that unit's emergency feedwater pump will start automatically, backed up by remote manual start from the control room. If the pump fails to start automatically, the operator stationed at that pump will start the pump locally, and has been trained to do so. In addition, the other two available emergency feedwater pumps will be started remotely from their unit's control room or locally if required to provide two more redundant sources of feedwater to the affected unit.

(3) Emergency feedwater flow to the steam generators will be assured by the control room operator who has been trained to maintain the necessary level.

(b) Develop and implement operating procedures for initiating and controlling emergency feedwater independent of Integrated Control System control.

(c) Implement a hard-wired control-grade reactor trip on loss of main feedwater and/or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) All licensed reactor operators and senior reactor operators will have completed the TMI-2 simulator training at B&W.

(f) Station in the control room an additional full-time Senior Reactor Operator (SRO) (or previously licensed SRO) with Three Mile Island training for each operating unit to assist with guidance and possible manual action in case of transients until items (a) through (e) are completed.

In its letters the licensee also stated that (1) Oconee 3 would be shut down on April 28, 1979, and remain shutdown until (a) through (e) above are completed (the facility was shut down on April 28, 1979 as stated); (2) a second Oconee unit would be shut down on May 12, 1979, if items (a) through (e) have not been previously accomplished and remain shut down until items (a) through (e) have been completed; and, (3) a third Oconee unit would be shut down on May 19, 1979, if items (a) through (e) have not been previously accomplished and will remain shut down until completion of items (a) through (e).

In addition to these modifications to be implemented promptly, the licensee has also proposed to carry out certain additional long-term actions to increase the capability and reliability of the reactors to respond to various transient events. These are:

The licensee will install two motor driven pumps for each Oconee unit, as more particularly described as Part III of a letter from W.O. Parker to the NRC of April 25, 1979, to provide greater assurance of emergency feedwater supply. The licensee will submit this system concept and analysis to the NRC staff for review.

- The licensee will submit a failure mode and effects analysis of the Integrated Control System to the NRC staff as soon as practicable. The licensee states that this analysis is now underway with high prioritv by B&W.

- The reactor trip on loss of the main feedwater and/or trip of the turbine to be installed promptly pursuant to this Order will thereafter be upgraded so that the components are safety grade. The licensee will submit this design to the NRC staff for review.

- The licensee will continue reactor operator training and drilling of response procedures to assure a high state of preparedness.

The Commission has concluded that the prompt actions set forth as (a) through (e) above are necessary to provide added reliability to the reactor system to respond safely to feedwater transients and should be confirmed by a Commission order. The immediate procedural changes to assure redundant sources of auxiliary feedwater that were put into effect on April 25 at the two operating Oconee units, as described in paragraph (a) above, and the immediate additions to the operating staff, as described in paragraph (f) above, provide the bases for continued safe operation of those facilities during the interim period until May 12 and May 19, 1979, respectively. The Commission finds, however, that operation of all units should not be resumed or continued on an indefinite basis until actions described in paragraphs (a) through (e) above have been satisfactorily completed.

For the foregoing reasons, the Commission has found that the public health, safety and interest require that this Order be effective immediately.

III.

Copies of the following documents are available for inspection at the Commission's Public Document Room at 1717 H Street, N.W., Washington, D.C. 20555, and are being placed in the Commission's local public document room at the Oconee County Library, 201 South Spring, Walhalla, South Carolina 29691:

(1) Office of Nuclear Reactor Regulation Status Report on Feedwater Transients in B&W Plants, April 25, 1979.

(2) Letter from W. S. Lee (Duke Power Company) to Harold Denton (NRR), dated April 25, 1979.

(3) Two letters from W. O. Parker, Jr. (Duke Power Company) to Harold Denton (NRR), dated April 25, 1979.

(4) Letter from W. H. Owens (Duke Power Company) to Roger J. Mattson (NRR), dated April 25, 1979.

(5) Letter from W. S. Lee (Duke Power Company) to Harold Denton (NRR), dated April 26, 1979.

(6) Letter from W. O. Parker, Jr. (Duke Power Company) to James P. O'Reilly (IE), dated May 4, 1979.

IV.

Accordingly, pursuant to the Atomic Energy Act of 1954, as amended, and the Commission's Rules and Regulations in 10 CFR Parts 2 and 50, IT IS HEREBY ORDERED THAT:

(1) The licensee shall take the following actions with respect to Oconee 1, 2 and 3:

(a) Install automatic starting of the interconnected emergency feedwater system so that all three pumps will receive a start signal from any affected unit, and test the system for stability. The emergency feedwater pump discharge flow will be connected to the interconnection headers such that each or all of the emergency feedwater pumps can supply water to any unit. Until these modifications and tests are completed, operating personnel will be stationed at each emergency feedwater pump with a direct communication link to that unit's control room. In addition, the following procedural changes, put into effect on April 25, 1979 to enhance the reliability of the emergency feedwater system, will remain in force:

(1) The discharges of these pumps have been tied together by alignment of manual valves such that each and all of the pumps can supply emergency feedwater to any Oconee Unit requiring it.

(2) Administrative controls have been established so that in the event of loss of both main feedwater pumps on an affected unit, that unit's emergency feedwater pump will start automatically, backed up by remote manual start from the control room. If the pump fails to start automatically, the operator stationed at that pump will start the pump locally, and has been trained

to do so. In addition, the other two available emergency feedwater pumps will be started remotely from their unit's control room or locally if required to provide two more sources of feedwater to the affected unit.

(3) Emergency feedwater flow to the steam generators will be assured by the control room operator who has been trained to maintain the necessary level.

(b) Develop and implement operating procedures for initiating and controlling emergency feedwater independent of Integrated Control System control.

(c) Implement a hard-wired control-grade reactor trip on loss of main feedwater and/or turbine trip.

(d) Complete analyses for potential small breaks and develop and implement operating instructions to define operator action.

(e) All licensed reactor operators and senior reactor operators assigned to the Oconee control rooms will have completed the TMI-2 simulator training at B&W.

(f) Station in the control room an additional full-time Senior Reactor Operator (SRO) (or previously licensed SRO) with Three Mile Island training for each operating unit to assist with guidance and possible manual actions until items (a) through (e) are completed.

(2) The licensee shall maintain Oconee 3 in a shut down condition (the facility was shut down on April 28, 1979) until items (a) through (e) in paragraph (1) above are satisfactorily completed and such completion has been confirmed by the Director, Office of Nuclear Reactor Regulation.

(3) The licensee shall shut down a second of the three Oconee units on May 12, 1979, unless items (a) through (e) in paragraph (1) above have been satisfactorily completed and the completion has been confirmed by the Director, Office of Nuclear Reactor Regulation, before that date. In the event the second unit is shut down on May 12, 1979, it will remain shutdown until items (a) through (e) in paragraph (1) above are satisfactorily completed and such completion has been confirmed by the Director, Office of Nuclear Reactor Regulation.

(4) The licensee shall shut down the third of the three Oconee units on May 19, 1979, unless items (a) through (e) in paragraph (1) above have been satisfactorily completed and the completion has been confirmed by the Director, Office of Nuclear Reactor Regulation, before that date. In the event the third unit is shut down on May 19, 1979, it shall remain shut down until items (a) through (e) in paragraph (1) above are satisfactorily completed and such completion has been confirmed by the Director, Office of Nuclear Reactor Regulation.

(5) The licensee shall as promptly as practicable also accomplish the long-term modifications set forth in Section II of this Order.

Satisfactory completion of items (a) through (e) in paragraph (1) and in paragraphs (2) through (4) above will require confirmation by the Director, Office of Nuclear Reactor Regulation, that the actions specified have been taken, the specified analyses are acceptable, and the specified implementing procedures are appropriate.

V.

Within twenty (20) days of the date of this Order, the licensee or any person whose interest may be affected by this Order may request a hearing with respect to this Order. Any such request shall not stay the immediate effectiveness of this Order.

FOR THE NUCLEAR REGULATORY COMMISSION

Samuel J. Chilk
Secretary of the Commission

Dated at Washington, DC
this 7th day of May 1979.

NRC FORM 335 (7-77) U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET**	1. REPORT NUMBER *(Assigned by DDC)* NUREG-0560
4. TITLE AND SUBTITLE *(Add Volume No., if appropriate)* Staff Report on the Generic Assessment of Feedwater Transients in Pressurized Water Reactors Designed by the Babcock & Wilcox Company	2. *(Leave blank)*
	3. RECIPIENT'S ACCESSION NO.
7. AUTHOR(S) Division of Systems Safety and the Division of Operating Reactors, Office of Nuclear Reactor Regulation	5. DATE REPORT COMPLETED MONTH: MAY YEAR: 1979
9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)* Office of Nuclear Reactor Regulation U.S. Nuclear Regulatory Commission Washington, D. C. 20555	DATE REPORT ISSUED MONTH: MAY YEAR: 1979
	6. *(Leave blank)*
	8. *(Leave blank)*
12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)* Same as above.	10. PROJECT/TASK/WORK UNIT NO.
	11. CONTRACT NO.
13. TYPE OF REPORT Technical Report	PERIOD COVERED *(Inclusive dates)*
15. SUPPLEMENTARY NOTES	14. *(Leave blank)*

16. ABSTRACT *(200 words or less)*

The staff has conducted an evaluation of the feedwater transient at the Three Mile Island - Unit 2 (TMI-2) Nuclear Power Plant on March 28, 1979 which, through an unusual sequence of failures resulted in significant core damage. The failures occurred in the general areas of design, equipment malfunction and operator error.

The report presents the staff Task Group's early assessment of the generic aspects of the feedwater transients and the related events at TMI-2 for the purpose of determining the bases for continued safe operation of other plants similar to TMI-2 that were designed by the Babcock and Wilcox Company. The report presents the results of this assessment as a set of findings and recommendations in each of the principal review areas. The review is continuing and further information is being obtained and evaluated. Modification to the results of the initial review will be made and published as appropriate in the future.

17. KEY WORDS AND DOCUMENT ANALYSIS 17a. DESCRIPTORS

Feedwater transients, significant core damage, light water reactors.

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT	19. SECURITY CLASS *(This report)*	21. NO. OF PAGES
Unlimited Availability	Unclassified	
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE $

NRC FORM 335 (7-77)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

POSTAGE AND FEES PAID
U.S. NUCLEAR REGULATORY
COMMISSION

U.S. MAIL

120555004012 1 9E9F9G9H9I9J
US NRC
SD MATERIAL SAFETY STANDARDS
ASSISTANT DIRECTOR
NL5650
WASHINGTON DC 20555